IWCF Exercises

Part 1: Equipment

Version: Nov-19

1 Diverter

1.1 When drilling shallow formations with no BOP installed, how often should you function test the diverter as per API standards?

a. Daily
b. Every 21 days
c. Only when first installed
d. Weekly

1.2 What happens when the diverter is closed?

a. The diverter packer and vent line valve close at the same time
b. The diverter packer closes and then the shaker line valve closes
c. The diverter packer closes and then the vent line opens
d. The vent line valve opens and then the diverter packer closes

1.3 What is the weakest point of the diverter?

a. Ball valve
b. Flow line connector seal.

1.4 How can back pressure be reduced inside a diverter?

a. Use dual active vent
b. Minimize internal control valves
c. Use short (straight) vent line with large ID.
d. Use vent line to separator.

1.5 Which statements are correct about diverter vent lines? *(Two answers)*

a. Diverter vent lines must be as straight as possible.
b. Diverter vent lines must have bends to create back pressure.
c. Diverter vent lines must be routed directly to the Mud Gas Separator (MGS)
d. Diverter vent lines must have a large internal diameter to reduce back pressure
e. Diverter vent lines must have small internal diameters to create back pressure

1.6 What is good practice for diverter vent line systems?

a. Diverter vent line bends can have full-bore rubber hoses installed.
b. Diverter vent lines should have options to allow discharge down-wind of the rig.
c. Diverter vent lines should be routinely pressure tested.
d. Diverter vent lines can have bends as they are not designed to hold high pressures.

1.7 If the Diverter has two vent lines, and the wind is from east to west. In case of shallow gas what the driller should do?

a. Open the Both vent lines, then active the diverter packer then close the east
b. Open the both vent lines, then active the diverter packer then close the west
c. Close the two vent lines, then active the diverter packer the open the both vents

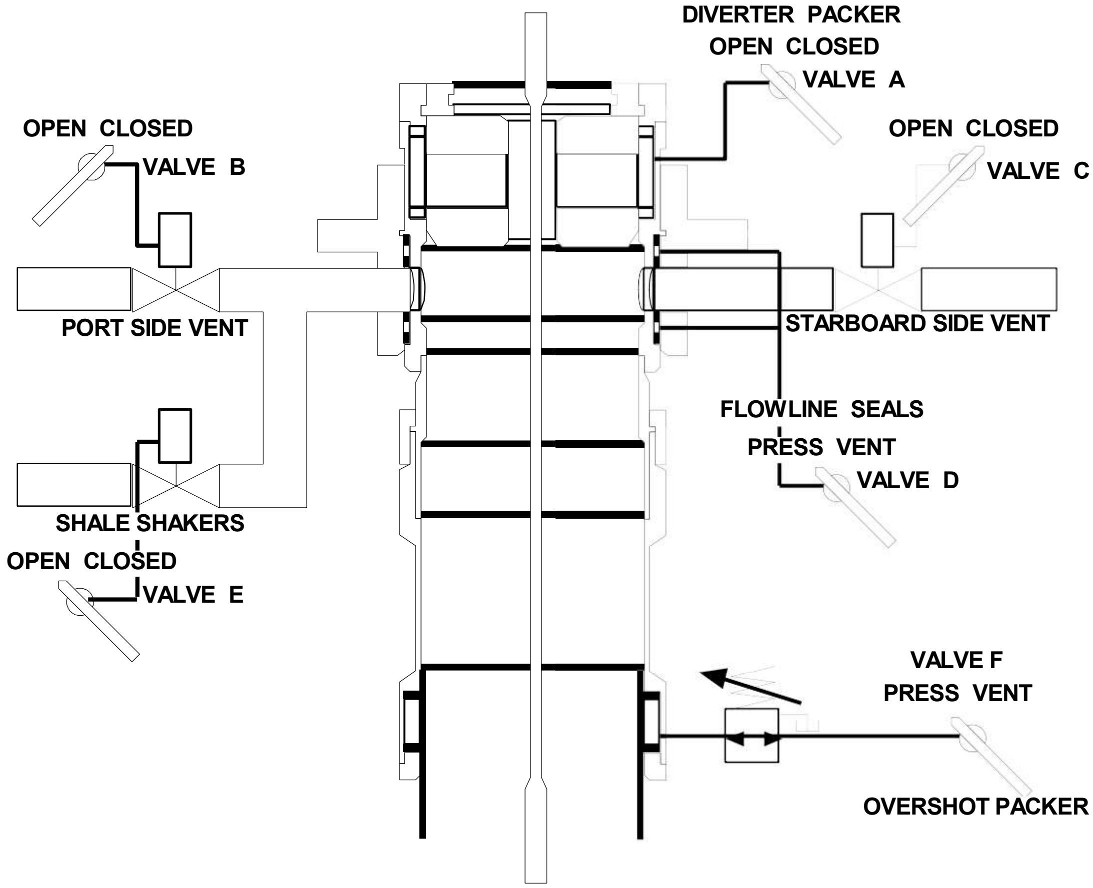
1.8 You are drilling top-hole with a diverter installed. The flow line is above the diverter, and the overboard vent lines are below the diverter. The wind is coming from the east. What pre-shift instructions would you give to the Driller about the divert procedure for this day?

a. Close the flow line before opening the overboard line to the east.
b. Close the flow line before opening the overboard line to the west.
c. Open the overboard vent line to the east, close the overboard vent line to the west, and then close the diverter.
d. Open both overboard vent lines, close the diverter, and then close the overboard vent line to the east.

1.9 What design feature do diverter systems have to minimize back-pressure on the well?

a. Dual active vent lines with minimum bore control valves
b. Large internal diameter, straight and short vent lines
c. Small internal diameter, with targeted bends and maximum length vent lines
d. The diverter element closes before the selector valve opens

1.10 The illustration shows diverter system during a drilling operation, with wind blowing from starboard to port. What is the correct operational sequence for this diverter system?



Select the correct operation sequence of the valves in case the well starts to flow.

a. Pressure A, then Close E, and then open C.

b. Open C, then close E, then pressure A.

c. Open C, then vent F, and then close E.

d. Open B, then Close E, then pressure A.

1.11 What are the components of a 29-1/2 inch diverter system? ***(Two answers)***

a. A low pressure annular preventer with a large internal diameter.

b. A vent line of sufficient diameter to permit safe venting using the mud-gas separator.

c. A high pressure rams type preventer with a large internal diameter.

d. A vent line with a manually operated full opening valve.

e. A vent line of sufficient diameter to permit safe venting and proper disposal of flow from the well.

1.12 Which of the following factors LIMIT the success of diverter operation when shallow gas blow out occurs? ***(Three answers)***

a. Rig air pressure of Zero psi.

b. The formation strength at the conductor/casing shoe.

c. Diverter lockdown doges unlocked.

d. Diverter lockdown doges locked.

e. Rig air pressure of 125 psi

f. Mud pumps running, pumping mud to the bottom of the well

1.13 While drilling top-hole with an insert type diverter, what must you do when running or pulling the Bottom Hole Assembly (BHA)?

a. Grease the tool joints.

b. Open the overboard line.

c. Reduce the diverter packer pressure to zero.

d. Remove the insert packer.

1.14 What is the main advantages of insert type diverter compared to conventional large annular type of diverter?

a. Insert type can allow large diameter tools to be run without remove the insert.

b. Can hold higher pressure.

c. Lower closing volume and is faster to flowing

e. Longer to close reduce hydrostatic shock

1.15 What is the minimum pressure for diverter pressure test?

a. 100 psi.

b. 200 psi.

c. 300 psi.

d. 400 psi.

2 <u>BOP-General</u>

2.1 Which pressure should be used to determine the rated working pressure of the ram type BOP to be installed on the well?

a. Maximum anticipated bottom hole pressure
b. Maximum anticipated hydrostatic drilling mud pressure
c. Maximum anticipated pore pressure
d. Maximum anticipated surface pressure

2.2 When should well control equipment on surface BOP installation be pressure tested? *(Two answers)*

a. After circulating out a gas kick
b. After the disconnection or repair of any pressure containment seal in the BOP system, choke line or choke manifold.
c. At intervals not exceeding two months.
d. Before spudding or upon installation.
e. When maximum anticipated surface pressure exceeds BOP rated pressure.

2.3 Regarding the Rated Working Pressure (RWP) of a BOP, are the following statements true or false?

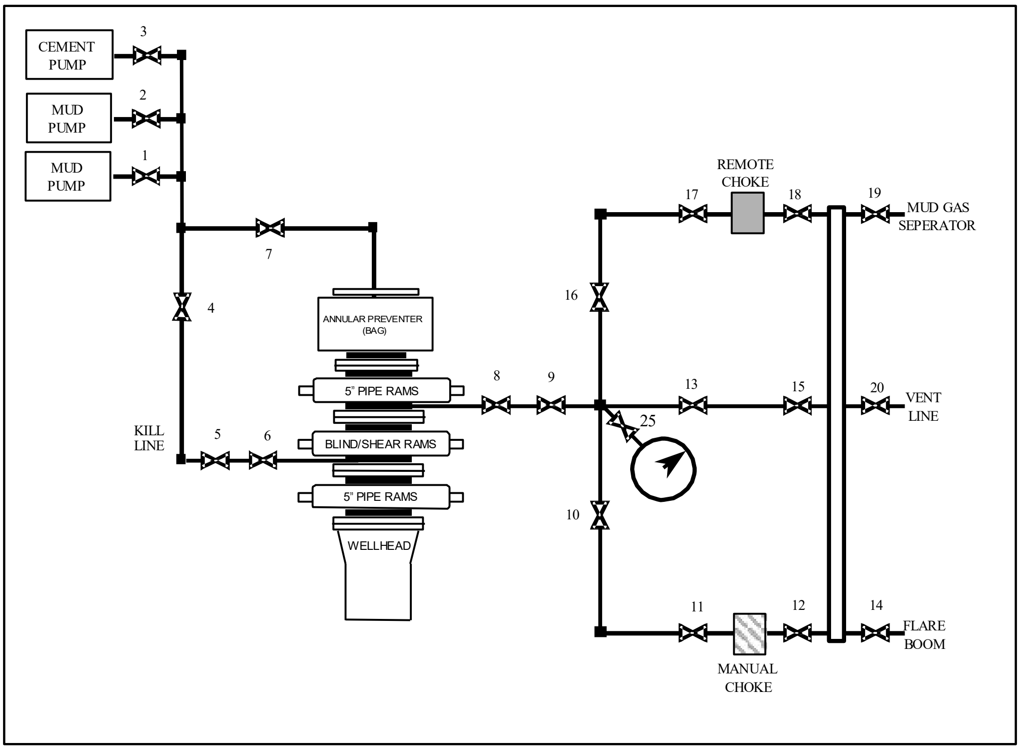
i. The criteria used to determine the required R.W. P. of a BOP is the maximum anticipated surface pressure.

a. True.
b. False.

ii. The Rated Working Pressure of a BOP is the maximum internal pressure it is designed to hold.

a. True.
b. False.

2.4 A leak-off test is to be performed using the high-pressure cement pump.

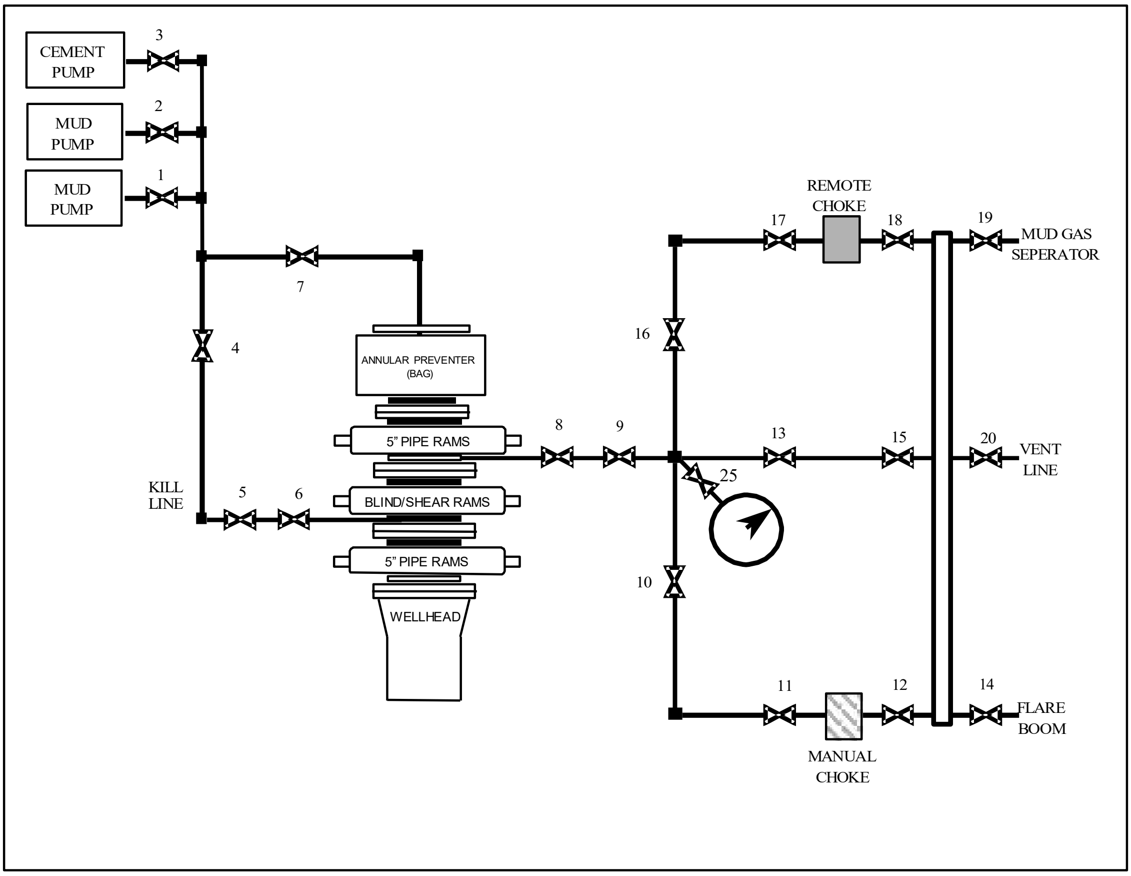


Which five (5) valves must be opened in the Figure above, when pumping down the drill string and reading the pressure from the choke manifold gauge?

Valves to be Open: ☐ ☐ ☐ ☐ ☐

2.5 Figure illustrates a typical piping schematic for a surface BOP installation. All the valves are numbered.

The well is shut in on the Annular BOP.
Mud will be circulated from the cement pump through the drill string and bled off through the manual choke to the mud gas separator.



Which one of the following groups of valves must be open to kill the well safely and monitor the operation?

a. Valve No.: 2, 3, 5, 8, 9, 10, 11, 14, 19

b. Valve No.: 1, 3, 4, 6, 7, 8, 10, 11, 13, 18, 25

c. Valve No.: 3, 7, 8, 9, 10, 11, 12, 19, 25

d. Valve No.: 2, 3, 5, 8, 9, 10, 11, 12, 15, 17

e. Valve No.: 3, 5, 8, 9, 10, 11, 14, 16, 19, 25

f. Valve No.: 2, 3, 4, 6, 7, 8, 9, 10, 11, 14, 16

2.6 A BOP Stack and wellhead have the pressure ratings:

Wellhead 10000 psi

Pipe rams 10000 psi

Blind shear rams 10000 psi

Side outlet valves 10000 psi

Annular 5000 psi

String valves (full open and non-return) 10000 psi

Rotary hose 8000 psi

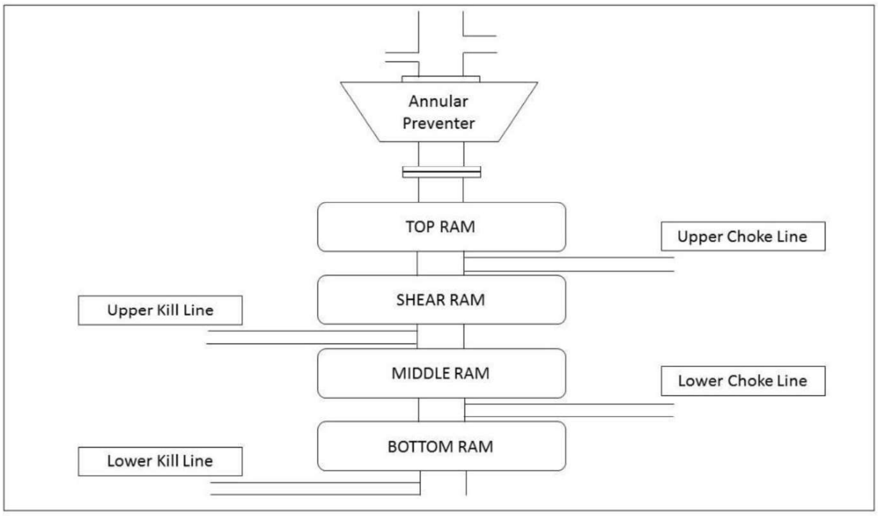
Choke manifold and pipework upstream of chokes 10000 psi

Choke manifold valves and pipework downstream of chokes 5000 psi

If the maximum anticipated surface pressure is 8200 psi, what changes are required to pressure integrity?

a. Replace the 5000 psi annular with a 10000 psi rated annular
b. Replace the 8000 psi rotary hose with a 10000 psi rated hose
c. The stack rating is acceptable, no changes are required
d. Upgrade the choke manifold downstream of the chokes to 10000 psi

2.7 In the diagram of 10000-psi (10K) surface BOP stack, why is the kill line outlet placed below the lower ram?



a. To allow the use of Volumetric Method
b. To allow the well to flow to the flare line
c. To kill the well using the Driller's method or the Wait and Weight Method.
d. To monitor the well or bullhead if the lower ram is closed.

2.8 If the well head RWP is 15,000 psi, and the BOP RWP is 10.000 psi. What is the Maximum surface pressure that can be closed in.

a. 15,000 psi

b. 25,000 psi

c. 10,000 psi

2.9 A surface stack BOP consists of:

1 x 10000 psi rated annular preventer

1 x 10000 psi rated 5”pipe rams

1 x 10000 psi rated blind/shear rams

1 x 15000 psi rated drilling spool

1 x 10000 psi rated 5”pipe rams

What is the maximum wellbore rated pressure of this stack?

a. 15000 psi

b. 20000 psi

c. 55000 psi

d. 10000 psi

2.10 Why there is a manual valve installed before the HCR on the BOP sides?

a. The manual valve acts as a barrier if the HCR needs maintained or repaired.

b. To increase the back pressure downhole for a safety margin

c. To minimize the build-up of cuttings at the drilling spool side outlets.

d. To protect the HCR valve from eroding while cementing.

2.11 The well starts to flow while you are repairing the choke line High Closing Ratio (HCR) valve. Which two barriers must be in place to allow you to continue to replace the valve?

a. Choke line manual valve and the bottom pipe ram

b. The bottom pipe ram and drilling fluid

c. The drilling fluid and choke line manual valve

2.12 There is a drill pipe in the hole and you are monitoring the well on the trip tank. Which two barriers must be in place while repairing the choke line High Closing Ratio (HCR) valve?

a. The blind ram and the manual stack valve

b. The drilling fluid and the bottom pipe ram

c. The manual choke line valve and the drilling fluid

d. The manual stack valve and the annular

2.13 Losses can be detected by: ***(Three answers)***

a. Trip tank

b. Flow sensor

c. Pit volume totalizer.

d. Mud density

2.14 A long series of electric logs will be run in a well with a small overbalance. What is the safest action to be taken?

a. Install and pressure test the appropriate riser/lubricator assembly

b. Reduce the number of electric logs to be run

c. Replace a set of shear/blind rams with a set of pipe rams

d. Run the logs as no additional equipment is required

2.15 A surface stack BOP consists of:

1 x 10000 psi rated annular preventer

1 x 10000 psi rated 5”pipe rams

1 x 10000 psi rated blind/shear rams

1 x 15000 psi rated drilling spool with 10000-psi rated remotely operated side outlet valves

1 x 10000 psi rated Variable Bore Pipe Rams

Which operation can you do keeping control of the Bottom Hole Pressure (BHP)?

a. Circulating out an influx while shut in on the lower pipe rams

b. Stripping 5-inch pipe to bottom ram to ram

c. Stripping 6 inch pipe to bottom ram to ram

d. Circulating out an influx while shut-in on 6-inch pipe

2.16 On a surface BOP stack, in which position must the valves on the kill line and choke line be placed during drilling?

a. Both types of valves closed on the kill line and opened on the choke line.

b. Manual valves closed and hydraulic valves opened.

c. Hydraulic valves closed and manual valves opened.

d. All valves must be closed.

e. All valves must be opened.

