

SKM 3413 - DRILLING ENGINEERING

Chapter 6 – Well Control

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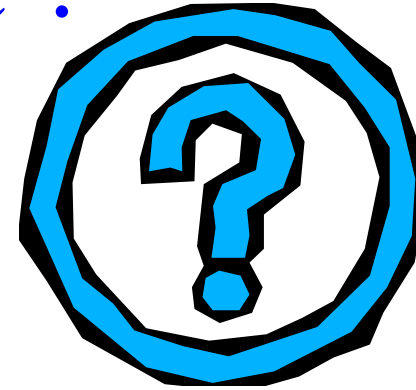
- The drilling well must at all time be under control
- The driller/operator must be in the full control over the well and at all time be able to prevent the formation fluids from flowing up the well
- The necessity for adequate well control and its effects on the drilling operation can be significant
- At best, the loss of well control results in both rig time and additional chemicals required to kill the well
- At worst, the loss of control can result in the loss of both crew lives and the well and additionally can require vast amounts of expenditure to control the well and to compensate for the undesirable effects the blow out may have had on the environmental around the well

In offshore environment, the effects can be even more catastrophic since:

- The safe evacuation of the crew is critical (weather, etc.)
- Offshore rig is very expensive
- Logistic problem and delay of the supply of the necessary materials and equipment
- If the control of the well is unsuccessful, pollution will occur due to oil spill
- The loss of rig or platform could result in delay of FDP programs

What is Blow Out ?

- Any uncontrolled pressure or formation fluids that enter into the well during drilling operation and starts to explode



Causes of Blowout

- Underbalance (low density mud, water, foam, air)
 - Reduce formation damage
 - Save money but the risk of occur blowout increased
- Overbalance
 - Safety but has its limitation
 - If overbalance pressure is too high → may break the formation and cause lost circulation → lead to a blowout
- Swabbing (tripping out)
 - Pulling the drill string too fast out of the hole will cause suction
 - Reduce the pressure below the bit invites a kick
- Going too fast in the hole (tripping in)
 - Break the formation → can cause lost circulation
- Falling object hitting and ruining the BOP
- Equipment, such as plugs, BOP, DHSV fails in a critical moment

Why well control and blow out prevention is important?

- Higher drilling costs
- Injuries and possible loss of life
- Lost of revenue
- Waste of natural resources when blow out occur
- Environmental effects
- Government regulation and restriction

How to prevent blowout?

- The best solution is to prevent before it happen
 - Develop a drilling plan, including a drilling fluid design
 - The proficiency of rigs crew and supervisors and their ability to put contingency to work
 - Added precautions often taken in drilling exploratory wells
 - Identify the presence of shallow gas

Types of well control

The control of a well refers to the ability to prevent formation fluids flowing up the well bore and being released at the surface

- Firstly, well control can refer to the prevention of formation fluids entering the well bore → referred to as primary control
- Secondly, should primary control fail and fluids enter the well bore, there is the requirement to be able to allow the influx to be discharged at surface in a controlled manner and concurrently to prevent additional influx of fluid into the well bore → referred to as secondary control

Primary control

- This is the prevention of the influx of formation fluids into the wellbore by ensuring that the hydrostatic pressure in the wellbore is at all times greater than the formation pressure:

$$P_{\text{hyd}} > P_{\text{f}}$$

- The hydrostatic pressure may be too low because of the following reasons:
 1. Insufficient fluid density
 2. Insufficient height of fluid column

1. Insufficient fluid density

Insufficient fluid density could have been created by the following:

- Inaccurate measurement of fluid density
- High temperature encountered hence a reduction in density occurs due to fluid expansion
- At watering back (after mud return, water loss due to evaporation, filtration loss, etc) excessive dilution may occur
- Too fine mesh used at the shale shaker lead to removal of weighting solids

2. Insufficient height of fluid column

The majority of blowouts occurs when the height of the fluid column reduced:

- Failure to keep the hole full when tripping out
- Swabbing effect (drill pipe acts as a piston):
 - Pulling the pipe upwards too quickly
 - Using mud of very high gel strength
 - Having small annular clearance
 - Ineffective cleaning of the bit to remove drill cuttings (e.g. bit balling)
- Loss circulation occurring into the formation
- Collapse of casing or leakage into the wellbore