2.17 In which order should the valves for the choke line be installed on surface BOP with a 'rated working pressure' of 10,000 psi according to best practice? (Note: inside means closer to the BOP)

a. Inside - a hydraulically operated valve, middle - a manual valve, outside – a hydraulically operated valve.
b. Inside - a hydraulically operated valve, outside - a manual valve.
c. Inside - a manual valve, outside - a hydraulically operated valve.
d. Inside - a manual valve, middle - a check valve, outside - a hydraulically operated valve.
e. Inside - a check valve, middle - a hydraulically operated valve, outside – a hydraulically operated valve.

2.18 What is used to remotely operate valves on the choke line?

a. Air
b. Hydraulic Fluid
c. Nitrogen
d. Wires

2.19 How should the manually operated and hydraulically operated kill line valves on the BOP be pressure tested?

a. From the wellbore side, with the check valve installed.

b. From the pump side, with the check valve removed so that the pressure can be bled off.

c. From the well bore side, with the check valve removed and the kill line vented.

d. From the pump side, because the check valve on the outside of the valves prevents the detection of a faulty valve if they are pressure tested from the well bore side.

2.20 On the surface BOP stack there are hydraulically operated valve installed for the kill and chock lines on the BOP side outlet connections. Is it true that hydraulic valve is designed to close automatically if the hydraulic pressure in the hydraulic line to the valves is lost?

a. Yes

b. No.

2.21 What is the minimum RWP for a BOP to be classified as Class 4?

a. 5000 psi

b. 10,000 psi

c. 15,000 psi

2.22 A surface stack BOP consists of:
1 x 10000 psi rated annular preventer
1 x 10000 psi rated 5"pipe rams
1 x 10000 psi rated blind/shear rams
1 x 15000 psi rated drilling spool with 10000-psi rated remotely operated side outlet valves
1 x 10000 psi rated Variable Bore Pipe Rams
(The string is off bottom by 3000 ft.)
Which operation can you do keeping control of the Bottom Hole Pressure (BHP)?

a. Circulating out an influx while shut in on the lower pipe rams

b. Stripping 5-inch pipe to bottom ram to ram

c. Stripping 6 inch pipe to bottom ram to ram

d. Stripping back to bottom and bleeding mud from choke.

3 <u>BOP-Annular Preventers</u>

3.1 What pressure must be kept in the annular BOP closing chamber during stripping operation?

a. The minimum pressure of BOP closure that ensures proper sealing.

b. The minimum pressure that allows the tool joint to go through the packing.

c. 500 psi.

d. 300 psi less than the closing pressure of the ram operation.

3.2 What has to be checked before the installation of any annular packing element? *(Two answers)*

a. Maximum Anticipated Surface Temperature

b. Type of mud to be used.

c. Desired hydraulic closing pressure.

d. Maximum pipe outside diameter.

3.3 Drill pipe in the hole with float valve in string, the well is shut in on Annular. Which way you can make circulation?

a. Down the choke line, up the string

b. Down the drill string, up choke line

c. Down the drill string, up the kill line

d. Down the choke line, up kill line

3.4 What are annular preventer sealing elements designed to do?

a. To crush the casing

b. To hang off the drill string

c. To seal around any size of tubulars and seal off an empty well

d. To seal around any type of drilling equipment at rated pressure

3.5 During a pressure test of a surface stack annular preventer, the closing pressure must be increased to achieve a successful test. What could be happening?

a. Regulated annular pressure should always be increased for pressure test

b. The annular element material is not correct for the drilling fluid type in the well

c. The annular regulator is damaged, and should be repaired at the next casing point

d. The annular element is starting to deteriorate, and may need replaced soon

3.6 What is the maximum annular pressure reading on a 3000 psi hydraulic BOP control unit?

a. 1500

b. 900

c. 3000

d. 250

3.7 While tripping out of the hole, the wellbore pressure-assisted annular preventer is used to shut in a flowing well. You decide to strip back to bottom to perform the kill operation.

When should you adjust the closing pressure to manufacture's recommendations while maintain a seal?

a. Before shutting in the well

b. When the gas reaches the BOP stack

c. When the pumps reach the kill speed

d. When the shut in casing pressure stabilizes

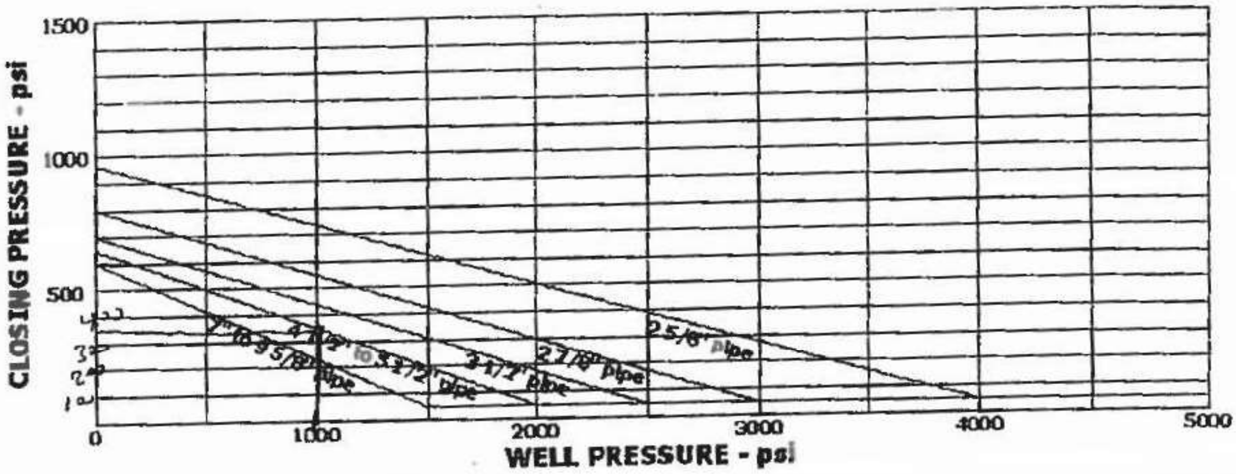
3.8 There is a 5" d/pipe in hole, the well surface pressure is 1000 psi, find out how much The closing pressure for 13 5/8" – 5000 psi. Annular preventer, Hydril, type "GK". (Guide lines to determine initial closing pressure for stripping operations with Hydril manufacture annular preventer).

a. 200 – 300 psi

b. 300 – 400 psi

c. 400 – 500

d. 500 psi or above



3.9 When annular BOP's are hydraulically pressure tested, test pressure may have to be charged up two or more times before an acceptable test is obtained.

What is the most likely reason?

a. Annular BOP's always leak at first.
b. The compressibility of the hydraulic fluid from the hydraulic control unit below the closing piston causes the test pressure to drop.
c. As a result of the applied hydraulic test pressure the packing unit elastomer is flowing into a new shape.

3.10 A BOP stack is made up from the well head as follows:

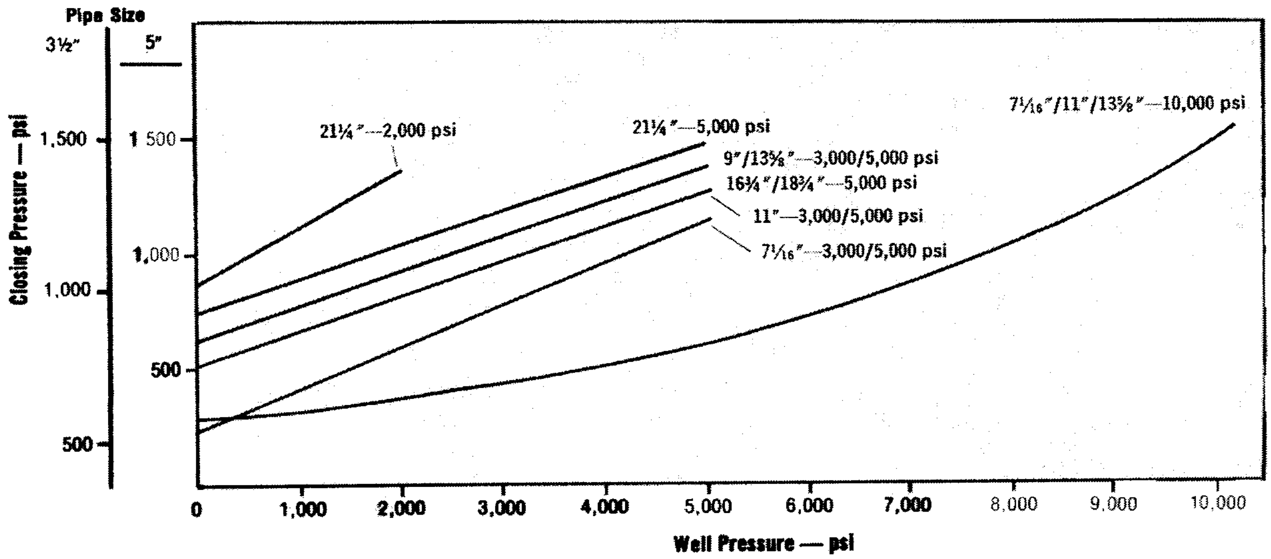
Three Ram BOPs, 13-5/8, 10,000 psi rated working pressure.

One Annular BOP, 13-5/8, 5,000 psi rated working pressure.

After taking a kick while tripping the well is closed in on 5 inch pipe using the Annular Preventer. After stabilization of shut in pressures the casing gauge reads 1,000 psi.

Using the diagram below what hydraulic pressure should the annular closing pressure be adjusted to for stripping?

GUIDELINES TO DETERMINE INITIAL CLOSING PRESSURES FOR STRIPPING OPERATIONS



a. 200 - 400 psi.
b. 400-600 psi.
c. 600 - 800 psi.
d. 1000-1500 psi

3.11 Which type of annular BOP was designed with a weep hole?

a. Cameron Model D

b. Hydril Model GL

c. Shafer Model Wedge cover

d. Hydril Model MSP

3.12 Which type of rubber element should be used for Oil Base Mud At low temperature?

a. Natural rubber

b. Nitrile

c. Neoprene

3.13 How to know if an annular packing element is deteriorated? ***(Three answers)***

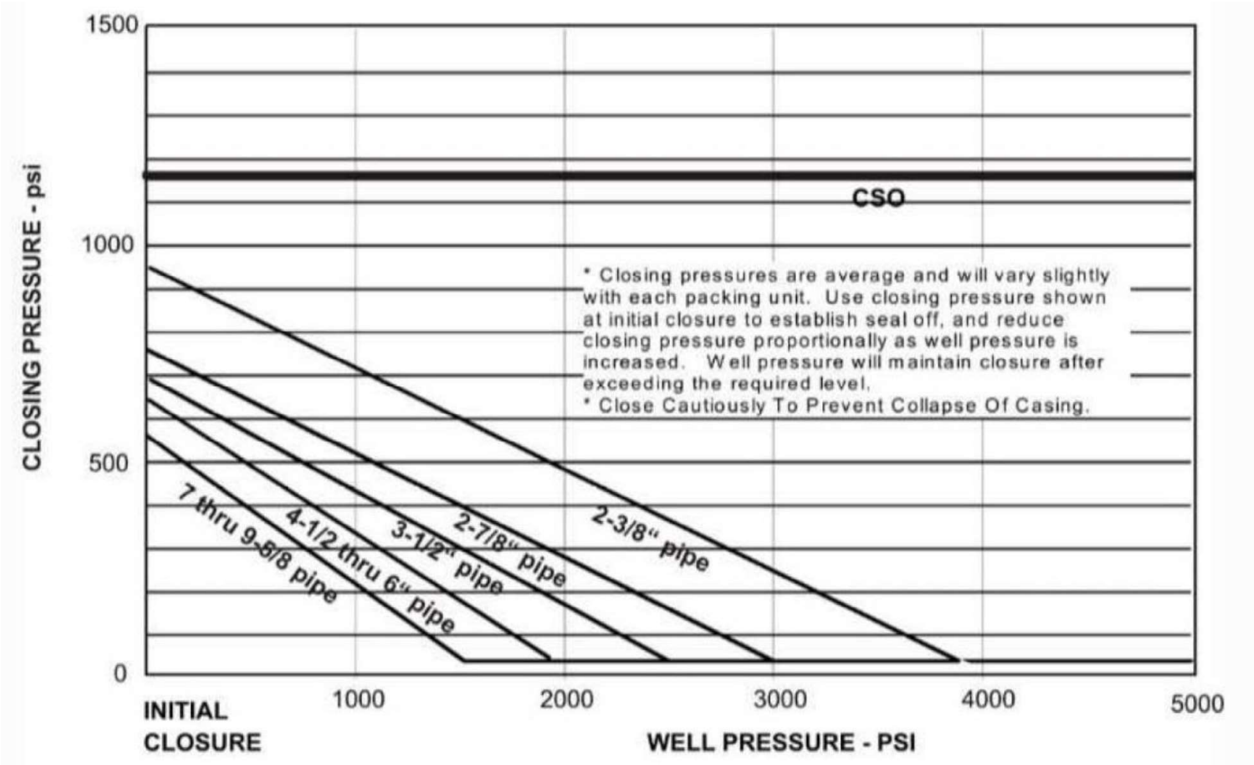
a. Closing pressure required to make effective seal increases every test.

b. Having to increase the annular closing pressure above than standard.

c. Having to increase the pressure after closing in the annular. (up to standard pressure)

d. Finding rubber pieces with mud returns at shale shakers.

3.14 Which of the following answers are right while having 1000 psi SICP for *(Three answers)*

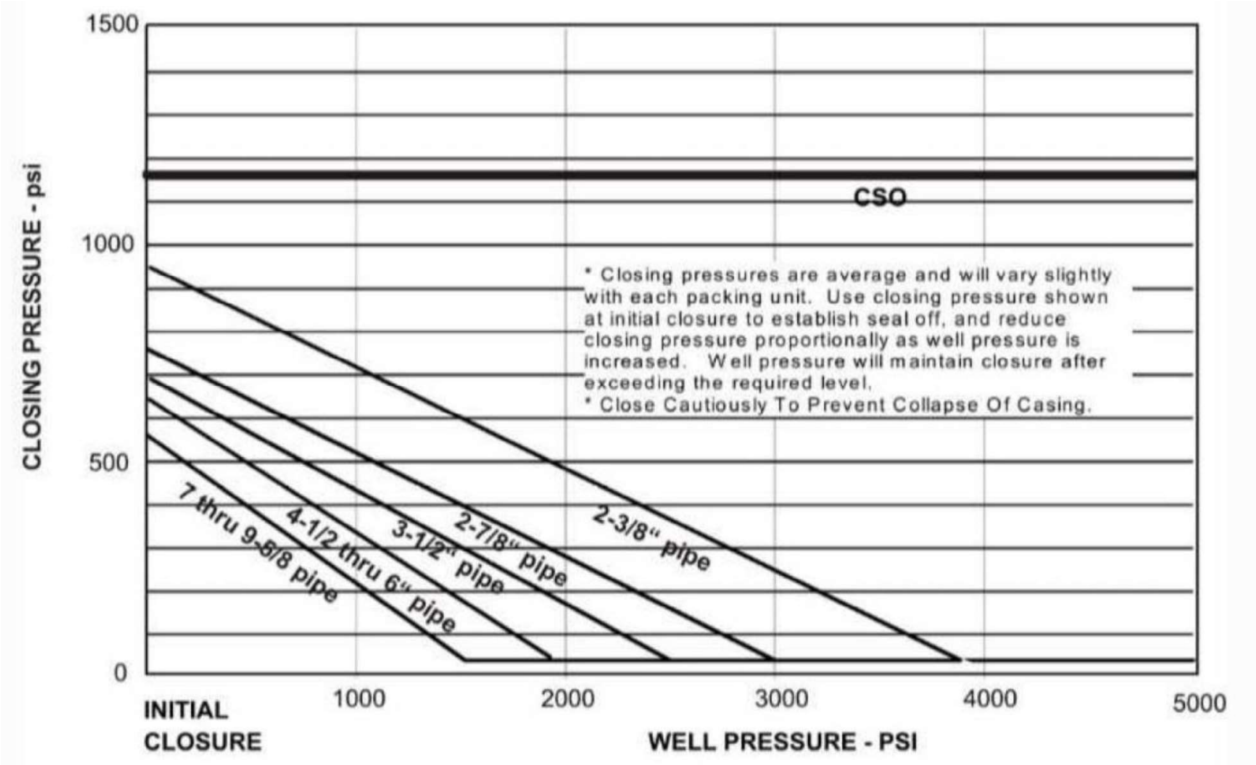


a. 1100-1200 closing pressure is suitable to close on EMPTY WELL (CSO)
b. 300-400 closing pressure is suitable to close on 5 inch drill pipe.
c. 500-600 Closing pressure is suitable to close on 2 7/8 inch drill pipe.
d. 300-400 closing pressure is suitable to close on 3 1/2 inch drill pipe.

3.15 A wellbore pressure-assisted annular preventer in the BOP stack. The manufacturer recommends the closing pressure of 600 PSI for the pipe size being used. When should you adjust the closing pressure to manufacture's recommendations?

a. Before shutting in the well
b. When the gas reaches the BOP stack
c. When the pumps reach the kill speed
d. When the shut in casing pressure stabilizes

3.16 Which of the following answers is correct for well bore assisted annular preventer?



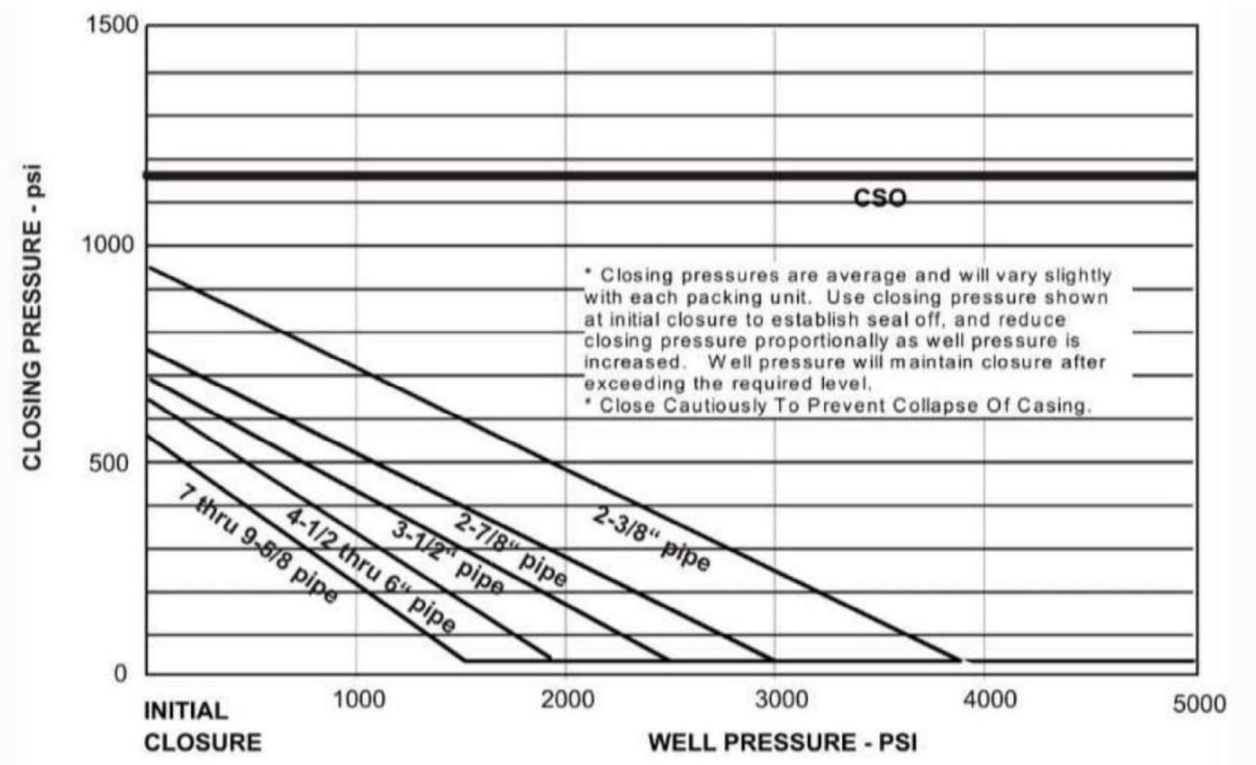
a. 300 – 400 closing pressure is suitable to close on 2-7/8” pipe

b. 200 – 300 closing pressure is suitable to close on 5 inch drill pipe.

c. 1100 – 1200 closing pressure is suitable to close on EMPTY WELL (CSO)

d. 700 – 800 closing pressure is suitable to close on 3 1/2 inch drill pipe.

3.17 What is the closing pressure range while drilling for the following well bore assisted annular preventer?



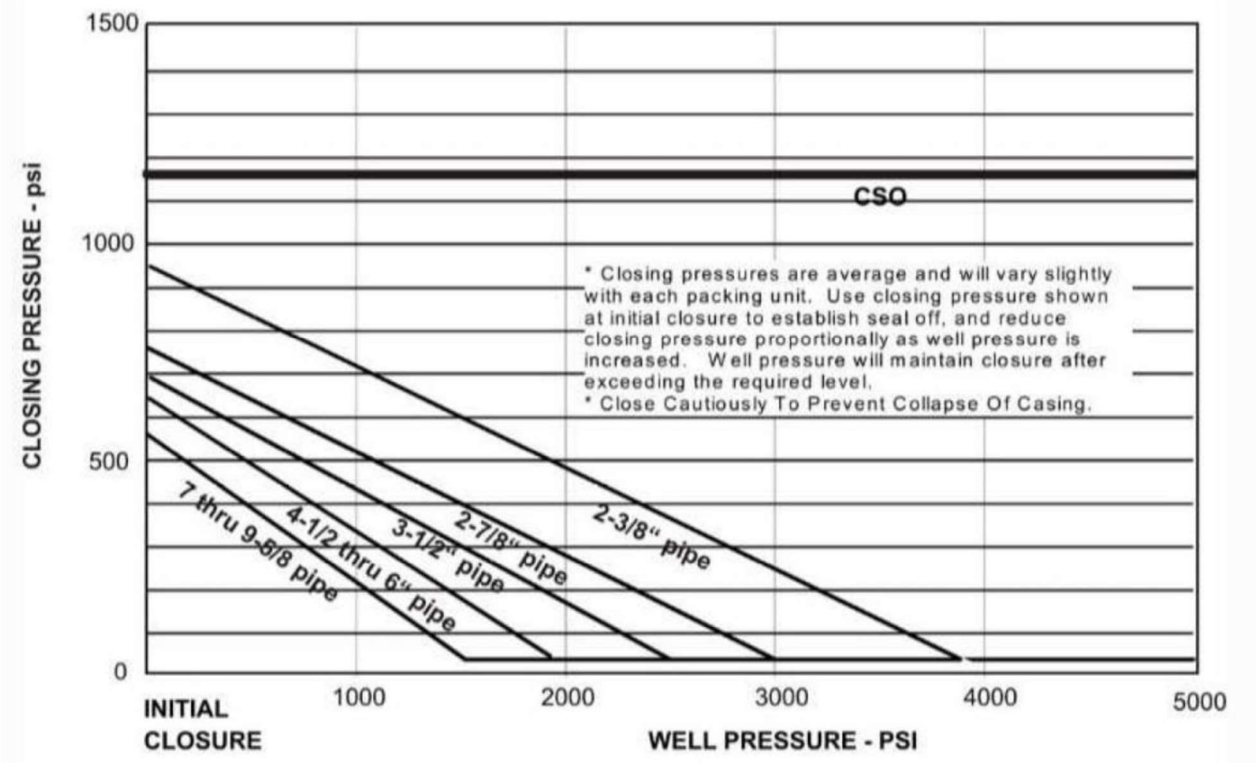
a. 500 – 1500 psi

b. 550 – 1200 psi

c. 300 – 1100 psi

d. 1000 – 1200 psi

3.18 Which of the following answers is correct for well bore assisted annular preventer 10000 psi RWP?



a. 800 – 900 psi closing pressure is suitable to close on 500 psi well-bore pressure with a 2-3/8" pipe in the hole

b. 200 – 300 psi closing pressure is suitable to close on 500 psi well-bore pressure with a 5 inch drill pipe in the hole

c. 1100 psi closing pressure is suitable to close on 500 psi well-bore pressure for an EMPTY WELL (CSO)

d. 700 – 800 psi closing pressure is suitable to close on 500 psi well-bore pressure with a 3 1/2 inch drill pipe in the hole

4 BOP-Ram Preventers

4.1 Sometimes it is required to increase the closing pressure of BOP Ram to perform an effective seal

a. High formation pressure need more closing pressure to perform effective seal

b. This force the feed-able rubber to compensate for deteriorated rubber element.

c. It depends on pipe size

d. Increasing pressure will help Mud Gas Separator to provide more effective separation

4.2 The closing ratio can be defined as: ***(Two answers)***

a. The ratio between the ram piston area, to the ram shaft area.

b. The ratio between hydraulic system pressure to hydraulic ram closing pressure

c. The ratio between wellbore pressure, to the closing pressure.

d. The ratio between ram piston area to BOP bore size

4.3 The BOP stack consists of the following components:

Top Ram: 5'' fixed pipe Ram

Middle Ram: 5''-61/2 Variable pipe ram

Bottom Ram: 5'' Fixed pipe ram

Choose from the following, the correct combination of rams to perform ram to ram stripping:

a. Top pipe ram and Bottom pipe ram.

b. Middle pipe ram and Bottom pipe ram.

c. Top pipe ram and Middle pipe ram.

4.4 What is the main purpose of the weep hole on ram type BOPs?

a. It allows installation of a grease nipple so that the ram shaft can be greased

b. It prevents leaking trough the ram shaft packing from the well bore to the hydraulic opening chamber

c. It allows an inspection of the ram shaft, and should be plugged with a bull plug after inspection

d. The weep hole prevents leakage from hydraulic opening chamber to the hydraulic closing chamber

4.5 The force required to shear the pipe can be greater than the force required for a pipe ram to seal around drill pipe.
What are the main design features of a shear ram that create the required shearing force?

a. The length of piston stroke and closing pressure

b. The ram rod diameter and closing pressure

c. The shear ram closing ratio and closing pressure

d. The shear ram opening ratio and opening pressure

4.6 What is a locking device on a ram-type preventer designed to do?

a. Allows the ram to close around the pipe

b. Locks the manifold pressure so it cannot be changed

c. Prevent accidental operation of the ram

d. Prevents the ram from opening

4.7 What is the advantage of a self-adjusting ram lock?

a. As the ram rubber wears, the closing pressure can be reduced to minimize further wear

b. As the ram rubber wears, the lock position changes to maintain a seal around the pipe

c. The ram closes quickly to minimize the size of the influx

d. The ram piston moves the same distance each time the ram is operated

4.8 When casing rams would be installed in a surface BOP?

a. Before pulling the Bottom Hole Assembly (BHA).

b. When the bit is at the shoe while tripping out the string.

c. While rigging up to run casing.

d. While running electric logs.

4.9 Which drilling operation may require the BOP pipe rams to be changed?

a. Before a fishing operation

b. Before a side-track

c. Before coring

d. Before running casing

4.10 During a well control operation with the middle pipe rams closed and shut in against 4000 psi. It is decided to strip the tool joint through the middle pipe rams.

Ram type BOP data:

RATED WORKING PRESSURE, 15000 psi.

NOMINAL SIZE, 7 1/16 inch

CLOSING RATIO, 6.9

OPENING RATIO, 2.2

What is the Driller's next step?

a. Close the bottom rams and bleed off the pressure from above.

b. Initially, close the upper pipe rams above the tool joint. Then activate the By-pass function on the BOP panel to get sufficient opening pressure from the accumulators. Then open the middle pipe rams.

c. Initially, close the upper pipe rams above the tool joint. Then open the middle pipe rams.

d. Initially, close the upper pipe rams above the tool joint. Then pump in 4000 psi pressure between the middle pipe rams and the upper pipe rams. Then open the middle pipe ram.

4.11 What is the main purpose of Blind/Shear rams?

a. To shear tubular like drill pipe while simultaneously sealing the hole.

b. To shear tubular like drill pipe without sealing the hole.

c. To effect a seal with drill collars in the hole.

4.12 Are all ram type BOPs designed to open in a situation where Rated Working Pressure is contained below the rams and mud hydrostatic pressure to the flow line is above the rams, e.g. in a stripping operation?

a. Yes.

b. No.

4.13 Which ram type preventer on a Cameron 13-5/8, 10,000 psi BOP stack is equipped with thicker intermediate flanges?

a. Pipe rams.

b. Blind rams.

c. Shear rams.

d. Variable rams

4.14 In an emergency situation it is possible to activate a ''secondary seal'' on a ram type preventer. Which one of the following pressures will seal against?

a. The wellbore side

b. The opening chamber side

c. The closing chamber side

4.15 Which of the following statements about fixed ram type BOP are correct *(Three answers)*

a. Ram types BOP are designed to contain and seal rated working pressure from above the closed rams as well as from below.

b. Ram type BOP should be equipped with a mechanical locking system.

c. Fixed bore ram type BOP can close and seal on various pipe sizes.

d. Fixed bore ram type BOP can be used to hang off the drill string.

e. Ram type BOPs are designed to contain and seal rated working pressure only from below the closed rams.

4.16 Which of the following rams will be able to close on a wellbore pressure of 15,000 psi with the normal closing pressure of 1500 Psi on the manifold?

a. Top fixed ram with Closing ratio of 7:1

b. Bottom Variable ram with a closing ratio of 10:1

c. The middle fixed ram with closing ration of 5:1

4.17 Surface Pressure = 10,800 psi

Closing Ratio: 7:1

Ram piston friction = 300 psi

What is the minimum ram closing pressure?

a. 1500

b. 1550

c. 1850

d. 3000

5 <u>BOP-Test</u>

5.1 What must you do if a well barrier element fails a pressure test?

a. You must document problems with the BOP equipment and the actions you took to correct the problem.

b. You don't retest a well barrier element that fails the initial test if you have correctly identified & corrected the problems.

c. You don't need to document any problems w/BOP equipment if you get a successful test after you have corrected them.

d. You should only document successful pressure tests on your BOP equipment but you should only do so if the work first.

5.2 After pressure testing BOP, pressure have to be bled through

a. Needle valve

b. Manual Gate

5.3 Why should the side outlet valves below the test plug be kept in the open position while testing a surface BOP stack? *(Two answers)*

a. Because the test will create extreme hook load

b. If not kept open, reverse circulation will be needed to release the plug

c. To check the position of the test plug

d. To monitor the annulus for plug leakage

e. To prevent potential damage to the casing or formation

5.4 When testing the BOP stack with a test plug or cup type tester, why is pressure communication maintained from below the two to atmosphere?

a. Otherwise reverse circulation will be needed to release the tool.

b. To avoid potential damage to the casing/open hole.

c. To avoid swabbing a kick during the test

d. To avoid the creation of extreme hook load

5.5 Under what circumstances a "CUP-TYPE" tester would be used in preference to a "TEST-PLUG" when testing a surface BOP stack.

a. There is no difference, they are interchangeable.

b. When you require to test entire casing head, outlets and casing to wellhead seals.

c. To test stack without applying excess pressure to wellhead and casing.

5.6 The body of a new BOP is given a hydrostatic body or shell test after manufactured. If the BOP has a Rated Working Pressure of 15000 psi, what hydrostatic body test pressure is required according to API recommendations?

a. 15000 psi.

b. 17500 psi.

c. 20000 psi.

d. 22500 psi.

5.7 How often should all operational components of the surface BOP stack equipment systems be function tested according to API RP53?

a. Only after the installation of the BOP stack.

b. At least once a week.

c. Once per shift.

5.8 What is the suitable pressure and frequency for testing stab in valves? *(Two answers)*

a. Same pressure value for testing BOP.

b. Same frequency of BOP tests.

c. Every 4 weeks

d. To the pressure of the MAASP

5.9 To what pressure should the Stab in valve be tested to for subsequent test?

a. Maximum Anticipated Surface Pressure. (MASP)

b. 70% RWP of annular.

c. 100% Ram type BOP.

5.10 What is the suitable RWP for a test pump for testing a 15K BOP stack?

a. 20,000 psi

b. 10,000 psi

c. 15,000 psi

5.11 After performing a drawdown test, Pressure on the accumulator gauge went down to 1160 psi (not 1200) and after 15 minutes of waiting the pressure built up above 1200.

a. Test is accepted

b. Test must be repeated

c. Test Failed.

5.12 After Pressure testing the kill line from the well bore side with test plug installed, how can the test pressure be bled?

a. Through the test pump needle valve. (Since the check valve is removed during testing)

b. Through the manual choke valve.

c. Through the remotely operated choke valve.

5.13 A draw Down Test is performed with the below outcomes.

Which function of the BOP 13 5/8 5000 PSI is not accepted *(Two answers)*

	Closing Pressure	Annular	Top Ram	Middle Ram	Lower Ram
A	500	Time to close 39 sec			
B	1500		Time to close 23 sec		
C	1500			Time to close 37 sec	
D	1500				Time to close 27 sec

5.14 After performing a draw down test which of the following is considered an acceptable draw down test.

a. Close all ram and annular, open one HCR, the remaining pressure on the accumulator gauge is 1250 and time to close ram is 39 sec.

b. Close all ram and annular, open one HCR, the remaining pressure is 1050 and the time to close ram is 23 min.

c. Close all ram and annular, open one HCR, the remaining pressure is 1200 and time to close ram is 28 sec.

5.15 While testing the BOP, the bonnet is leaking. Which action is needed?

a. The bonnet seal is leaking, repair immediately

b. The ram shaft seal is leaking, repair immediately.

c. No problem, schedule the repair to the next maintenance.

d. No action is required.

5.16 What is the indication that the rubber of Cup Type Tester is leaking?

a. Test pump pressure reaches maximum value

b. There is flow from drill pipe

c. There is flow from kill line

d. There is flow annulus vent

5.17 The BOP test pump is connected to the kill line on a surface stack. A plug type tester is in position and connected to the drill pipe. How can you tell if the test plug is leaking?

a. Check for a pressure increase at the manual choke.

b. Check if the test pump can reach the required pressure

c. Monitor for flow back up the drill string

d. Open the choke line valves through the Mud Gas Separator

5.18 What is the test pressure for IBOP during initial pressure test?

a. Maximum anticipated surface pressure (MASP)

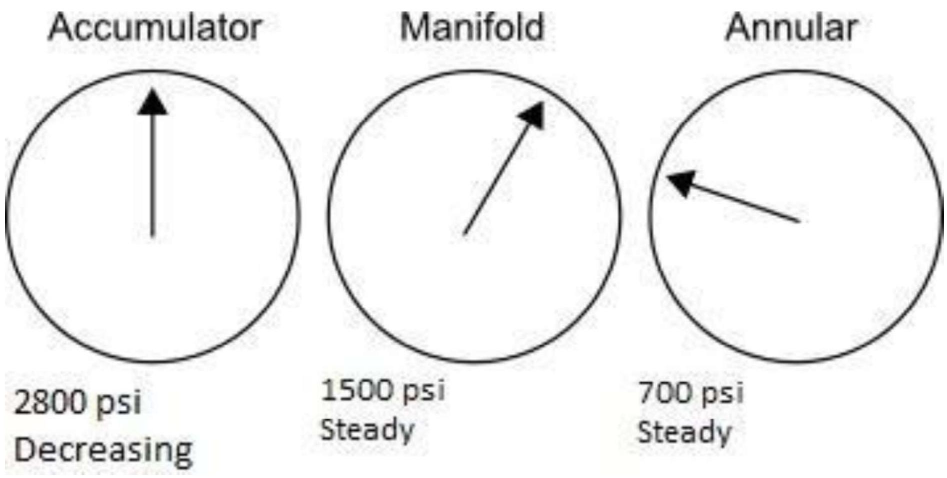
b. Rated working pressure (RWP)

c. 70% of RWP

d. Maximum mud pump pressure

6 BOP-Control Systems

6.1 You are drilling ahead and the gauges on your BOP accumulator control system reads as follows: (the BOP has not been operated)



What is the likely reason for the change?

a. Everything is OK.

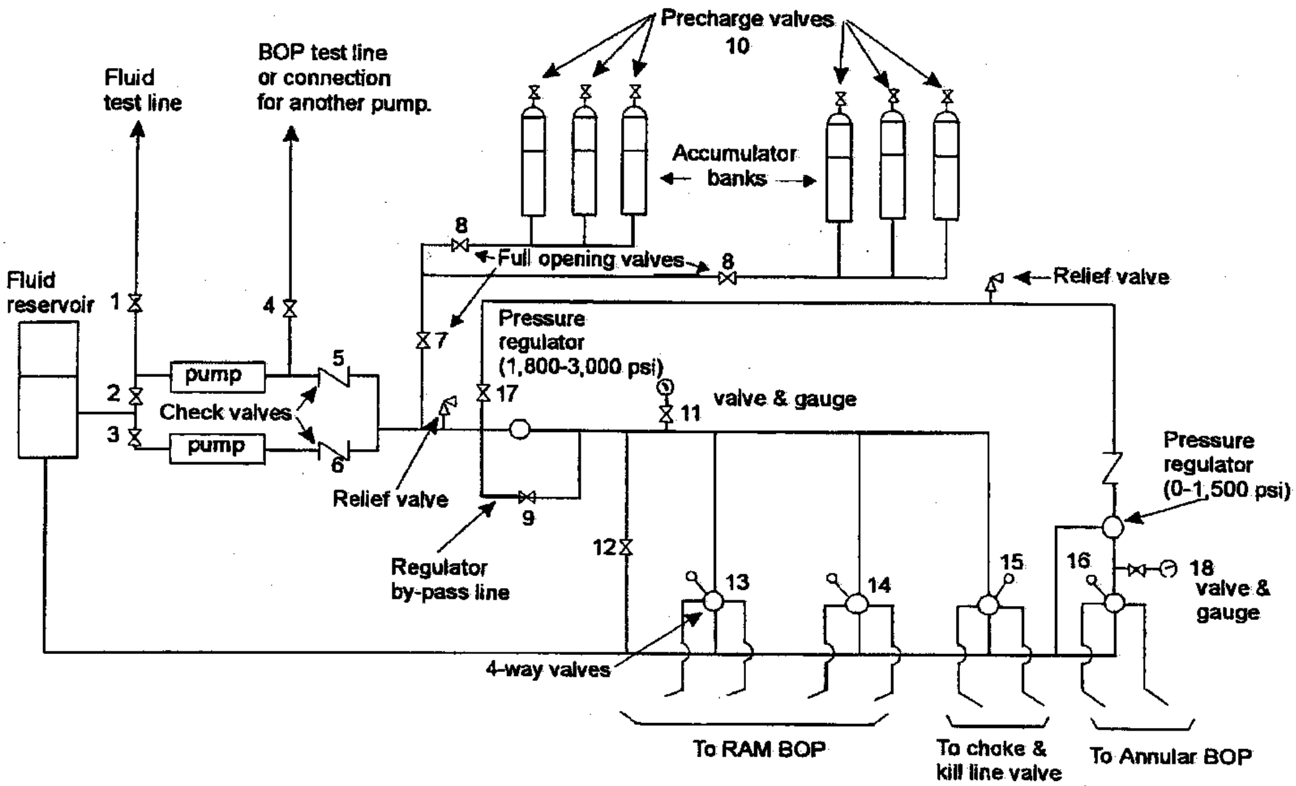
b. There is a leak in the hydraulic system.

c. There is a malfunction in the remote panel master switch/handle.

d. There is a malfunction in the manifold hydraulic regulator.

e. Electric motor stop/start switch is faulty.