Secondary control

- When primary control is lost, it is not normally possible to kill the well immediately
- The well is then shut in to prevent further influx into the wellbore; and usually, this is only a temporary measure
- Secondary control therefore refers to the use of mechanical devices used to close off the well
- This device is called a blowout preventer (BOP)
- The safety and efficiency of the control depends on the integrity of the casing strings, well head and fittings

Secondary control could be lost due to several reasons:

- Mechanical failure of the BOP
- Late identification of the influx
- Casing fails to burst which will render a loss to the annular pressure seal, hence the BOP will be ineffective
- Bad cement bond – the influx will channel through the cement, hence it will be discharged uncontrollably

Operational guidelines to the maintenance of primary control

Careful attention should be paid to the following factors to ensure that primary control is maintained:

- Maintenance of the correct mud weight
 - Gas cutting
 - Solids removal
 - Excessive dilution
- Maintenance of sufficient height of mud column
 - Precautions whilst drilling
 - Precautions before tripping
 - Precautions whilst tripping
 - Precautions whilst running casing
 - Lost of circulation
 - Drilling break

- To bring oil and gas to the surface → drill hole
- When the rock on earth that hold back formation pressures are removed:
 - The pressure will be released and free to flow
 - To control → use drilling fluid (create hydrostatic column of sufficient weight)
- Generally, the deeper the well goes, the higher the formation pressures that must be retained, therefore, mud weight must be increased to keep the well formation pressure

Some blowouts stop by themselves by one of these reasons:

- Depletion of source
- Bridging of the well bore by cave-in of open hole
- Choking of the formation by entrained material
- Choking the well bore by entrained sand, etc

Who shall stop blowouts ?

- When a blowout occurs, the operators shall leave the location immediately and never make heroic attempts to stop it. That would simply be too risky!
- In the stressed situation the possibility of making fatal mistakes is overwhelming
- Any attempt to stop a blowout required proper planning, equipment and a special type of people

What is kick?

- The pressure found within the drilled rock is greater than the mud hydrostatic pressure acting on the borehole or face of the rock
- Therefore, the formation pressure has a tendency to force formation fluids into the wellbore
- If the flow is successfully controlled → the kick has been killed, if not → blowout

Calculations

Example: What overbalance would there be in a hole drilling at 7,000 ft if the mud weight is 9.5 ppg and the formation pressure is 3,255 psi?

Solution:

$$\Delta P = 0.052 (9.5) (7,000) - 3,225 = 203 \text{ psi}$$

Example: A well is drilling at 7,000 ft using 10.5 ppg mud. A kick is encountered and the well is closed in. The SIDPP registers 250 psi. What is the new formation pressure and what mud weight will be required to balance?

Solution:

$$\text{New } P_f = 0.052 (10.5) (7,000) + 250 = 4,072 \text{ psi}$$

$$\text{New mud weight} = \frac{4,072}{0.052 (7,000)} = 11.2 \text{ ppg}$$

Example: A well is drilling at 5,000 ft using 10 ppg mud. A kick occurs and the well is closed in. The SIDPP builds up to 400 psi. What is the new formation pressure? What mud weight will be required to enable us to drill ahead using 150 psi overbalance?

Solution:

$$\text{New } P_f = 0.052 (10) (5,000) + 400 = 3,000 \text{ psi}$$

$$\begin{aligned} \text{New mud weight @ 3,000 psi and 150 psi } \Delta P &= \frac{(3,000 + 150)}{0.052 (5,000)} \\ &= 12.1 \text{ ppg} \end{aligned}$$

What turns a kick into a blowout?

Lack of proper control !!

- The key objectives in blowout prevention are:
 - To detect the kick as soon as possible
 - To take steps to control the circulation of the kick out of the well
 - To take steps to increase the density of the fluid in the well to prevent further fluids from entering the well

All kicks in some way are related to drilling fluid

The severity of the kick depends upon several factors:

- The ability of the rock (porosity, permeability) to allow fluid flow to occur
 - A rock with high porosity and permeability has a greater potential for severe kick (e.g. sandstone is considered to have a greater kick potential than shale)
- The amount of pressure differential involved

Causes of kicks

1. Insufficient mud weight
2. Improper hole fill-up during trips
3. Swabbing
4. Cut mud
5. Lost circulation

1. Insufficient mud weight

- One of the predominant causes of kicks
- Pressure imbalance → fluids begin to flow into the wellbore
- Normally associated with abnormal formation pressures
- Very high mud weight (overbalance) cannot be used because:
 - High mud weight may exceed the fracture gradient of the formation and induce an underground blowout
 - Slightly reduce penetration rates
 - Pipe sticking