6.2 Figure below illustrates a hydraulic control schematic for a BOP Control System.



I. Select the list below that indicates the valves that should be open while drilling

a. Valves; 2, 3, 5, 6, 7, 8, 11, 13, 14, 16, 17, 18.

b. Valves; 1, 3, 5, 7, 8, 10, 11, 14, 15, 17, 18.

c. Valves; 2, 3, 4, 7, 9, 10, 12, 13, 15, 16, 18.

d. Valves; 1, 2, 4, 5, 7, 8, 9, 11, 12, 14, 17.

II. Select the list below that indicates the valves that should be closed while drilling

a. Valves; 1, 4, 9, 10, 12, 15.

b. Valves; 2, 4, 8, 10, 11, 15, 17.

c. Valves; 3, 5, 7, 9, 13, 16, 18.

d. Valves; 3, 4, 6, 9, 11, 16, 17.

6.3 What is the normal accumulator pressure reading on a 3000 psi Hydraulic Control Unit?

a. 2500 psi

b. 1500 psi

c. 3000 psi

d. 1000 psi

6.4 What is the first action should be taken after connecting the open and close hydraulic lines to the surface installed BOP stack?

a. Drain the accumulator cylinders and check the nitrogen pre-charge pressure.

b. Function test all items on the stack

c. Place all functions in neutral position and start pressure testing the BOP stack.

d. Perform accumulator unit pump capacity test.

6.5 The well has just been shut in using the upper pipe ram.
The flow meter reads 7.2 gallons
The accumulator pressure has returned to 3000 psi
The manifold pressure has returned to 1500 psi.

Function	Volume to close (gallons)	Volume to open (gallons)
Annular	43	35
Top Ram	12.5	12.5
Lower Ram	12.5	12.5
Choke HCR	2.1	2.1
Kill HCR	2.1	2.1

Using the data in the table, has the BOP operated successfully?

a. No, the flow meter value is correct but manifold pressure is too low

b. No, the flow meter value is incorrect

c. Yes, all pressures values are correct

d. Yes, the flow meter value is correct

6.6 While drilling, what is the normal hydraulic pressure in the ram opening lines between the BOP hydraulic control unit and the BOP stack?

a. 0 psi

b. 1500 psi

c. 3000 psi

d. 500 psi

6.7 When operating a stack function from the remote BOP panel on a surface BOP installation, the close light does not illuminate and the manifold pressure does not drop. Which malfunction does this indicate?

a. The 3 position-4 way valve on the hydraulic BOP control unit failed to shift

b. The hydraulic closing line to the BOP is plugged

c. The close function light bulb has blown

d. There is a leak in the hydraulic line to the BOP

6.8 After a drilling break, the driller does a flow check. The well is flowing, and the upper pipe ram close function is activated. The driller notes and reports the following pressures:

Accumulator pressure is 3000 psi

Annular pressure is 500 psi

Manifold pressure is 0 psi

a. The 'manifold pressure reducing and regulating valve' is malfunctioning

b. The hydraulic line to the upper pipe ram is blocked

c. The selector valve is stuck in the open position

d. There is a leak in the hydraulic line to the upper pipe ram.

6.9 Annular 13 inch x 5000 psi (10K) BOP stack, the regulated manifold pressure is 1500 psi, and the regulated annular pressure is 1000 psi. What would tell you that the ram has closed correctly?

a. The annular light should change from 'open' to 'close' and 43 seconds later the annular pressure should read 1000 psi.

b. The annular light should change from 'open' to 'close' and 43 seconds later the manifold pressure should read 1500 psi.

c. The ram light should change from 'open' to 'close' and 23 seconds later the manifold pressure should read 1000 psi.

d. The ram light should change from 'open' to 'close' and 23 seconds later the manifold pressure should read 1500 psi.

6.10 You are supervising the weekly BOP function test on a surface 18 ¾ inch x 10000-psi (10K) BOP Stack. The regulated manifold pressure is 1500 psi and regulated annular pressure is 1000 psi.
What would tell you that the annular has closed correctly?

a. The annular light should change from 'open' to 'close', and 60 seconds later the annular pressure should read 1000 psi.

b. The ram light should change from 'open' to 'close' and 23 seconds later the manifold pressure should read 1000 psi.

c. The ram light should change from 'open' to 'close', and 23 seconds later the manifold pressure should read 1500 psi

d. The annular light should change from 'open' to 'close', and 43 seconds later the annular pressure should read 1000 psi

6.11 The driller activates a ram close function from the remote BOP panel on a surface BOP installation. The manifold pressure continues to drop and did not rise back up again.

What is the reason for this?

a. The 3-position/4-way valve on the hydraulic BOP control unit failed to operate

b. The hydraulic closing line to the BOP is plugged

c. The light bulb has blown

d. There is a leak in the hydraulic line to the BOP

6.12 You are closing a pipe ram from the remote panel on a surface BOP

The close light illuminated and the manifold pressure gauge initially drops and then returns to normal

What is the cause of this change manifold pressure?

a. A pilot signal is being sent to the accumulator charge pumps

b. The accumulator 4-way valve has shifted to the 'neutral' position

c. Fluid is flowing into the pipe ram closing chamber

d. Fluid is flowing into the pipe ram opening chamber

6.13 In a well control situation with a multi ram stack (ASPP), the annular BOP has a severe leak, The Driller activates the upper pipe ram close function and sees that the manifold pressure immediately decrease to zero. The accumulator pressure decreases and the charge pumps activate.

Which action is required to shut in the well as quickly as possible?

a. Activate the by-pass function.
b. Close the ram manually by using the ram lock screws.
c. Place the upper pipe ram in the open position, and then close the lower pipe ram.
d. Send the Assistant Driller to manually operate the stuck selector valve.

6.14 In a well control situation with a single ram BOP stack, the annular has a severe leak. The Driller activates the pipe ram close function, and sees that the manifold pressure immediately decreases to zero. The accumulator pressure decreases and the charge pumps activate.

Which action is required to shut the well as quickly as possible?

a. Activate the bypass function.
b. Close the ram manually by using the ram lock screws.
c. Send the assistant driller to manually operate the stuck selector valve.
d. Use the hammer to release the stuck manifold pressure reducing and regulating valve.

6.15 Which function on a BOP stack is operated from the annular pressure regulator?

a. Annular preventer and hydraulically operated choke and kill line valves
b. Annular preventer only
c. Ram preventer, annular preventer and hydraulically operated choke and kill line valve
d. Rams and hydraulically operated choke and kill line valves

6.16 What is the function of the master control valve on the remote BOP control panel on the rig floor?

a. To allow pressuring up of the 4-way valves on the hydraulic control unit.
b. To activate the open or close lights.
c. To activate power to the control unit charge pumps.
d. To allow pressuring up of the control valves on the remote BOP control panel.

6.17 Given the volumes below, how much hydraulic fluid is required to complete the following operations (no safety margin)?

Operations	Close then Open
Equipment	One Annular Preventer
	Two Pipe Rams
Volumes:	
Annular Preventer	51 gallons to close, 45 gallons to open
Pipe Ram	25 gallons to close, 22 gallons to open

a. 143 gallons

b. 152 gallons

c. 190 gallons

d. 95 gallons

6.18 When shutting in the well at the BOP Panel, a problem may occur that causes doubt about whether the selected function has operated.

What has happened if the light illuminates but the pressure gauge does not drop?

a. The 4-way valve on hydraulic closing unit failed to shift.

b. The hydraulic closing line to the BOP is plugged.

c. There is a leak in the hydraulic line to the BOP.

d. The bulb has blown.

6.19 On the driller's pneumatically operated panel for a surface installed BOP, a ram close function was activated and the following observations were made:

The light changes from green to red

Annular pressure did not change.

Manifold pressure did not change.

Accumulator pressure did not change.

What is the probable cause of the problem?

a. The selector valve (3 position/4 way valve) is stuck in the open position.

b. There is a leak in the hydraulic line connecting the BOP to the BOP control unit.

c. Electric pressure switches are malfunctioning.

d. The pumps on the BOP control unit are malfunctioning.

e. There is a blockage in the hydraulic line connecting the BOP to the control unit.

6.20 The below shows a set of remote control panel gauge readings. The BOP has not been operated and the BOP accumulator charge pumps (electric and air) are not running. What is the problem with these gauge pressures?

Accumulator pressure:	**2500 psi constant**
Manifold pressure:	**1500 psi constant**
Annular pressure:	**700 psi constant**

a. The accumulator pressure is too low.

b. The annular pressure is too low.

c. The manifold pressure is too high.

d. There is no problem. These gauge pressures are normal.

6.21 The below shows a set of remote control panel gauge readings. The BOP has not been operated and the BOP accumulator charge pumps (electric and air) are not running. What are the possible reasons for the low accumulator pressure readings? *(Two answers)*

Accumulator pressure:	**2500 psi decreasing**
Manifold pressure:	**1500 psi constant**
Annular pressure:	**700 psi constant**

a. The accumulator charge pump pressure switches have failed

b. The accumulator pre-charge pressure is too high

c. The accumulator pre-charge pressure is too low

d. There is a leak at the BOP

e. There is a leak in the hydraulic accumulator unit

6.22 The below shows a set of remote control panel gauge readings. The BOP has not been operated and the BOP accumulator charge pumps (electric and air) are not running. What do these gauge reading indicate?

Accumulator pressure:	**2900 psi Slowly Decreasing**
Manifold pressure:	**1800 psi increasing**
Annular pressure:	**700 psi constant**

a. The hydraulic circuit is leaking

b. There is a problem with the automatic hydro-electric pressure switch

c. There is a problem with the hydraulic pressure regulating valve

d. These pressure reading are within the normal range

6.23 On the remote BOP control panel on the rig floor, the master control valve allows air pressure to go to each function in preparation for operating the handle/button.

a. True.

b. False.

6.24 What is the usable fluid volume of an accumulator bottle, according to API requirements?

a. The total volume to be stored in the accumulator bottle.

b. The volume of fluid recoverable from an accumulator bottle, between the accumulator operating pressure and 200 psi above the bottle pre-charge pressure.

c. The volume of fluid recoverable from an accumulator bottle, between the accumulator operating pressure minus 200 psi and pre-charge pressure.

6.25 What happens when the handle on the BOP remote control panel is activated to close the upper ram preventer? (The master valve has been operated)

a. The handle opens the hydraulic valve in the back of the remote control panel and hydraulic fluid flows to the preventer.

b. The handle operates an electric switch in the back of the remote panel. The electric current operates the hydraulic valve at the accumulator unit and this enables the hydraulic fluid to flow to the preventer.

c. The handle operates an air valve in the back of the remote panel. The air activates a piston at the accumulator unit that operates the 4-way valve enabling the flow of hydraulic fluid to the preventer.

6.26 How would you correctly activate a BOP function from the Driller's remote panel on the surface BOP stack installation?

a. Push the BOP function button and then release it. Then push the master button

b. Push the master button for five seconds, and then release before pushing a BOP function button.

c. Push the master button while a BOP function button is pushed.

d. Push the BOP function button and then release it.

6.27 For which ram operation, would the by-pass valve on a surface hydraulic BOP control unit be used?

a. 3-1/2 inch pipe rams

b. 5 inch pipe rams

c. Blind/shear rams

d. Variable bore rams

6.28 Which gauges on the remote BOP control panel would show a reduction in hydraulic pressure when the annular preventer is close? *(Two answers)*

a. The accumulator pressure gauge
b. The air pressure gauge
c. The annular pressure gauge
d. The cement line pressure gauge
e. The manifold pressure gauge

6.29 Which gauges on the remote BOP control panel would show a reduction in hydraulic pressure when the blind/shear ram is closed? *(Two answers)*

a. The accumulator pressure gauge
b. The air pressure gauge
c. The annular pressure gauge
d. The cement line pressure gauge
e. The manifold pressure gauge

6.30 The air pressure gauge on an air operated remote BOP control panel reads zero. Which BOP functions can still be operated?

a. All functions can be operated.
b. No function can be operated.
c. The annular preventer.
d. The choke and kill line valves.

6.31 If the manifold gauge on the remote BOP control panel reads zero and the other gauges read normal values, which BOP function can be operated?

a. All stack functions
b. No stack function
c. The annular preventer
d. The ram preventers

6.32 The driller closes the upper rams from the remote control panel. The green light indicator turns off and the red light indicator does not turn on. The accumulator pressure and the manifold pressure readings decrease and then return to normal. What could be the cause of this malfunction?

a. The 3-position/4-way valves on the hydraulic BOP control unit did not move
b. The rams did not close
c. There is a leakage on the hydraulic circuit
d. There is an electrical fault with the lights

6.33 On a surface BOP installation, the Driller simultaneously pushes the "Master" and "choke open" buttons on the remote panel and the lights change colour.

What do the changing lights confirm?

a. The panel has correctly functioned and hydraulic opening pressure is applied to the choke line valve

b. The panel has correctly functioned and the choke line valve is now open

c. The panel has functioned correctly and the choke line valve is now closed

d. The panel has not functioned correctly, but the choke line valve is now open.

6.34 Where are the electric pressure (activation) switches for the remote BOP control panel lights located?

a. Inside the BOP operating chambers

b. On the hydraulic BOP control unit

c. On the pressure gauge on the remote control panel

d. On the remote control panel operating handles

6.35 What is the normal manifold pressure gauge reading on a 3000 psi hydraulic BOP control unit?

a. 1000 psi

b. 1500 psi

c. 2500 psi

d. 3000 psi

6.36 Why is a master control valve fitted to the remote BOP control panel on the rig floor?

a. To activate power to the control unit charge pumps

b. To activate the open or close lights

c. To adjust pipe ram closing pressure

d. To ensure that all BOP functions are "two hand "operated from the Driller's remote panel

7 <u>Test Charts and Documents</u>

7.1 What must be true for barrier test charts and documents? ***(Two answers)***

a. The test documents should record the test pressure and its duration

b. The test documents should record the type of test to be conducted

c. The test documents will not require a signature of an authorized person

d. The test documents must be signed by authorized person and the chart destroyed after the test.

7.2 What are the key requirements of a barrier test document? ***(Two answers)***

a. All barrier test documents can be destroyed after a successful test

b. All barrier test documents must be signed by an authorized person

c. All test documents must be retained at head office for a period of six months

d. Barrier test pressures must be recorded

e. If there is a successful function test, there is no need for pressure test documentation

7.3 Who should sign the pressure test documentation?

a. The Driller, the Tool Pusher, and the Cement Pump Operator.

b. The Mechanic, the Drilling Contractor Representative, and the BOP Engineer.

c. The Mechanic, the installation/rig manager, and the Electrician.

d. The Pump Operator, the Drilling Contactor Representative, and the Well Operator Representative.

8 <u>Inflow Test</u>

8.1 What is the purpose of an inflow test?

a. To check for communication between the choke manifold and a surface BOP stack.

b. To check the integrity of the casing strings and surface equipment before drilling out the float collar and shoe.

c. The check the integrity of the formation and surface equipment before running a string of casing.

d. To check there is no communication from the formation through the casing, a liner lap cement plug.

8.2 What is the inflow test?

a. To test barrier element in the direction of flow when positive pressure upstream the barrier can't be applied

b. To circulate from drill string and take return from annulus

c. To check if barrier flowing when you applied negative pressure on the bottom.

8.3 In which situation, would you choose to do an inflow test to verify a well barrier element?

a. When pressure testing a liner lap.

b. When pressure testing the annular preventer

c. When pressure testing the choke manifold valve upstream of the remote choke

d. When pressure testing the top-drive inside Blowout Preventer (IBOP)

8.4 Performing an Inflow test with retrievable packer set above top of liner and the return is lined up to the trip tank after displacing the drill string to fresh water, while keeping original mud in the annulus. After the initial Pressure built, pressure was bleed. Soon after, an increase on SIDP is witnessed with no increase on the trip tank. What happened?

a. Bleed-off test (Bleed of pressure gradually) must be performed to check if it is a kick or trapped pressure due to thermal expansions.

b. Liner is leaking.

c. Thermal expansion of mud.

d. Packer is leaking.

9 <u>Choke</u>

9.1 For adjustable remote chokes as API, Do we need to conduct low and high pressure test initial and subsequent??

a. Yes

b. No

9.2 In the ‘’soft closed shut in arrangement’’ the adjustable choke valve should be

a. Opened

b. Half opened

c. Closed

d. Half closed

9.3 What checks should you do when testing the remote chokes to API Standard 53?

a. Function test both primary and secondary (back-up) control systems

b. Function test the primary control system only

c. Function test the primary control system. Then test the backup system at next test

d. Only function test at the API ‘Initial’ test

9.4 Why are two chokes incorporated into most choke manifold?

a. To allow a kick to be circulated out at a higher flow rate.

b. To provide backup if there is a problem with the active choke

c. To simultaneously direct flow to the mud gas separator and the mud pits

d. To simultaneously direct flow to the vent line and the mud pits

9.5 What is the recommended diameter for the choke manifold bleed line (the line that by-passes the chokes) according to API Standard 53?

a. At least 5 inches.

b. At least equal to the diameter of the choke line

c. Less than 3 inches

d. The same diameter as the other lines on the choke manifold

9.6 What is the main function of the choke in the overall BOP system?

a. To direct hydrocarbon to the flare
b. To direct the wellbore fluids to the mud/gas separator
c. To shut the well softly
d. To hold back pressure while circulating out the kick.

9.7 What is the purpose of the choke manifold vent/bleed line that by-pass the choke?

a. To by-pass the chokes and bleed off high volumes of fluid
b. To by-pass the chokes and connect the choke manifold to the kill line.
c. To connect to the Mud Gas Separator (MGS).
d. To connect the bleed lines to the buffer tanks.

9.8 Why does the bleed line bypass the choke, have the same diameter of the choke line?

a. To continue circulating the well while maintaining minimum back pressure.
b. To prevent hydrate formation.
c. To increase bottom hole pressure.
d. To maintain the same mud weight in the well.

9.9 How Many remote/ adjustable chokes should a choke manifold of RWP of 10,000 have?

a. One
b. Two
c. Three

10 Stab-In Valves

10.1 When RIH with a solid float, the drill string must be filled from the top on a regular basis. What might be the result if this procedure is not carried out correctly ?*(Two answers)*

a. Drill pipe Collapse

b. Drop in BHP due to air bubble (when bubble is displaced inside the annulus)

c. Riser collapse

d. Mud losses

e. Stuck pipe.

10.2 A kick is shut-in with the bit 35 stands off-bottom. A Drill Pipe Safety Valve (DPSV) (full opening type) is installed on the drill pipe, and closed.

To strip back to bottom, what equipment is required to be made up onto the drill string?

a. An IBOP on top of the closed safety valve.

b. An IBOP with a DPSV installed on top in the closed position.

c. An open DPSV with a closed IBOP installed on top.

d. Only the DPSV in the closed position.

10.3 You are tripping out of the hole and are 5000 feet off-bottom, when the well starts to flow. Which type of Drill Pipe Safety Valve (DPSV) should you use to secure the well and to strip back to bottom?

a. Drop a dart valve into the string and pump to the dart sub to secure the well. Then add a non-return type inside BOP (IBOP) for stripping.

b. Install a float valve on the pipe to secure the well. Then install a non-return inside BOP (IBOP) above for stripping.

c. Install a full-opening type DPSV to secure the well. Then install a non-return type inside BOP (IBOP) above for stripping.

d. Install a non-return type IBOP to secure the well. Then add a full-opening type DPSV above for stripping.

10.4 During a trip out of the well, there is a kick while the bit is half way to surface. A Drill Pipe Safety Valve (DPSV) is installed on the drill string and then closed. There is no float in the drill string and the well is shut in on the Annular BOP.

What is the Driller's next action before stripping back to bottom?

a. Install a DPSV on top of the IBOP in the closed position.

b. Install the IBOP above the DPSV, and then open the DPSV

c. Keep the DPSV in the closed position.

d. Replace the DPSV with an IBOP

10.5 Inside blowout preventers (IBOPs) should be placed on the rig floor at all times, ready for use, to fit the tubulars use.

Which of the following are correct for this type of valve? *(Three answers)*

a. It can be run in the hole in the open position.

b. It cannot be pressure tested before use.

c. It has the potential to leak through the open/close key.

d. It has to be pumped open to read the Shut In Drill Pipe Pressure (SIDPP)

e. It is easier to stab than a Drill Pipe Safety Valve (DPSV) when flow is encountered up the drill string.

f. It is kept in its open position by a rod secured by a T-handle.

g. It will not allow wire line to be run inside the drill string.

10.6 In which of the following situations is it an advantage to use a float valve in the drill string?

a. To avoid flow back while tripping or during a connection.

b. To read the drill pipe pressure value following a well kick.

c. To allow reverse circulation.

d. To reduce surge pressure.

10.7 While pulling out a kick is taken. The Hydril "drop in back-pressure valve" is dropped and pumped down and the well shut in.

After a while it is observed that the pressure on the drill pipe gauge continues to increase. Which of the following are the causes of this pressure increase? *(Two answers)*

a. There is an obstruction in the annulus.

b. The special ring to stop the "drop in back pressure valve" has not been inserted.

c. The stabilizers are balled up.

d. The special "seat" has not been inserted in the drill string.

10.8 While pulling out of the well, there is a kick. The drop-in back pressure valve is dropped and pumped down, and the well is shut-in.

After a short duration, the pressure on the drill pipe gauge continues to increase.

What could cause this pressure increase? ***(Two answers)***

a. The drop in back pressure valve is not yet seated

b. The bit nozzles are plugged

c. The choke valve is still open

d. The indented surface inner seat is washed out by the mud flow

e. The stabilizers are balled up

10.9 A well kicks with the bit off bottom and is shut-in, and the Kelly cock should now be in place.

The decision is made to strip back into the hole.

What equipment should be made up onto the string in order to perform the stripping operation safely, assuming there is no float sub or dart sub in the string?

<u>Note:</u> Drilling pipe safety valve = Kelly Cock

Inside BOP = Non –return valve

a. Only the drill pipe safety valve in the open position.

b. Only the inside IBOP.

c. The drill pipe safety valve (open) with an inside BOP installed on top.

d. The inside BOP with a drill pipe safety valve (Closed) installed on top.

e. Only the drill pipe safety valve in the open position.

10.10 What is the main limitation of drill string flapper valves when stripping to bottom?

a. The flapper valve is a not tested barrier.

b. The shut in Drill Pipe Pressure (SIDPP) cannot be read on surface.

c. You must reverse circulate before stripping to bottom.

d. You must run wireline inside the drill string to open the flapper valve.

10.11 The driller has installed an Inside Blowout Preventer (IBOP) on to the drill string and has shut the well. Is circulation of kill mud possible?

a. Reverse circulation is possible.

b. Circulation down the drill string is possible

c. No circulation is possible until a double box sub is installed

d. No circulation is possible until the IBOP is opened by the operating crank

10.12 Which one of the following statements about an Inside Blowout Preventer is correct?

a. It allows reverse circulation when installed in the drill string

b. It can be opened or closed by turning a wrench connected to an operating crank

c. It is opened by drilling fluid pumped down the drill string

d. It requires a double box sub in order to be installed in the drill string

10.13 Before cutting the drilling line with the bit at the casing shoe, which item of equipment must be installed to make the operation safe?

a. A circulating head in the closed position

b. A Drill Pipe Safety Valve (DPSV) in the open position and an inside Blowout Preventer (IBOP) in the closed position.

c. A full opening Drill Pipe Safety Valve (DPSV) in the open position

d. An Inside Blowout Preventer (IBOP) in the closed position

10.14 With drill pipe in the hole, a float in the drill string and the well shut in under pressure with the annular preventer, which of the following circulation routes is possible?

a. Circulation down the choke line and up through the drill string

b. Circulation down the drill string and up through the choke line.

c. Circulation down the drill string and up through the kill line

d. Circulation down the kill line and up through the drill string

10.15 When should the top drive (or Kelly) mounted safety valve be closed?

a. In well control situations when the surface pressures may exceed the rated working pressure of surface equipment

b. When connections are made, to save the spilling of drilling fluid

c. When the rotary Kelly hose is being replaced

d. When the swivel packing is being replaced

11 <u>Connections</u>

11.1 Which statements are correct with respect to ring gaskets used for flange to flange make up? ***(Two answers)***

a. Type RX and BX ring gaskets provide a pressure energised seal.

b. The same material specifications apply for ring gaskets as for ring grooves.

c. Ring gaskets may be used several times.

d. Type 6BX flanges, which are designed for face-to-face make up, make use of type BX ring gaskets only.

11.2 Which statements about ring gaskets are correct? ***(Two answers)***

a. BX ring gaskets require to be lubricated before fitting

b. Only BX ring gaskets can be used 6BX type flanges

c. Ring gaskets are designed to be used several times

d. The same material specifications apply to ring gaskets as to ring grooves

e. Type BX ring gaskets provide a pressure-energised seal

11.3 What precautions should you take when fitting a BX ring gasket?

a. The gasket and ring groove should be coated in environmentally friendly oil and then fitted.

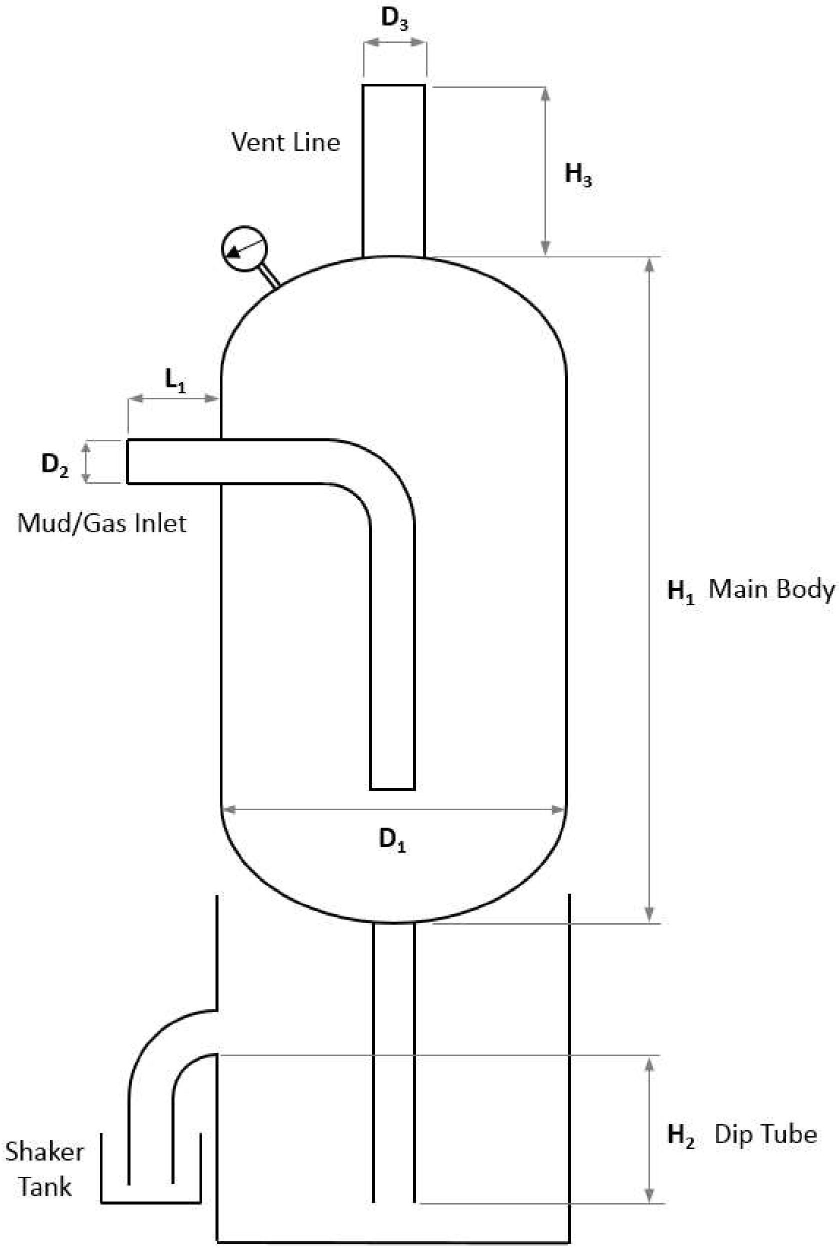
b. The gasket and ring groove should be coated in waterproof grease and then fitted.

c. The gasket and ring groove should be wiped clean and then fitted dry.

d. The gasket and ring groove should be wrapped in Teflon tape and then fitted.

12 <u>Mud Gas Separator</u>

12.1 Which of the following dimensions in the diagram below limit the maximum working pressure of mud gas separator (MGS)?



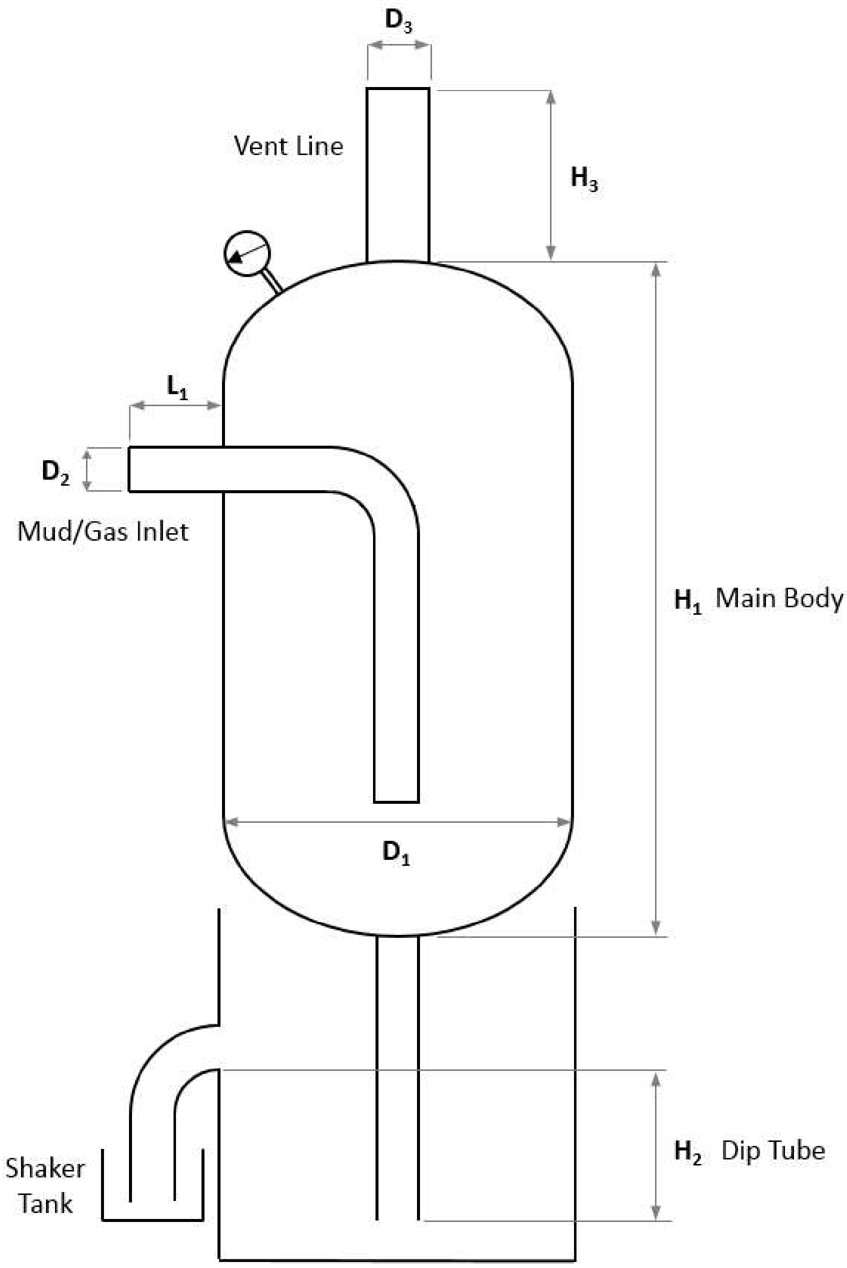
a. The height of the main body (H_1)

b. The height of the dip tube (H_2)

c. The total height of vent line (H_3)

d. Diameter of the inlet pipe (D_2)

12.2 In the figure below which dimension determines the back-pressure generated within the handling capacity of the mud gas separator?



a. The length and the inside diameter (D_2) of the inlet pipe from the buffer tank to the choke manifold.

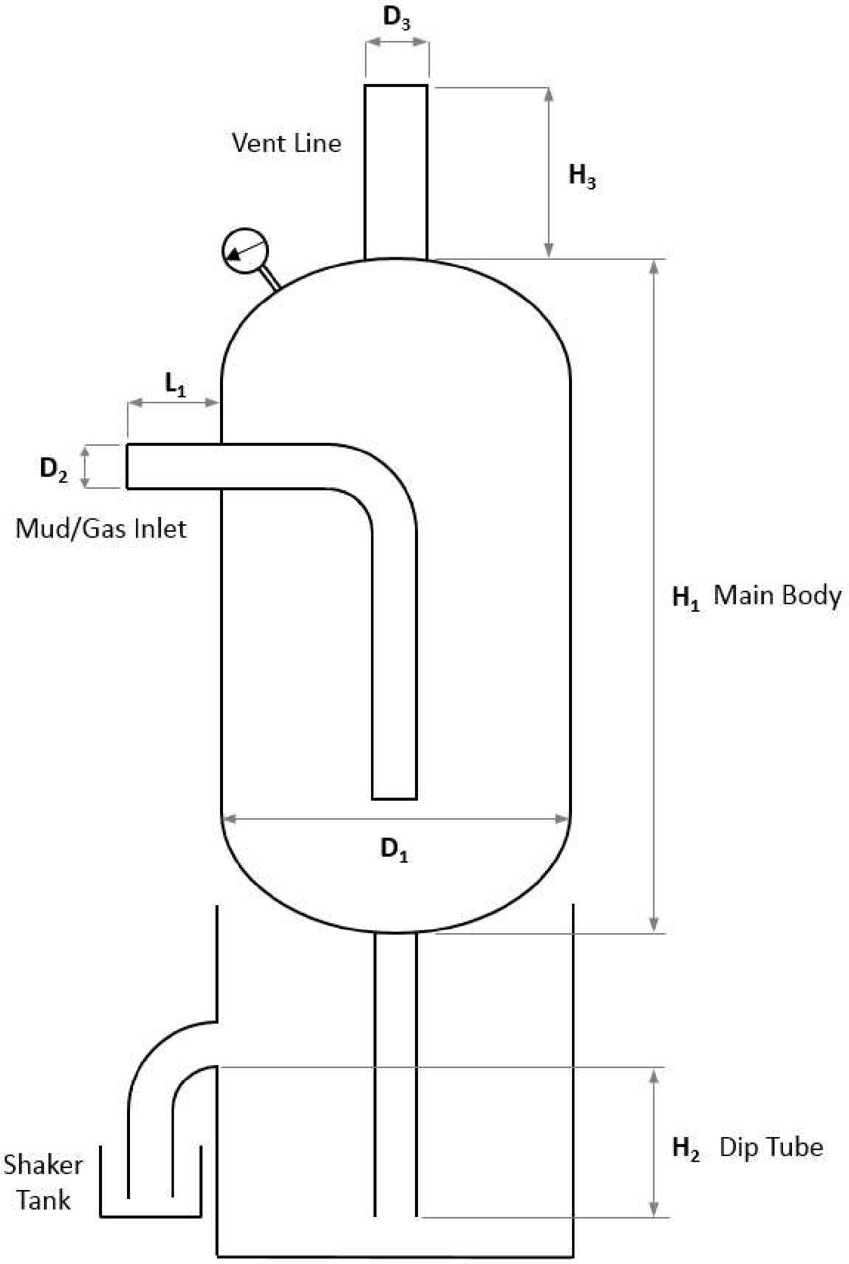
b. The dip tube height (H_2)

c. The body height (H_1) and the body inside diameter (D_1)

d. The derrick vent pipe height (H_3) and inside diameter (D_3)

12.3 Use the illustration of the mud gas separator in figure below and the following data to calculate the operating pressure at which gas blow through may occur:

H_1 – body height	**= 20 feet**	**H_2 – dip tube height**	**= 15 feet**
H_3 –vent line height	**= 147 feet**	**Mud density**	**= 10 ppg**



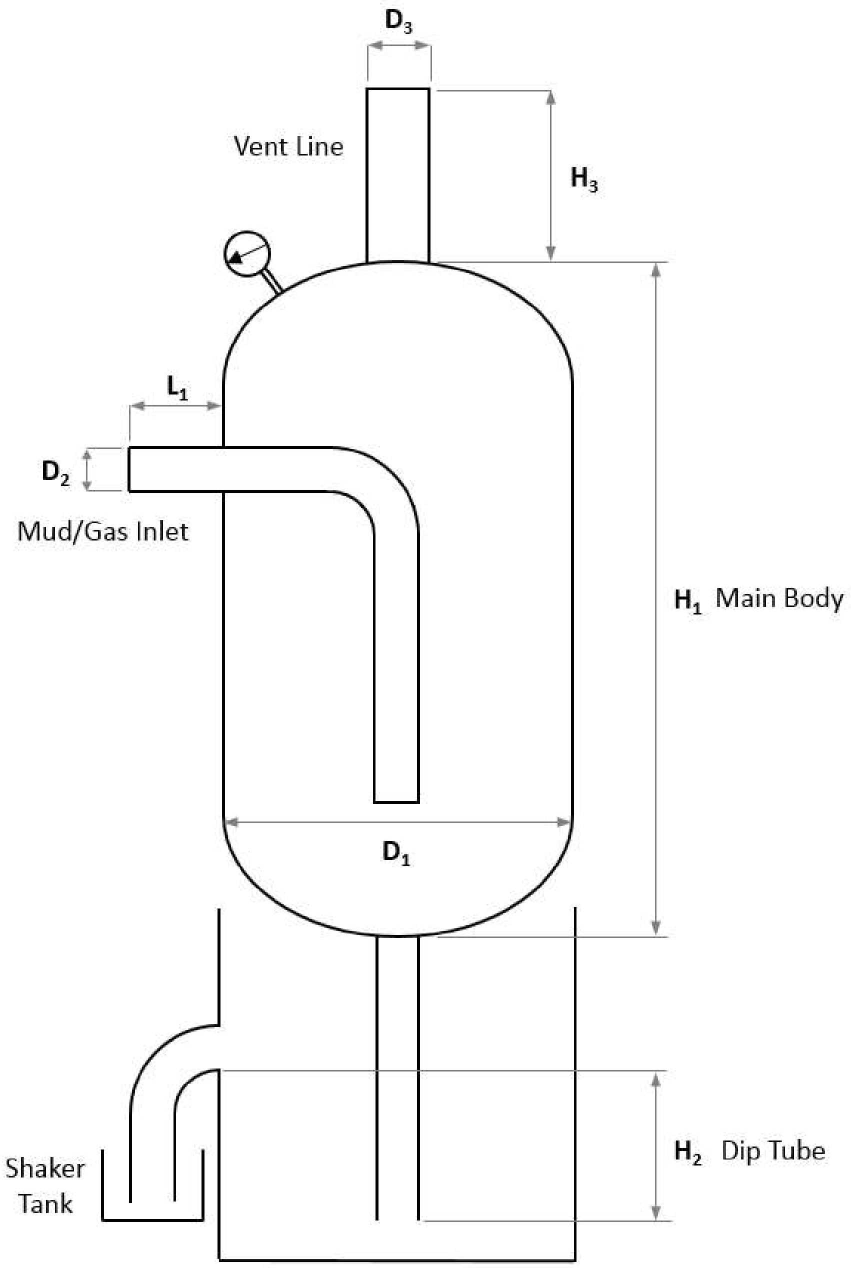
a. 3 – 4 psi

b. 5 psi

c. 7 – 8 psi

d. 76 – 77 psi

12.4 In the figure below, which of the following dimension is the primary factor in limiting the capacity of the mud-gas separator?