Therefore, maintain the mud weight slightly greater than the formation pressure until that time the mud weight begins to approach the fracture gradient requiring an additional string of casing

2. Improper hole fill-up during trips

- As the drill pipe is pulled out of the hole, the mud level falls because the drill pipe steel had displaced some amount of mud
- With the pipe no longer in the hole, the overall mud level will reduce, therefore, the hydrostatic pressure of the mud will decrease

Therefore, it is necessary to fill the hole with mud periodically to avoid decreasing of hydrostatic pressure

3. Swabbing

- Swab pressures are pressures created by pulling the drill string from the borehole
- This action will reduce the effective hydrostatic pressure throughout the hole below the bit
- If this pressure decrease is large enough, there will be potential kick
- Reasons
 - Pipe pulling speed
 - Mud properties
 - Hole configuration (large swab pressure for small hole)
 - Bit balling effect

4. Cut mud

- Gas contaminated mud will occasionally cause a kick although this occurrence is rare
- Mud density will decrease
- As gas is circulated to the surface, it may expand and decrease the overall hydrostatic pressure to a point sufficient to allow a kick to occur
- Although the mud weight is cut severely at the surface, the total hydrostatic pressure is not decreased significantly since most of the gas expansion occurs near the surface and not at the bottom of the hole

5 Lost circulation

- Decreased hydrostatic pressure occurs due to a shorter column of mud
- When a kick occurs as a result of lost circulation, the problem may become extremely severe since a large amount of kick fluid may enter the hole before the rising mud level is observed at the surface

Warning signs of kicks

1. Flow rate increase
2. Pit volume increase
3. Flowing well with pumps off
4. Pump pressure decrease and pump stroke increase
5. Improper hole fill-up on trips
6. String weight change
7. Drilling break
8. Cut mud weight

1. Flow rate increase

- When pumping at a constant rate, the flow rate increase more than normal i.e. formation is aiding the rig pumps in moving the fluid up the annulus by forcing formation fluids into the wellbore

2. Pit volume increase

- If the volume of fluid in the pits is not changed as a result of surface controlled actions, therefore, an increase in pit volume indicates that a kick is occurring
- The fluids entering the wellbore as a result of the kick displace an equal volume of mud at the flow line and result in a pit gain

3. Flowing well with pum

- When the rig pumps are not moving the mud, a continued flow from the well indicates that a kick is in progress

4. Pump pressure decrease and

- A pump pressure change may indicate a kick
- The initial entry of the kick fluids into the borehole may cause the mud to flocculate and temporarily increase the pump pressure
- As the flow continues, the low density influx will displace the heavier mud and the pump pressure may begin to decrease
- As the fluid in the annulus become less dense, the mud in the drill pipe will tend to fall and the pump speed may increase

5. Improper hole fill-up on trips

- When the drill string is pulled out of the hole, the mud level should decrease by a volume equivalent to the amount of steel removed
- If the hole does not require the calculated volume of mud to bring the level back to the surface, a kick fluid has entered the hole and filled the displacement volume of the drill string

6. String weight change

- The mud provide a buoyant effect to the drill string, heavier muds have a greater buoyant force than less dense muds
- When kick occurs, the mud density will decrease and as a result, the string weight observed at the surface begin to increase

7. Drilling break

- An abrupt increase in bit penetration rate (shows a new rock type), called a drilling break, is a warning sign of possible kick
- Although the drilling break occur, it is not certain that a kick will occur, therefore, it is recommended to drill 3 – 5 ft into the sand and stop to check for flowing formation fluids

8. Cut mud weight

- Decreased mud weight observed at the flow line has occasionally caused a kick to occur
- Possible causes is gas (also oil and water) entering the formation
- However cut mud weight have small effect

Procedures in the event of a kick

- At the first indication of a kick
 - Stop drilling
 - Raise the bit off the bottom of the well (to shut in the well)
 - Stop the pumps and check to see if there is a flow from the well
 - If the well does flow, close the BOP and shut in the well
- Readings are taken to stabilize shut in drill pipe and casing pressures
- Calculations are made to determine the density of the mud that will be used to kill the well
- Calculations are also made to determine the kick out, and to fill the hole with new mud

- Handling procedures of a kick may vary, and no one method can be employed to each kick situation
- Factors affecting kill procedures are:
 - The area where the well is being drilled
 - The depth of the well
 - The operational procedures adopted by the contractor
 - The equipment available

Methods of killing kicks

- There are many kick-killing methods, some of these have utilized systematic conventional approach while others were based on logical, but perhaps unsound, principles
- Commonly used methods:
 1. One circulation method
 2. Two circulation method
 3. Concurrent method
- If applied properly, each of these 3 methods will achieve the constant pressure at the hole bottom and will not allow any additional influx into the well

1. One circulation method

- After the kick is shut in, weight the mud to kill density, then pump out the kick fluid in one circulation using the kill mud
- Other names: wait and weight method, engineer's method, graphical method, constant drill pipe pressure method

2. Two circulation method

- After the kick is shut in, the kick fluid is pump out of the hole before the mud density is increased
- Other names: driller's method

3. Concurrent method

- Pumping begins immediately after the kick is shut in and the pressures are recorded
- The mud density is increased as rapidly as possible while pumping the kick fluid out of the well

1. One circulation method

- At point 1, the SIDPP is used to calculate the kill mud weight, after which the mud weight is increased to kill density in the suction pit
- As the kill mud is pumped down the drill pipe, the static DPP is controlled to decrease linearly, until at point 2 the DPP would be zero
- This results from heavy mud having killed the DPP
- Point 3 illustrate that the initial pumping pressure on the drill pipe would be the total of the SIDPP plus the kill rate pressure, or 1,500 psi:

$$\begin{aligned}\text{Initial pumping } P &= \text{SIDPP} + \text{kill rate } P \\ &= 500 + 1,000 \\ &= 1,500 \text{ psi}\end{aligned}$$

- While pumping kill mud down the pipe, the circulating pressure should reduce until at point 4, only the pumping pressure remains
- From the time that the kill mud reaches the bit until the kill mud reaches the flow line, the choke controls the DPP at the circulating pressure while the driller insures that the pump remains at the kill speed

2. Two circulation method

- Kill mud is not added in the first circulation, i.e. DPP will not decrease during this period
- The purpose of this circulation is to remove the kick fluid from the annulus
- In the second circulation, the mud weight is increased and causes a decrease from the initial pumping pressure at 1 to the final circulating pressure at 2
- The final circulating pressure is held constant thereafter while the annulus is displaced with the kill mud

3. Concurrent method

- As soon as the kick is shut-in, pumping begins immediately after reading the pressures and the mud density is pumped as rapidly as possible
- However, it is difficult to determine mud density being circulated and its relative position in the drill pipe
- Since this position determines the DPP, it will give irregular pressure drops
- As a new density arrives at the bit or some predetermined depth, the DPP is decreased by an amount equal to the hydrostatic pressure of the new mud density increment
- When the drill pipe is completely displaced with kill mud, the pumping pressure is maintained constant until kill mud reaches the flow line

Choice of method

- Determining the best control method, suitable for the most frequently met situations, involves several important considerations:
 - The time required to execute the entire kill procedure
 - The surface pressures arising from the kick
 - The complexity of the procedure itself, relative to the ease of carrying it out
 - The downhole stresses applied to the formation during the kick killing process
 - All of these factors must be analyzed before a procedure can be selected
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Advantages and disadvantages of driller's method

Advantages

- Simple to teach and understand
- Very few calculations
- In case of saltwater, the contaminant is moved out quickly to prevent sand settling around drilling assembly

Disadvantages

- Higher casing shoe pressure (kick)
- Higher annular pressure (kick)
- Takes two circulations

Advantages and disadvantages of wait-and-weight method

Advantages

- Lowest casing pressure
- Lowest casing seat pressure
- Less lost circulation (if not over killed)
- Killed with one circulation if contaminant does not string out in washed out sections of hole

Disadvantages

- Requires the longest non-circulating time while mixing heavy mud
- Pipe could stick due to settling of sand, shale, anhydrite or salt while not circulating
- Requires a little more arithmetic

Advantages and disadvantages of concurrent method

Advantages

- Minimum of non-circulating time
- Excellent for large increases in mud weight (under balanced drilling)
- Mud condition (viscosity and gels) can be maintained along with mud density
- Less casing pressure than driller's method
- Can be easily switched to weight-and-weight method