a. The height of the dip tube (H_2)

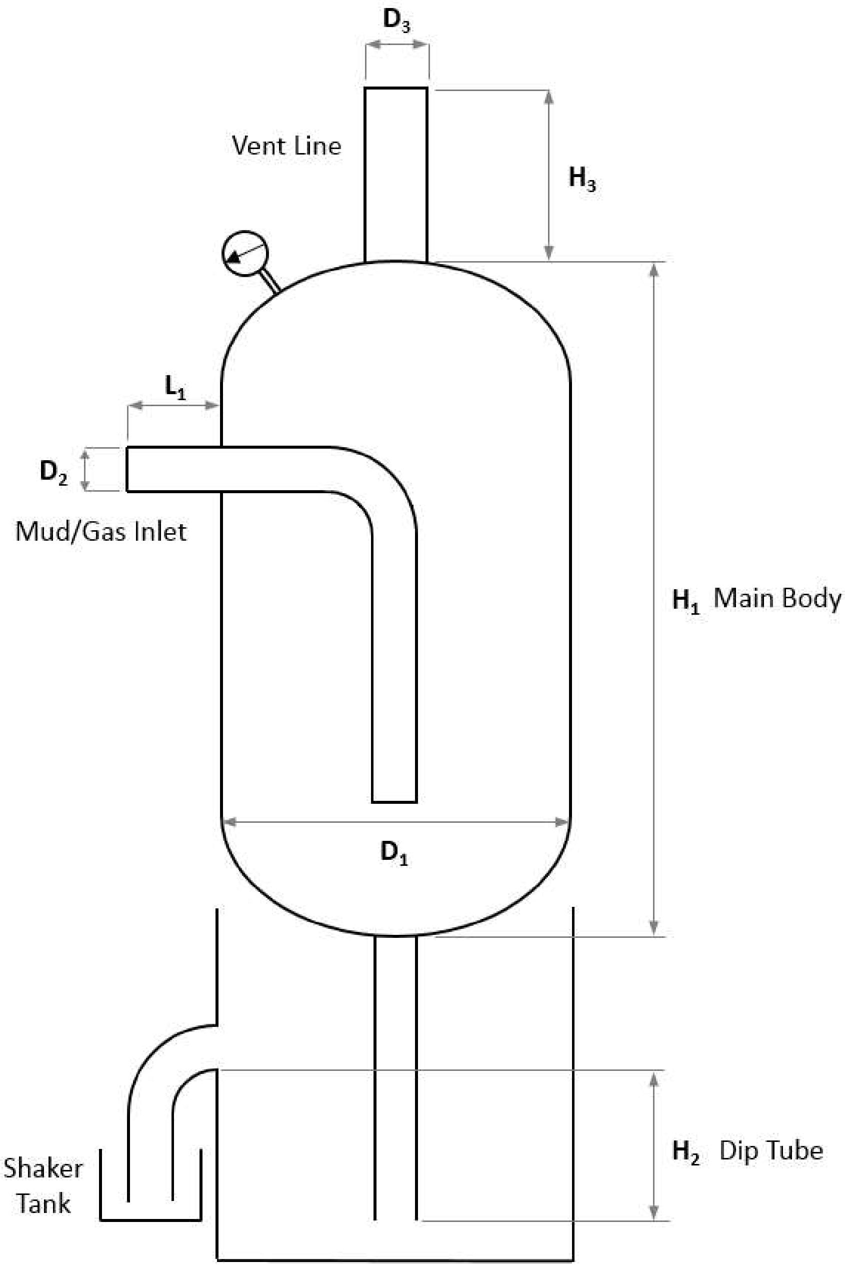
b. The height of the main body (H_1)

c. The total height of the vent line (H_3)

12.5 The mud gas separator illustrated in the following figure has the following dimensions:

H_1 – body height	**= 30 feet**	**H_2 – dip tube height**	**= 15 feet**
H_3 –vent line height	**= 150 feet**	**Mud density**	**= 11.5 ppg**

Assume the kick is condensate and the returning fluid has a gradient 0.3 psi/ft.



a. 9 psi

b. 4.5 psi

c. 45 psi

12.6 The Mud Gas Separator shown in Figure has the following dimensions:

H1 - Body Height:	**26 feet**
H2 – Dip Tube Height:	**15 feet**
H4 – Derrick vent line height:	**130 feet**
Mud density:	**12.5 ppg**

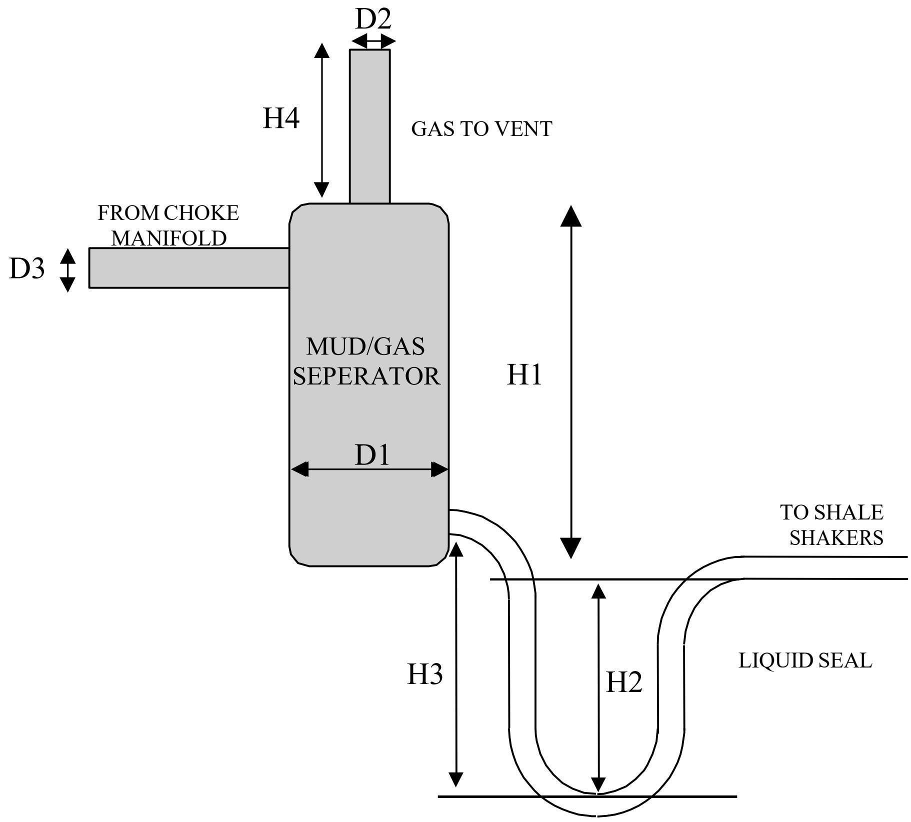
Calculate the maximum operating pressure of this MGS when gas cut mud with a density of 10 ppg is circulated?

a. 13.5 psi

b. 67.6 psi

c. 7.8 psi

d. 9.75 psi



Mud weight: 10 ppg.

12.7 The maximum operating pressure allowed in a mud/gas separator is often calculated on the assumption that there is mud in the liquid seal.

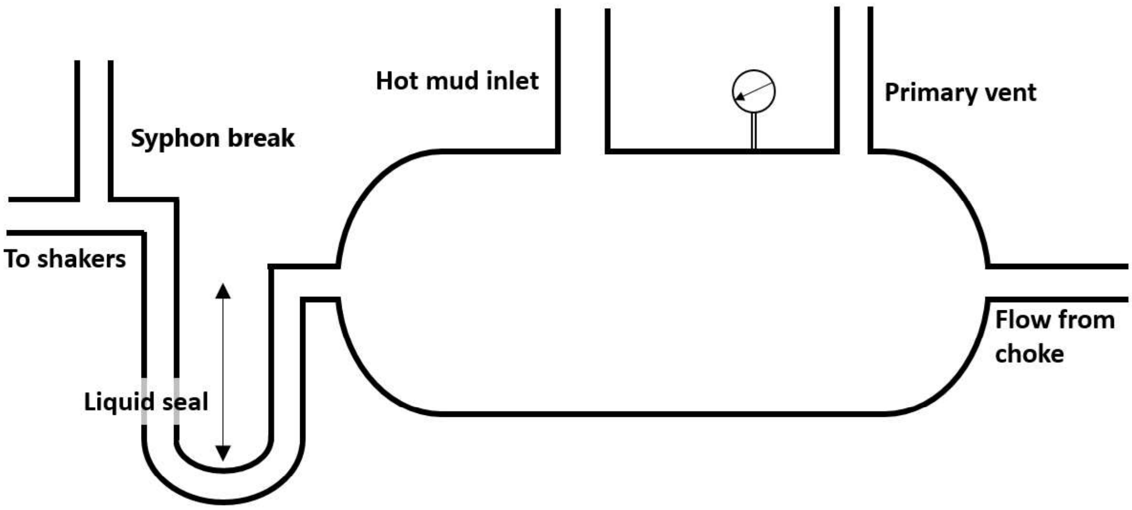
What would be the effect on this maximum operating pressure as a condensate (or oil) kick is circulated through the mud/gas separator?

a. Maximum operating pressure would decrease

b. Maximum operating pressure would increase

c. No effect

12.8 **When a mud gas separator is working with its handling capacity, which parameters create the back pressure on pressure gauge?** ***(Two answers)***



a. The flow rate into the MGS

b. The flow rate of hot mud into the MGS

c. The height and diameter of secondary vent

d. The height of the liquid seal

e. The length and diameter of the vent line

12.9 What is the primary reason for choosing to circulate out a kick at a slow rate?

a. To allow the gas to expand

b. To avoid exceeding the surface equipment handling limitations including the Mud Gas Separator

c. To prevent choke washout

d. To prevent formation washout at bit depth

12.10 Why is pressure build up in the Mud Gas Separator (MGS) dangerous while circulating out a kick?

a. Pressure build up may allow gas to be blown up at the derrick vent line.

b. Pressure build up may allow gas to enter the shale shaker area.

c. Pressure build up will increase the risk of lost circulation

d. Pressure build up will make choke adjustment difficult

12.11 When circulating out a gas kick at 30 SPM, the pressure inside the Mud Gas Separator (MGS) increases close to the maximum allowable pressure.

What should you do to reduce the risk of liquid seal loss in the MGS U-tube?

a. Increase the SPM to circulate the gas through the MGS faster

b. Shut in the well and bullhead the gas kick back to the casing shoe

c. Shut in the well and then re-establish circulation at a lower SPM.

d. Shut in the well and bleed the gas to reduce the casing pressure.

12.12 When circulating clean mud into the Mud Gas Separator (MGS) through the "hot loop" during a well control event, where must the mud be taken from to maintain the ability to monitor the pit level?

a. The active system

b. The drilling fluid reserve system

c. The pre-mix tank

d. The trip tank

12.13 Some mud gas separators are fitted with "hot loop" to circulate clean mud into the MGS when kick is being circulated out.

What is the main reason for this function?

a. To maintain the liquid seal full of clean (uncontaminated) mud as far as possible whilst a kick is circulated out.

b. To increase the separation efficiency of the mud gas separator.

c. To fill the vessel with light fluid to increase its efficiency.

d. To displace the liquid seal to clean mud every 12 hours.

12.14 A mud gas separator should be fitted with a pressure sensor or gauge to monitor the pressure inside the vessel.

Why is this?

a. To determine the amount of gas being vented.

b. To know when the vent line is plugging

c. To avoid the loss of liquid seal thus allowing gas to enter the shale shaker area.

13 <u>Vacuum Degasser</u>

13.1 A Vacuum Degasser is often used to remove gas from drilling fluid while drilling.

Where the suction line to the Vacuum Degasser should be connected according to best practice?

a. Upstream of the mud/gas separator.

b. From the mud/gas separator vent line.

c. Inside the mud/gas separator.

d. Downstream of the mud gas separator.

13.2 How does a vacuum degasser work?

a. Gas cut mud enters the degasser and forms a thin layer over the internal baffle plates it is vented to the overboard line

b. Gas cut mud enters the degasser and forms a thin layer over the internal baffle plates the vacuum inside the vessels helps removal of gas

c. Gas cut mud enters the degasser and forms a thick layer over the external baffle plates excess pressure inside the vessel forces the gas to escape

d. Gas cut mud enters the degasser and forms a thin layer over the internal baffle plates atmospheric pressure in the vessel helps to remove the gas

13.3 Can a vacuum degasser be used instead of a mud gas separator during well control operations?

a. No, because its position and function makes it unsuitable to handle large volumes of gas

b. No, because the mud/gas separator is used to determine gas density

c. Yes, because the flow rate used during a well kill is small

d. Yes, because they perform the same function

13.4 What does a vacuum degasser do?

a. It is used to remove excess barite from the drilling fluid downstream on the shale shakers

b. It removes drill solids from the drilling fluid upstream of the shale shakers

c. It removes large volumes of gas from the drilling fluid upstream of the shale shakers

d. It removes gas from the drilling fluid downstream of the shale shakers

Equipment Model Answers

1.1	d	2.13	a, b, c	4.1	b	5.11	a
1.2	d	2.14	a	4.2	a, c	5.12	a
1.3	b	2.15	d	4.3	a	5.13	a, c
1.4	c	2.16	c	4.4	b	5.14	c
1.5	a, d	2.17	c	4.5	c	5.15	a
1.6	b	2.18	b	4.6	d	5.16	b
1.7	a	2.19	c	4.7	b	5.17	c
1.8	d	2.20	b	4.8	c	5.18	b
1.9	b	2.21	b	4.9	d	6.1	b
1.10	d	2.22	d	4.10	d	6.2	i-a, ii-a
1.11	a, e	3.1	a	4.11	a	6.3	c
1.12	a, b, c	3.2	a, b	4.12	b	6.4	b
1.13	d	3.3	b	4.13	c	6.5	b
1.14	c	3.4	c	4.14	a	6.6	b
1.15	c	3.5	d	4.15	b, d, e	6.7	a
2.1	d	3.6	a	4.16	b	6.8	a
2.2	b, d	3.7	d	4.17	c	6.9	d
2.3	i-a, ii-a	3.8	b	5.1	a	6.10	d
2.4	3-7-8-9-25	3.9	c	5.2	a	6.11	d
2.5	c	3.10	c	5.3	d, e	6.12	c
2.6	c	3.11	a	5.4	b	6.13	c
2.7	d	3.12	c	5.5	b	6.14	b
2.8	c	3.13	a, b, d	5.6	d	6.15	b
2.9	d	3.14	a, b, c	5.7	b	6.16	d
2.10	a	3.15	a	5.8	a, b	6.17	c
2.11	a	3.16	c	5.9	a	6.18	b
2.12	c	3.17	b	5.10	a	6.19	e
		3.18	a				

6.20 a
6.21 a, e
6.22 c
6.23 a
6.24 b
6.25 c
6.26 c
6.27 c
6.28 a, c
6.29 a, e
6.30 b
6.31 c
6.32 d
6.33 a
6.34 b
6.35 b
6.36 d

7.1 a, b
7.2 b, d
7.3 d

8.1 d
8.2 a
8.3 a
8.4 b

9.1 b
9.2 a
9.3 a
9.4 b
9.5 b
9.6 d
9.7 a
9.8 a
9.9 b

10.1 a, b
10.2 c
10.3 c
10.4 b
10.5 d, f, g
10.6 a
10.7 b, d
10.8 a, d
10.9 c
10.10 a
10.11 b
10.12 c
10.13 c
10.14 b
10.15 a

11.1 a, d
11.2 b, e
11.3 c

12.1 b
12.2 d
12.3 c
12.4 a
12.5 b
12.6 c
12.7 a
12.8 a, e
12.9 b
12.10 b
12.11 c
12.12 a
12.13 a
12.14 c

13.1 d
13.2 b
13.3 a
13.4 d

Part 2: P & P

Version **Nov-2019**

Theoretical Well Control Questions

1 Risk Management

1.1 Kicks that lead to blowouts are such an uncommon occurrence that there is no need to make provision for them when planning a well

a. True

b. False

1.2 What is one essential requirement of a Management of Change (MOC) procedure?

a. A change to procedure can be authorized using a previous risk assessment.

b. All team members must be aware of the agreed change before starting the operation

c. Changes to drilling procedures only require authorization and documentation by the Assistant Driller

d. Only the accountable manager can do a MOC risk assessment

1.3 What is one essential requirement of Management of change (MOC) procedure

a. Changes to drilling procedure only require authorization from the assistant driller.

b. Only the accountable manager can do a MOC risk assessment.

c. All changes of procedure require a new risk assessment to be done.

d. Only team leaders must be aware of the agreed change before starting the operation.

2 Barriers

2.1 What is the main purpose of BOP equipment?

a. To provide a hydraulic barrier against unplanned flow between the drill string and casing
b. To provide a mechanical barrier against unplanned flow to surface during well operations
c. To provide a mechanical barrier to prevent dropped objects falling into the well
d. To provide a mechanical seal to pressure test the casing and wellhead.

2.2 What type of well barrier elements are required to form a barrier envelope?

a. A combination of well barrier elements that prevent flow to the environment or to an open formation.
b. A combination of well barrier elements to prevent flow into open formation.
c. Several BOP rams to prevent flow to the environment.
d. The wellhead, casing and cement in a well

2.3 What is the meaning of well-barrier envelope?

a. All Mechanical barrier.
b. Use the mud with surface pressure to prevent intrusion of formation fluid to the well.
c. It is a combination of barriers that prevent the intrusion of formation fluids to the well, to another formation or to the atmosphere
d. The use of over balance to prevent intrusion of formation fluid to the well.

2.4 Which correct action should be taken if a well barrier fails while testing, as per API Standard RP 53?

a. Tightening, Repair or any other work must be done under pressure then retest it again.
b. It is not important neither to pressure test this barrier after fixing the problem nor the corrective action.
c. Bleed off pressure to half pressure, repair and pressure test it.
d. Tightening, Repair or any other work must done only after verification that all pressure is released and all parties are agreed that no chance of trapped pressure.

2.5 What should you do if an annular BOP fails its pressure test?

a. No action is required if the rams are successfully tested.

b. You do not need to retest it until the next planned test date

c. You should remove the annular from service

d. You should repair it immediately and then re-test it

2.6 Who is authorized to sign the test chart?

a. Mechanic

b. Pump operator, drilling contractor representative and operator reparative.

c. BOP engineer

d. Electrician

e. Driller or Senior Tool Pusher

2.7 Which of the following is necessary to maintain primary well control during tripping?

a. The hydrostatic pressure exerted by the drilling mud column must remain higher than the formation pressure

b. Mud pumps must be in good working order

c. A minimum of one inside blowout preventer (IBOP) must be available on the drill floor

d. The level in the active tank must be constant

2.8 What is the main reason for doing a check trip and then circulating bottoms-up?

a. So that pipe can be pulled to surface at a faster rate

b. To cool the bit

c. To test that the drill crew is ready for tripping

d. To verify that primary well control has been maintained when pulling pipe out of the hole.

2.9 What is the correct definition of "primary well control" during normal drilling operation?

a. Preventing a kick by maintaining drilling mud hydrostatic pressure equal to or greater than formation pressure.

b. Preventing the flow of formation fluid into the well bore by maintaining the sum of drilling mud hydrostatic pressure and dynamic pressure loss in the annulus equal to or greater than formation pressure.

c. Preventing the flow of formation fluid into the well bore by keeping the dynamic pressure loss in the annulus equal to or greater than formation pressure.

d. Preventing the flow of formation fluid into the well bore by using BOP equipment when the hydrostatic pressure in the well bore does not balance or exceed the formation pressure.

2.10 Which statement describe the secondary well barrier?

a. A secondary well barrier is the secondary object that prevents flow from a source

b. A secondary well barrier will not prevent flow from a source

c. A secondary well barrier controls the closure of blow out preventer

d. A secondary well barrier is the first object that prevents flow to well bore.

2.11 Pressure has built up between two casing strings in a well, a poor cement job has been performed on the inner casing string, what could the consequences of this pressure build-up be? *(Three answers)*

a. The inner casing could collapse

b. The ECD will increase

c. These could be different sticking

d. The formation below the outer casing shoe could fracture

e. The outer casing could burst

2.12 A cement bond log (CBL) showed that there is a bad cement job between two casing strings. What is the immediate effect of a bad cement job? *(Three answers)*

a. The inner casing could collapse

b. The ECD will increase

c. These could be different sticking

d. The formation below the outer casing shoe could fracture

e. The outer casing could burst

2.13 Pressure has built up between two casing strings in a well, a poor cement job has been performed on the inner casing string, what could the consequences of this pressure build-up be?

a. The inner casing could collapse
b. The ECD will increase
c. These could be different sticking
d. The outer casing could burst

2.14 Pressure has built up between two casing strings in a well, a poor cement job has been performed on the inner casing string, what could the first consequence of this pressure build- up that will affect the well integrity?

a. The inner casing could collapse
b. The ECD will increase
c. These could be differential sticking
d. Fracture in formation
e. The outer casing could burst

3 Pressure in Earth's Crust

3.1 What is the most common cause of abnormally high formation pressures worldwide?

a. Carbonate layers.
b. Depleted sands.
c. Naturally fractured lime stone.
d. Under-compacted shale

3.2 A formation is over-pressured by an artesian effect. What has created the over-pressure?

a. A formation water source is at a higher level than the rig floor
b. The density difference between gas and formation fluid
c. The formation is compacted from the overburden
d. The rig floor is higher than the formation water source

3.3 Which one of the following values is generally accepted as a normal formation pore pressure gradient?

a. 0.508 psi/ft.
b. 0.442 psi/ft.
c. 0.42 psi/ft.
d. 0.465 psi/ft.

3.4 What is meant by abnormal pressure?

a. The excess pressure due to circulating mud at high rates.
b. The excess pressure that needs to be applied to cause 'leak-off.
c. Heavy weight mud used to give an overbalance.
d. The formation fluid pressure that exceeds formation water hydrostatic pressure

3.5 In what situations would formation pressures be called "abnormal pressure" (over-pressure)?

a. When excess pressure must be applied to cause leak-off into a normally pressure formation
b. When heavy density fluid is used to create large overbalance
c. When the formation fluid pressure exceeds formation water hydrostatic pressure
d. When there is excess pressure due to circulating fluid at high rates

3.6 When would you consider formation pore pressure to be abnormal?

a. When a rock formation contains fluids.

b. When drilling with an oil based drilling fluid

c. When the gradient of the formation pressure is above 0.465 psi/ft

d. When the gradient of the formation pressure is below 0.433 psi/ft

4 Static and Dynamic Pressures

4.1 Which one of the following will affect Bottom-hole pressure (BHP) while circulating at a constant flow rate? *(Two answers)*

a. Mud density

b. Annulus pressure loss

c. Pump pressure

d. Pressure loss through the bit nozzles

4.2 The equivalent circulating density (ECD) determines the actual bottom hole pressure while circulating.

Which part of the system pressure losses contributes to the ECD?

a. The pressure loss in the surface system

b. The pressure loss over the nozzles

c. The pressure loss in the drill string

d. The pressure loss in the annulus

e. The pressure loss in the open hole section only

4.3 The Driller pumps a heavy slug and displaces it to the drill pipe with active pit fluid.

What effect will this have on the fluid pits after disconnecting the top drive?

a. Decrease in volume

b. Increase in volume

c. No change in volume

4.4 During normal drilling operations, 20 bbl of light fluid is pumped into the string followed by original mud. With the light fluid inside the drill pipe, the Driller shuts down the pumps to monitor the well.

What happens to the Bottom Hole Pressure (BHP)?

a. The BHP pressure will increase, and the back pressure will show on the drill pipe pressure gauge.

b. The BHP pressure will remain the same, but a back pressure will show on the drill pipe pressure gauge

c. The BHP will decrease, and there will be no back pressure showing on the drill pipe pressure gauge.

4.5 Which factors will affect Bottom Hole Pressure (BHP) while circulating at a constant flow rate? ***(Two answers)***

a. Annulus pressure losses.

b. Drill string pressure loss.

c. Drilling fluid density.

d. Pressure losses through the bit nozzles.

e. Pump pressure.

4.6 The pit level increases when the pumps are off, but the pit level stays constant when the pumps are running. What could be the problem?

a. The hydrostatic pressure is greater than the formation pressure.

b. Annular pressure losses are creating an overbalance that prevents the well from flowing.

c. The pump pressure is greater than the hydrostatic pressure.

d. The pumps have failed.

4.7 If light pill is pumped in the drill string and followed by 10 bbls original mud. What can it lead to after disconnect the Top Drive/Kelly if the light pill doesn't come out from the nozzles? (NO FLOAT VALVE IN THE STRING)

a. Reduction in the bottom hole pressure.

b. Increase in the overbalance.

c. Nothing will happen.

d. Back flow from the drill string.

4.8 A heavy mud pill is circulated around a well. When will the Bottom Hole Pressure (BHP) first increase? Ignore dynamic pressure losses in the well.

a. As soon as pumping the pill in to the drill string starts

b. Once the entire pill is in the annulus.

c. Once the entire pill is pumped into the drill string and is about to exit the bit.

d. Once the pill starts to be displaced into the annulus.

4.9 What is the reason for having a trip margin?

a. To allow for a level drop in the well if there are losses.

b. To compensate for possible swabbing effects during pulling out of the hole.

c. To create a safety margin in case the trip tank readings are inaccurate.

d. To create an overbalance when back on bottom drilling.

4.10 What well control problem can excessive over-pull cause when tripping out of hole?

a. A broken drill string

b. Stuck pipe in the well

c. Surging

d. Swabbing

4.11 Gas cut drilling fluid is circulated, when is the BHP at its lowest?

a. When the gas is about halfway up the well bore.

b. When the gas is at or near the bottom of the well bore

c. When the gas is near the surface

d. When the gas reaches the casing shoe

5 Top-hole

5.1 Formation strengths are generally weak when drilling top-hole and total losses may occur. How can the risk of total losses be reduced when drilling top-hole? (Two Answers)

a. By pumping slowly to reduce the drill string pressure loss.
b. Keeping a high overbalance.
c. By controlling penetration rate to prevent loading the annulus with cuttings.
d. Reduce the Mud weight as possible to reduce the risk of formation fracture

5.2 What is one good operating practice to help to minimize well control problems while drilling top-hole section?

a. Maintain a high drilling rate
b. Maintain a high over-balance in the drilling fluid to avoid going under-balance
c. Maintain the drilling fluid density as low as possible to prevent formation fracture
d. Maintain very high tripping speeds when running in or out of the hole

5.3 Which of the following statements are good operating practices when drilling top-hole formations where there is a risk of shallow gas? *(Two answers)*

a. Maintain high rate of penetration and keep mud viscosity as high as possible.
b. Use a heavy weight mud to create maximum overbalance.
c. Pump out of the hole on trips.
d. Use oil-based mud.
e. Drill a pilot hole at a controlled rate.

5.4 During top-hole drilling from a jack-up rsig, the well starts to flow due to shallow gas.

What will be the safest action to take to secure the safety of the rig and personnel?

(Two answers)

a. Start pumping mud into the well at the highest possible rate.
b. Activate the diverter system and remove non-essential personnel from the rig floor.
c. Shut in the well and prepare for kill operation.
d. Activate the blind/share ram to shut in the well.
e. First, line up to the mud/gas separator, close the diverter and send personnel from the rig floor.

5.5 When drilling top-hole with a risk of shallow gas, which actions are considered good practice? *(Two answers)*

a. Drill a pilot hole at a slow controlled rate.

b. Maintain high Rate of Penetration (ROP) so that fluid viscosity is as high as possible.

c. Pump out of the hole while tripping

d. Regularly pump a fresh water pill to clean cuttings from the hole.

e. Use heavy density fluid to create maximum overbalance

5.6 When top-hole drilling, a well starts to flow due to shallow gas. What is the safest action to take to secure the safety of rig and personnel?

a. Activate the blind/shear rams to shut in the well

b. Activate the diverter system, and remove non-essential personnel form the rig floor and hazardous areas.

c. Line up the Mud Gas Separator, (MGS), activate the diverter system and remove personnel from the rig floor

d. Shut in the well and prepare for kill operations immediately

5.7 If a shallow gas flow is detected, which action is required as the flow is diverted?

a. Decrease the pump rate

b. Increase the pump rate

c. Maintain the pump rate

d. Stop pumping

5.8 Is it true that shallow gas kicks are easier to handle than those taken when drilling deeper?

a. Yes.

b. No.

6 L.O.T. and M.A.A.S.P.

6.1 When drilling into new formation, the formation pressure increases. To maintain a reasonable overbalance on bottom, the drilling fluid density is increased. How will this affect the MAASP?

a. The MAASP will decrease.
b. The MAASP will increase.
c. The MAASP will stay the same.

6.2 When should MAASP be recalculated?

a. After changing the mud density
b. After each bit change
c. At the beginning of each shift
d. Immediately before entering a pay zone.

6.3 Which critical pressure is calculated using the results of the Leak-Off Test (LOT)?

a. Dynamic Casing Pressure
b. Final Circulating Pressure (FCP)
c. Initial Circulating Pressure (ICP)
d. Maximum Allowable Surface Pressure (MAASP)

6.4 Which parameter would affect the Leak-off Test (LOT) pressure?

a. The fluid pump circulating rate for the next drilling operation
b. The hydrostatic pressure at the casing shoe
c. The pressure limit for the fluid pump
d. The volume of the fluid in the annulus from the casing shoe to surface

6.5 Which of the following need to be known for a leak-off test to be correct? *(Two answers)*

a. The mud density in the well.
b. The volume of mud in the annulus from casing shoe to surface.
c. Slow circulating rate.
d. The pressure limit for the mud pump.
e. Mud hydrostatic pressure in the casing annulus.(TVD)

6.6 After setting casing, which actions should you take before doing a Leak-off test (LOT)? *(Two answers)*

a. Circulate the drilling fluid to equalize fluid densities in the hole
b. Drill out the casing shoe and into the new formation
c. Keep the bit close to bottom.
d. Line up for using the mud pump to do the leak-off test at the slow circulating rate
e. Mix and pump a high viscosity sweep

6.7 What is one condition that must be achieved to complete a successful Leak-Off (L.O.T.)?

a. The casing pressure test value will equal to the LOT value
b. The hole must be drilled to Total Depth (TD)
c. The Initial Circulating Pressure (ICP) must be used
d. The drilling fluid must be conditioned

6.8 Which information do you need for an accurate Leak Off Test (LOT). *(Two answers)*

a. The fluid density in the well.
b. The fluid pump circulating rate for the next drilling operation.
c. The pressure limit for the fluid pump
d. The True Vertical Depth (TVD) of the casing shoe.
e. The volume of fluid in the annulus form casing shoe to surface

6.9 Which factors can affect the Maximum Allowable Annular Surface Pressure (MAASP)?

a. The depth of the last casing shoe, the fracture pressure of the formation at the casing shoe and the drilling fluid density
b. The diameter of the last casing string, the fracture of the formations behind the casing shoe, and the kill fluid density
c. The maximum allowable pump pressure, the low gravity solids content of the drilling fluid, and the mud pump efficiency
d. The water loss of the drilling fluid, the formation pore pressure at the casing shoe, and the solids content of the drilling fluid.

6.10 In which situation would you expect fracture pressure to change?

a. After a formation change in the open hole section

b. Every time the drilling fluid density is changed

c. When the Shut In Casing Pressure (SICP) is higher than MAASP

d. When the BHA or bit is changed out

6.11 When performing a Leak-Off Test (LOT), which parameter must be accurately measured and recorded?

a. Fluid volume in open hole, density of the fluid used, and the True Vertical Depth.

b. Fluid volume in the casing, and Measured Depth (MD).

c. Pumping time until the leak-off, and the Measured Depth (MD).

d. Fluid volume pumped, density of the fluid used, and True Vertical Depth.

7 Kick Warning Signs

7.1 While drilling a head through a faulted formation, the flow meter drops from 50% to 42%. What is the most likely cause of this?

a. A swabbed kick on last connection.
b. A washout in the string.
c. Partial lost circulation
d. Total lost circulation.

7.2 After two hours of constant flow rate returns to the shaker house, the drilling fluid returns rate decreases significantly. What could be the reason for this decrease?

a. The Derrickman may be transferring drilling fluid out of the active pit.
b. The Driller may have increased the pump speed
c. There may have been an influx
d. There may be fluid losses to the well bore.

7.3 Which are warning signs of abnormal pressure at when there is constant rotary RPM, constant weight on bit (WOB) and constant pump rate? *(Three answers)*

a. A change in the shape of the cuttings at the shakers
b. A decrease in flow line temperatures
c. A drop in active tank level
d. An increase in pump pressure
e. An increase in trip tank level
f. Increased connection gas in returns
g. Varying penetration rate

7.4 Which are indicators that a well may be going under-balanced? *(Two answers)*

a. A change in the shape and size of the cuttings
b. A decrease in background gas levels
c. A significant increase in the pump pressure
d. A slight increase in the flow line fluid density
e. An increase in background gas levels

7.5 What should the driller do when connection gas is detected? *(Two answers)*

a. Control the drilling rate so that only one slug of connection gas is in the hole at any time
b. Increase the yield point in the active system
c. Minimize the time during a connection when the pumps are switched off
d. Pull out the hole to change the bit
e. Pump a low viscosity pill to reduce balling of bit and stabilizers

7.6 After a connection, the gas alarm sounds after bottoms-up strokes.

Which type of gas is this?

a. Background gas
b. Connection gas
c. Drilled gas
d. Recirculated gas

7.7 During the trip out of the well, and with the bit 1200 ft from bottom, the hole failed to take the calculated volume of drilling fluid from the trip tank, there is no flow from the well.

What is the next step that should be taken?

a. Pump remaining stands out of the hole.
b. Flow check, if negative continue to pull out of the hole.
c. Shut the well in and circulate hole clean.
d. Flow check, if negative run back to bottom and monitor returns.

7.8 After pulling ten stands out of the hole, the fluid it takes to fill the hole from the tank is less than calculated on the trip sheet.

What action is required?

a. Flow check. If there is no flow, continue to pull out of the hole to surface
b. Flow check. If there is no flow, displace a heavy slug into the annulus and continue to pull out of hole
c. Flow check. If there is no flow, run back to bottom while monitoring returns
d. Pump the remaining stands out of the hole

7.9 After pulling 1500 feet out of the hole, the Driller notices the well takes less fluid to fill than expected. What should the Driller do?

a. Flow check for at least 15 minutes. If the well is static, continue to pull out of the hole slowly to prevent any more swabbing

b. Flow check for at least 15 minutes. If the well is static, continue to pull out of the hole slowly, and do a flow check after every 5 additional stands pulled.

c. Flow check the well. If the well is static, circulate bottoms up and monitor returns for any swabbed reservoir gas or fluids. If the flow check is negative, continue to pull out of the hole slowly to prevent any more swabbing

d. Flow check. If the well is static, run back to bottom, and monitor the trip tank for additional gains. Circulate bottoms up and monitor the returns for any swabbed reservoir gas or fluids.

7.10 During a trip, the Driller suspects there is swabbed gas in the well. After a negative flow (the well is not flowing). What action is required?

a. Increase the speed of pulling each stand

b. Increase the fluid density or trip margin

c. Run back to bottom and circulate the hole clean

d. Shut the well in

7.11 When tripping out of the hole using a trip tank, which factors could indicate a possible influx to the Driller? *(Two answers)*

a. The hook load decreases as each stand is pulled

b. The trip tank level falls less than expected for each pulled stand

c. The trip tank level falls more than expected for each pulled stand

d. When pulling pipe, the flow meter in the flowline shows a decrease in the flow

e. With no pipe movement, the trip tank level increases

7.12 During a trip 15 stand of dry pipe have been pulled out, the volume of drilling fluid use to fill the hole was 8.2 bbl.

Well data:

Well depth:	**5800 ft**
Stand Length:	**90 ft**
Drill pipe Capacity:	**0.01782 bbl/ft**
Drill pipe metal displacement:	**0.0082 bbl/ft**
Drilling mud density:	**11.2 ppg**

Select the correct action from the following list:

a. The volume is not corrected due to swabbing but as long as the well is stable continue to pull out.
b. Continue to pull out since the situation seems to be under control.
c. Start pumping high density drilling mud in to the annulus.
d. An influx has been swabbed in, check for flow, if no flow, trip back to bottom while monitoring displaced volume and carefully then circulate bottom up.

7.13 After pulling 10 stands of pipe, a well takes less fluid than expected.

The driller completes a flow check and confirms the well is not flowing. What should the driller do next?

a. Because the well is not flowing, continue pulling pipe from the hole.
b. Establish if there has been an influx by running back to bottom and circulate bottom up
c. Pull another 10 stands and flow check.
d. Shut-in the well immediately and check for pressures.

7.14 While tripping out of the hole, the well starts flowing.

What is the first action to take?

a. Close the annulus and then make up the top drive
b. Pull back to shoe
c. Run back to bottom as quickly as possible
d. Stab in a Drill Pipe Safety Valve (DPSV) in the drill string and shut the well in.

7.15 How can the Driller prevent swabbing? (Two answers)

a. Increase the viscosity of the drilling fluid
b. Pull the drill pipe fast
c. Pull the drill pipe slowly
d. Pump a slug
e. Pump out of the hole

7.16 When pulling out of the hole, how do swab pressures affect the Bottom Hole Pressure (BHP)?

a. BHP will remain the same
b. BHP pressure will temporarily decrease
c. BHP will temporarily increase

7.17 If you trip into the hole too quickly, there is a risk of surging. What does that mean?

a. As drilling fluid is displaced from the hole into the trip tank, there is a decrease in hydrostatic pressure. This could cause a kick
b. As pipe is run in the hole, the bit and Bottom Hole Assembly (BHA) pulls formations gas into the well bore.
c. Pipe is run into the hole too quickly for the trip tank pump to maintain the correct level of drilling fluid in the well. This causes losses from the trip tank.
d. Pipe is run into the hole too quickly, increasing the Annular Pressure Losses (APL) caused by drilling passing the bit and Bottom Hole Assembly.