Disadvantages

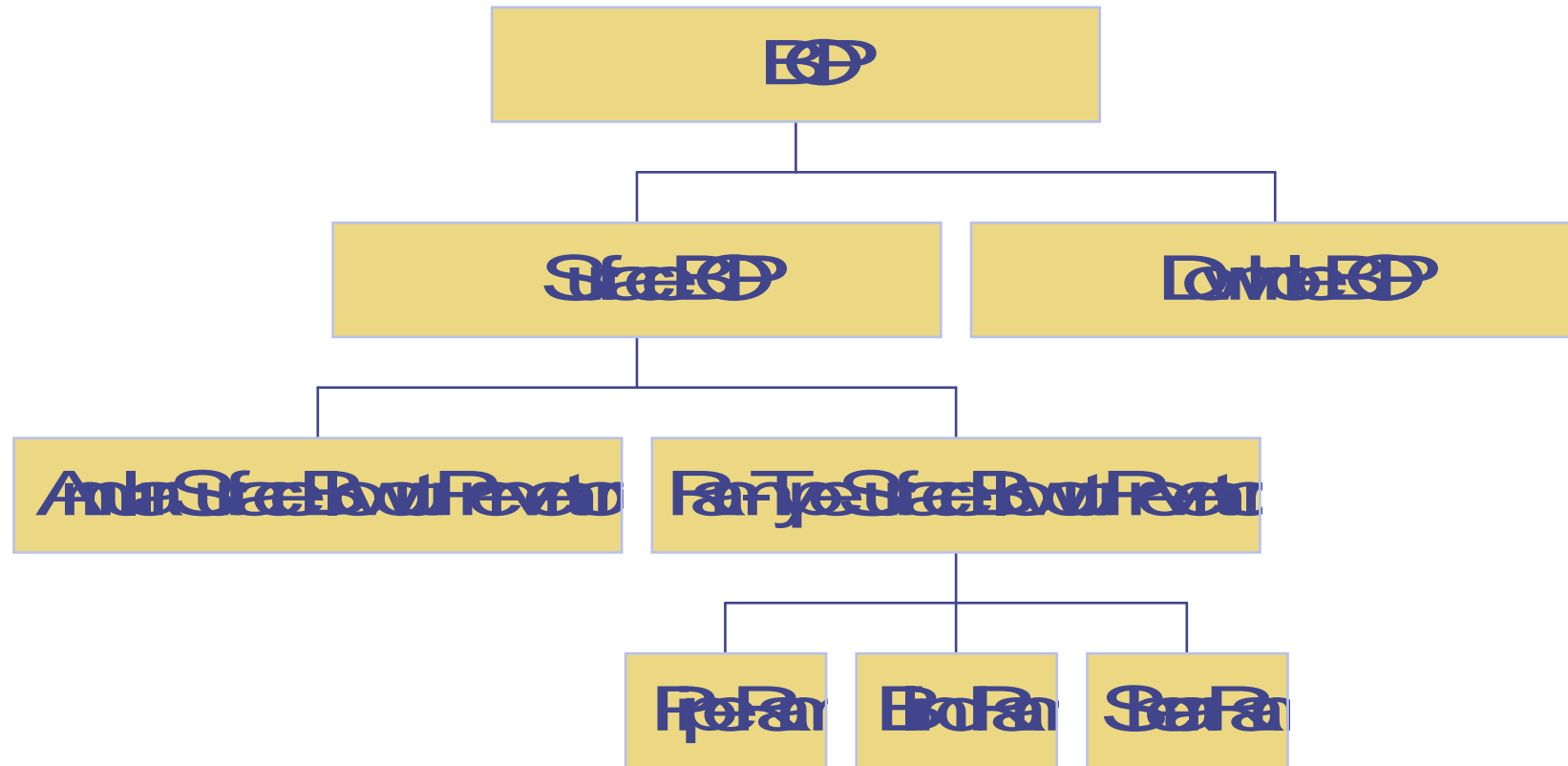
- Arithmetic is a little more complicated
- Requires more, on-choke, circulating time
- Higher casing and casing seat pressure than wait-and-weight method

What is BOP?

- The BOPs are a series of powerful sealing elements designed to closed off the annular space between the drill pipe and the hole through which the mud normally returns to the surface
- Valves are installed on the pipe or wellhead to prevent the escape of pressure either in the annular space between the casing and drill pipe or in open hole during drilling, completion and work over operations
- By closing this valve, the drilling crew usually regains control of the reservoir with increase the mud density until it is possible to open the BOP and retain pressure control the formation
- They can be hydraulically, manual or air operated and in some cases a combination of all three

Types of BOP

- BOPs come in a variety of styles, size and pressure ratings
- Some BOPs can effectively close over an open wellbore, some are designed to sealed around tubular components in the well (drill pipe, casing and tubing) and others are fitted with hardened steel shearing surface that can actually cut through drill pipe



Annular preventers

- A large valve used to control wellbore fluids
- Design to shut off around any size of equipment run through the hole
- Most blowout preventer (BOP) stack contains at least one annular BOP at the top of the BOP stack, and one more ram-type preventers below
- It can close around drill pipe, drill collars and casing, and also pack off an open hole
- Is a well's master valve and normally closed first in the event of a well kick, owing to flexibility of the closing rubbers
- It can only be closed hydraulically by directing fluid under pressure to the operating cylinder through the closing chamber

Pipe rams

- Design to close around a particular size of drill pipe, tubing or casing
 - The pack off is provided by two steel ram blocks containing semi-circular openings with each ram being fitted with a two-piece rubber seal
 - The semi-circular openings can seal around the outside diameter of the drill pipe, tubing, drill collar, kelly or casing, depending on the size of the rams chosen
 - It can be close manually or hydraulically to seal off the annular
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Blind rams

- Quiet similar to pipe rams
 - Except that packer are replaced by ones that have no cutouts in the rubber
 - Has no space for pipe and is instead blanked off in order to be able to close over a well that does not contain a drill string
 - Designed to seal off the bore when no drill string or casing is present
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Shear rams

- A BOP closing element fitted with hardened tool steel blades
- Designed to cut the drill pipe when the BOP is closed
- Normally used as a last resort to regain pressure control of a well that is flowing
- Once the drill pipe is cut, it is usually left hanging in the BOP stack and kill operations become more difficult
- The joint of drill pipe is destroyed in the process, but the rest of the drill sting is unharmed by the operation of shear rams

Nowadays BOP's...

- Can be instrumented to sense, quantify and remember pressures, temperatures, on/off status and incremental ram positions
- The BOP Stack can be cleaning
- Top and bottom unions are removable
- The hydraulic actuators require a very low hydraulic pressure to close and they close easily at high pressure

Nowadays BOP's...

- Equalizing valves are strong, durable, and their flow is very controllable
- Minimum height enables service rigs to work closer to ground level
- An innovative attribute on the BOP is the plumbing feature. Single point open and close ports in each modular body permit operation of both hydraulic for each set of rams
- Operating volumes are lower, resulting in faster closing times and smaller accumulator requirements

Control system equipment

- Pressure accumulator system
- Power availability
- Accumulator pump capacity
- Locking devices
- Remote controls
- Choke and kill line

BOP stack cleaning

- Combination of mechanical and chemical cleaning technology to remove undesirable solids and other debris from the interior of the stack
- Mechanical jetting is one of the most effective cleaning methods- water jetting application

Innovative and modern BOP's...

- Coiled tubing BOP is available in bore sizes from 2 9/16" to 7 1/16" and working pressures from 5000 to 15,000 psi, with the following features:
 - Manual or hydraulic open/close bonnets for easy ram change
 - Internal hydraulics; no external hoses assemblies
 - All rams hydraulically actuated with visual position indicator and manual lock
 - One-piece, forged-steel body
 - Available in single, dual, triple and quad configurations

- Hydraulic over air pressure transmitters to convert critical hydraulic pressures to low-pressure air signals to be transmitted by the control air hose bundles to the remote panels
- Fail-safe, air motor-driven, pressure-reducing and -regulating valve (with manual override) to control hydraulic pressure to annular-type BOP

Remote Control Panels

Choke Manifold Valve Control Panels

- Designed for remote control of choke manifold hydraulic-actuated valves

Wall-mounted Panels

- Designed to be used as driller's station remote panel or auxiliary panel

Stand-alone Panels

- Air-operated panels for driller's station remote panel or auxiliary panel

BOP safety

- Well control equipment that is to be install must be rate above the maximum expected formation pressure of the well about to be drilled
- Tested immediately after installation
- Maintained ready for use until drilling operations are completed
- Control panel must be located at sufficient distance from well head
- BOP equipment must be pressure tested