7.18 After a round trip, the driller circulates bottom up. The mud logger noticed gases in the shale shaker area.

What is the cause of this?

a. Trip gas
b. Connection gas
c. Background gas

7.19 You are tripping into the hole and have broken circulation. The measured gas percentage in the drilling fluid suddenly increases from 10% to 23%, before decreasing back to 10%. What type of gas is this?

a. Background gas

b. Connection gas

c. Shallow gas

d. Trip gas

7.20 While circulating after a connection, the measured gas percentage in the drilling fluid suddenly increases from 10% to 23% before decreasing back to 10%. What type of gas is this?

a. Background gas

b. Shallow gas

c. Trip gas

d. Connection gas

7.21 While the rig is drilling ahead, measured drilling fluid gas levels gradually increase, and gas-cutting is seen at the shakers. With no indications of the well flowing, what action is required?

a. This is background gas, which indicates a formation change and/or formation pressure increase. Instruct the crew to switch the vacuum degasser and prepare to increase the drilling fluid density

b. This is connection gas, which is a result from a loss of Equivalent Circulating Density (ECD) with the pumps off. Instruct the crew to line up the Mud Gas Separator (MGS) before making a connection.

c. This is recirculated air. Stop pumping and investigate the source of the air in the high-pressure fluid pumps.

d. This is trip gas which remains in the well from an earlier trip. Instruct the crew to stop operations and circulate the well until gas levels reduce.

7.22 While drilling, the Driller reports to the Supervisor that the cuttings returning to the shakers are becoming bigger and more angular in shape. The Mud logger also reports that there is a significant increase in background gas.

What should the Supervisor do?

a. Instruct the Driller to operate the vacuum degasser.

b. Instruct the Driller to reduce the Rate of Penetration (ROP) to reduce background gas levels.

c. Instruct the Driller to stop drilling, and flow check the well.

d. Instruct the Mud Engineer to increase the drilling fluid density in the active system.

7.23 While drilling along at steady state, the Derrickman asks the Driller to reduce the pump rate so that the shakers can handle an increase in cuttings in the mud returns.

What should the driller do?

a. Reduce the pump rate until the shakers can handle the capacity of cuttings in the mud returns.

b. Stop pumping and flow check. If there is no flow, continue using the original drilling parameters.

c. Stop pumping and flow check. If there is no flow, circulate bottoms up at a reduced rate so that the shakers can handle the cuttings volume.

d. Stop the pumps and flow check. If there is no flow, continue at the same rate allowing the excess to bypass the shakers and get caught in the sand traps.

7.24 While drilling, the cuttings returning to the shakers become bigger and splintered.

What should you do?

a. Communicate the kick warning sign to the Supervisor.

b. Communicate the situation to the Mud Engineer.

c. Instruct the Derrickman to change the shaker screens.

d. Instruct the Shaker Hand to by-pass the shale shakers.

7.25 While drilling, the Driller reports to the Supervisor that the cuttings returning to the shakers become splintered. What should the supervisor do?

a. This is a positive kick indicator, so instruct the Driller to shut in the well.

b. This is normal, request a change of the shaker screens.

c. This is normal, request for the return flow to by-pass the shale shakers.

d. This may be a warning sign, so communicate with the mud loggers to assess if there are other warning signs.

7.26 While drilling, the shaker hand sees that the fluid density recorded in the shale shaker house is significantly different from the fluid density in the active pit.

What action should the shaker hand take?

a. Record the fluid density change

b. Change the fluid density in the active tank

c. Inform the Driller and Mud Engineer

d. Open the by-pass valve on the shaker tanks

7.27 While drilling, the shape of the cuttings on the shaker changes and there is significant increase in gas percentage; while there is no increase in mud pits.

What should the supervisor should do with the driller?

a. Stop drilling and perform a flow check

b. Continue drilling

c. Increase Mud density.

7.28 What is the best practice from the well control point of view while RIH with casing

a. Flow check every 10 joints

b. Calculate the trip sheet using closed end displacement.

c. Monitor the closed end displacement returning on the active system.

d. Use self-filing float valve, monitor that the open end displacement is returning on trip tank

7.29 You are running a string of production casing through reservoir sections. The shoe track floats have been tested and functioned successfully at surface.

How should you monitor the well during this operation?

a. Flow check the well every 10 joints after filling the casing
b. Monitor the trip tank for the open end displacement volume and record the casing fill up volumes
c. Monitor the trip tank return volumes and compare with the calculated closed end displacement volume
d. Use the self-filling casing show track, monitor the trip tank return volumes, and compare with the calculated closed end displacement volume

7.30 After connection and while circulating bottom up circulation, it was observed that the return flow increase.

How do you explain this?

a. Blow out
b. Connection gas
c. Swabbed Kick

7.31 Trip drill takes time to be done while POOH and RIH. Why trip drill should be done?

a. To make trips faster
b. To POOH pipes more than rig hoisting capacity
c. To train crew to shut in the well with safety valve.
d. To increase ROP

7.32 As per API RP 59, which is good practice for well control drills?

a. The drill is announced, so everyone knows there is a drill
b. The drill is scheduled after the casing is drilled out.
c. The drill is scheduled when the crew changes
d. The drill should not be announced, so everyone is unaware that there is a drill

7.33 The crew must be prepared to act quickly and effectively if there is an influx.

What is one action the crew can take in advance to minimize the volume of a potential influx?

a. Build fluid volume in the active tank.

b. Continue well operations while the Pit Volume Totalizer (PVT) is offline for maintenance.

c. Run regular drills to ensure that the crew is competent.

d. Store the Drill Pipe Safety Valve (DPSV) and the crossovers in the heavy tool store.

7.34 Why do you conduct a trip drill when running in the hole?

a. To determine how long it will take to shut in the well.

b. To give you time to check the pipe tally and hole fill volume.

c. To give you time to safety grease the travelling block from a riding belt.

d. To provide the drill crew with training if there is a kick while tripping.

7.35 What is the most important reason for regular well control and emergency drills?

a. To allow supervisors to train new crew members

b. To demonstrate crew competency using well control equipment and emergency procedures

c. To function test the well control and emergency equipment

d. To meet regulations and contractual requirements.

7.36 Which action helps to prevent swabbing?

a. Installing a Non Return Valve (NRV) in the drill string.

b. Monitoring trip tank levels.

c. Pumping a heavy slug before pulling out of the hole,

d. Pumping out of the hole.

7.37 After a connection, the active pit level does not return to the same volume level as before the connection. What could this indicate?

a. Air was pumped into the well during the connection

b. The drilling fluid in the annulus is over loaded with cuttings

c. The vacuum degasser was left running during the connection

d. There was an influx during the connection

7.38 On a trip out of hole, you are about to pull non-shearable BHA components through the BOP.

Before continuing, what procedures must you follow? *(Two answers)*

a. Confirm that the crew and the rig have the ability to follow the non-shearable shut-in procedure

b. Do a flow check before non-shearable components enter the BOP

c. Function test the BOP and do a tripping well control drill

d. Have a crew tool box meeting, so that the crew pulls the non-shearable quickly

e. Secure the well before inspecting and re-testing the shear rams

7.39 During well operations, the drilling fluid becomes gas-cut.

What is the impact on the operation?

a. This is a kick warning sign, and using the vacuum degasser may complicate pit volume measurements

b. This is a warning sign, and the well must be flow checked

c. This is a positive kick indicator, the well must be shut in before notifying the supervisor, and well pressures must be recorded

d. This is normal, and will not affect ongoing operations

7.40 During well operations, the drilling fluid becomes gas-cut.

What action should be taken?

a. Divert the fluid to the waste mud pit, and continue the operation.

b. Notify the Supervisor and turn on the vacuum degasser.

c. Shut in the well, notify the Supervisor and record the well pressures.

d. Stop operations, flow check the well, and notify the Supervisor.

7.41 What is one positive indicator that the well is flowing?

a. A decrease in pump pressure

b. An increase in flow returns

c. An increase in gas-cut drilling fluid

d. An increase in torque

7.42 Which are positive warning signs of a kick while drilling? *(Two answers)*

a. A decrease in flow rate with constant pump stroke rate
b. A decrease in pit volume
c. A decrease in trip gas levels
d. An increase in flow rate with constant pump stroke rate
e. An increase in pit volume

7.43 The flow sensor shows a total loss of returns and the mud level cannot be seen in the annulus. What immediate action should be taken?

a. Shut the well in and pump lost circulation material.
b. Fill the annulus with water (or lightest mud available) and record volume.
c. Pump at reduced rate adding lost circulation material.
d. Continue drilling ahead cautiously.

7.44 What is the main role of the Driller in preventing well control incidents?

a. Taking actions to always keep the hole full.
b. Taking actions to prevent abnormal pressures.
c. Taking actions to prevent gas cut mud.
d. Taking actions to prevent lost circulation.

7.45 What should the Driller do after seeing a drilling break?

a. Circulate bottoms up.
b. Flow check the well.
c. Increase the pump speed.
d. Reduce the weight on the bit.

7.46 What should the Driller do when kick warning signs are seen?

a. Alert the Tool Pusher and request assistance.
b. Be alert to shut the well in quickly
c. Check for flow
d. Shut the well in.

7.47 Does a kick always occur after a total loss of circulation?

a. No, it depends on the mud level in the annulus and the formation pressure.
b. Yes, losses will always occur above any potential kick zone.
c. No, it depends on the reduction in drill string weight.

7.48 How will bottom hole pressure be affected by gas cut mud while drilling?

a. There will be a large drop
b. There will be no change
c. There will be a small drop

7.49 Gas cut mud may reduce the bottom hole pressure enough to cause a well kick; when is bottom hole pressure reduced most?

a. When the gas is at the bottom.
b. When the gas is near the surface.
c. When the gas is halfway up the well bore.

7.50 Which of the following is not an indicator of a kick whilst drilling?

a. Pit gain.
b. Decrease in pump strokes.
c. Decrease in pump pressure.
d. Flow rate increase.

7.51 While drilling, which of the following situations makes kick detection with a P.V.T. (Pit Volume Totalizer) more difficult for the driller?

a. By-passing the solids control equipment pits.
b. Reducing the range of P.V.T. high and low alarm settings.
c. Allowing mud losses by overflowing the shakers.
d. Keeping active mud system transfers to a minimum when drilling ahead

7.52 While drilling, which action can help you detect a kick early?

a. Allow drilling fluid losses by overflowing the shakers.
b. Allow mud system transfers from the reserve pits while drilling ahead
c. Continue operating the solid control equipment during connections
d. Reduce the range of Pit Volume Totalizer (PVT) high and low alarm settings.

7.53 Is it true that when pulling pipe out of hole, swabbing can only take place when the bit is the open hole?

a. Yes.

b. No.

7.54 While pulling out of the hole the weight indicator fluctuates due to tight spots what will be its effect?

a. Surge pressure

b. Losses

c. Swabbed kick

7.55 When pulling out of hole swabbing can be detected by comparing calculated volume with The actual volume in the trip tank

How is swabbing be detected?

a. When the hole take a less volume than calculated.

b. When the hole take a higher volume than calculated.

c. When the hole take the same volume as calculated.

7.56 The measured gas percentage in the drilling fluid increases from 8% to 9% over the past three days. What should you instruct the driller to do?

a. Increase the Weight On Bit (WOB) to compensate for the increase in gas, and stop flow checking on connections.

b. Call the mud loggers to confirm that their instruments have been calibrated within the last week.

c. Circulate bottoms up before making connections, and monitor for an increase m the gas percentage.

d. Carefully monitor for additional warning signs, as formation pressure may be increasing.

7.57 The driller stops the rig pumps to make a connection. The return flow rate in the shaker house reduces but does not stop.

What does this return mud flow indicates?

a. That the Derrickman is transferring drilling fluid

b. This is flow-back from the well

c. That there may be an influx

d. That there may be losses to the well bore.

7.58 Measured gas percentage in the drilling fluid has increased from 8% to 9% over the past 3 days. What type of gas is this?

a. Background gas

b. Connection gas

c. Shallow gas

d. Trip gas

7.59 What can cause trip gas?

a. The drilling fluid density is too heavy

b. The drilling fluid viscosity is too low

c. The hydrostatic pressure is close to the formation pressure

d. The hydro static pressure is significantly above the formation pressure

7.60 While pulling out of the hole, the driller notices that the drilling fluid required to fill the hole is less than calculated on the trip sheet. What should the Driller do first?

a. Inform the Supervisor before pumping the remaining stands out of the hole.

b. Stop tripping, inform the Supervisor, flow check, and if there is no flow, continue to pull out of the hole to surface.

c. Stop tripping, inform the Supervisor, flow check, and if there is no flow, displace a heavy slug into annulus and continue to pull out of hole.

d. Stop tripping, inform the Supervisor, flow check, and if there is no flow, run back to bottom and monitor returns.

7.61 You have been fingerprinting connections while drilling the current well section with Annular Pressure Loss (APL) 350 psi while circulating. On the last connection the drain back and the return flow where faster than had been seen previously. The well is shut-in giving a stabilized Shut In Casing Pressure (SICP) of 225 psi. There is a non-ported float in the drill string so you do not have a Shut-In Drill Pipe Pressure (SIDPP) reading. What action should you take to confirm potential kick indicator?

a. As the SICP is less than APL, open the BOP and continue with the connection.

b. As the SICP is less than APL, bleed off the SICP by 350 psi and monitor well

c. Bump the float to get SIDPP. If the SICP is greater than SIDPP, this is normal you can continue to make connection.

d. Bump the float open to get SIDPP and if there is positive pressure on the drill pipe circulate the well through the open choke.

7.62 On the following sample trip sheet, identify the first evidence of abnormal fill-up that occurred (Each stand has a calculated displacement of 2.3 bbl.)

Stand No.	Trip tank Volume at start (bbl.)	Measured Hole Fill (bbl.)	Calculated Hole Fill (bbl.)
1	51	2.3	2.3
2	48.7	2.3	2.3
3	46.4	2.3	2.3
4	44.1	2.3	2.3
5	41.8	2	2.3
6	39.8	2	2.3
7	37.8	1.8	2.3

a. When pulling Stand 1.
b. When pulling Stand 3.
c. When pulling Stand 5.
d. When pulling Stand 7.
e. Nothing wrong with fill up volumes.

7.63 On the following sample trip sheet, identify the first evidence of abnormal fill-up that occurred (Each stand has a calculated displacement of 2.3 bbl.)

Stand No.	Trip tank Volume at start (bbl.)	Measured Hole Fill (bbl.)	Calculated Hole Fill (bbl.)
1	51	2.3	2.3
2	48.7	2.3	2.3
3	46.4	2.3	2.3
4	44.1	2.3	2.3
5	41.8	2.3	2.3
6	39.5	2.3	2.3
7	37.2	2.3	2.3

a. When pulling Stand 1.
b. When pulling Stand 3.
c. When pulling Stand 5.
d. When pulling Stand 7.
e. Nothing wrong with fill up volumes.

7.64 Study the following sample trip sheet. What is the appropriate action to take according to the data?

Stand No.	Trip tank Volume at start (bbl.)	Measured Hole Fill (bbl.)	Calculated Hole Fill (bbl.)
1	51	2.3	2.3
2	48.7	2.3	2.3
3	46.4	2.3	2.3
4	44.1	2.3	2.3
5	41.8	2	2.3
6	39.8	2	2.3
7	37.8	1.8	2.3

a. Continue POOH

b. Shut-in the well and start circulation immediately

c. There is a swab in the hole, run back to bottom and circulate bottoms up

d. Discard this trip sheet and start recording in a new trip sheet

8 Well Shut-In Procedures

8.1 When running in the hole, the well begins to flow. The Driller uses the hard shut-in procedures.

What is the correct procedure?

a. Open side outlet hydraulic valve and choke.
Space out for tool joints
Close a BOP
Stab in a Drill Pipe Safety Valve (DPSV)
Close the DPSV

b. Space out for tool joints.
Close the BOP.
Stab in a Drill Pipe Safety Valve (DPSV).
Close the DPSV.
Open choke.
Record the shut-in pressure.

c. Stab in a Drill Pipe Safety Valve (DPSV)
Close the DPSV.
Space out for tool joints.
Close BOP.
Open BOP side outlet hydraulic valve.
Record the shut-in pressures.

d. Stab in a Drill Pipe Safety Valve (DPSV)
Open BOP side outlet hydraulic valve
Space out for tool joints
Close BOP Close choke
Record the shut-in pressures

8.2 When running in the hole, the Driller sees that the well is flowing. The hard shut-in procedure will be used.

Which actions should the driller take to shut the well in?

a. Make up the Drill Pipe Safety Valve (DPSV)
Close the DPSV
Close the annular preventer
Open the BOP choke line side outlet hydraulic valve Record
the pressures and kick volume

b. Make up the Drill Pipe Safety Valve (DPSV)
Open the BOP choke line side outlet hydraulic valve Space
out for tool joints
Close the BOP
Close the choke
Record the pressures and kick volume

c. Open the BOP choke line side outlet hydraulic valve and choke Space out for tool joints
Close the BOP
Install an IBOP
Record the pressures and kick volume

d. Open the BOP choke line side outlet hydraulic valve and choke Space out for tool joints
Close the BOP
Make up the Drill Pipe Safety Valve (DPSV)
Close the DPSV
Record the pressures and kick volume

8.3 After a positive flow check, the Driller uses the hard shut-in procedure to shut-in the well.

What is the correct procedure?

a. Open the BOP side outlet hydraulic valve, shut the annular or pipe rams, Close choke and monitor the shut-in pressures

b. Open the BOP side outlet hydraulic valve, shut the annular preventer, and monitor the shut-in pressures

c. Shut the annular preventer, monitor shut-in pressures, and open the BOP side outlet hydraulic valve.

d. Space out the tool joint, close the BOP (annular or ram), open the BOP side outlet hydraulic valve, and monitor pressures

8.4 How should the choke line and manifold valves be set up for the hard shut-in procedure while drilling?

a. BOP side outlet hydraulic choke line valve closed.
Choke line open through manually operated choke

Manual choke open

b. BOP side outlet hydraulic choke line valve closed.
Choke line open to remote choke

Remote choke closed

c. BOP side outlet hydraulic choke line valve closed.
Choke line open to remote choke
Remote choke open

d. BOP side outlet hydraulic choke line valve opened
Choke line open to remote choke
Remote choke open

8.5 How should the choke line and the manifold valves be set up for the soft shut-in procedure while drilling?

a. BOP side outlet hydraulic choke line valve closed.
   Remote choke closed.
   Valve upstream of the Mud Gas Separator (MGS) open.

b. BOP side outlet hydraulic choke line valve closed.
   Remote choke open.
   Valve upstream Mud Gas Separator (MGS) open.

c. BOP side outlet hydraulic choke line valve open.
   Remote choke closed.
   Valve upstream Mud Gas Separator (MGS) closed.

d. BOP side outlet hydraulic choke line valve open.
   Remote choke open.
   Valve upstream Mud Gas Separator (MGS) closed.

8.6 Why should the Driller keep the pumps running when picking up the bit to shut in on a kick?

a. To clean the bottom of the hole
b. To maximize the pressure on the bottom of the hole
c. To take an accurate slow circulating rate pressure
d. To verify the pressure losses

8.7 A vertical well with a surface BOP stack is shut-in on a kick. The pressure readings are:

SIDPP	**520 psi**
SICP	**630 psi**

What is the reason for the difference in the two readings?

a. The BOP was closed too fast and caused trapped pressure in the system.
b. The influx has a higher density than the drilling fluid.
c. The influx has a lower density than the drilling fluid.
d. The influx is already in the casing.

8.8 When there is a kick, what will be the effect of a large influx volume?

a. It will result in a higher SICP and a lower SIDPP
b. It will result in a higher SIDPP, requiring a heavier kill fluid density
c. It will result in a higher SICP but SIDPP will not be affected
d. It will result in higher SIDPP and SICP

8.9 When filling out a kill sheet, which data do you need to calculate the kill fluid density?

a. Current Mud Weight, Measured Depth (MD) and, Shut in casing pressure (SICP)
b. Current Mud Weight, Measured depth (MD), and Shut in drill pipe pressure (SIDPP)
c. Current Mud Weight, True vertical depth (TVD), and shut in casing pressure (SICP)
d. Current Mud Weight, True Vertical depth (TVD), and shut in drill pipe pressure (SIDPP)

8.10 Which value is used to calculate the kill fluid density increase required to bring the well under control?

a. Dynamic pressure loss.
b. Pit Gain.
c. Shut In Casing Pressure (SICP)
d. Shut In Drill Pipe Pressure (SIDPP)

8.11 Which factors will affect Shut in Drill Pipe Pressure? (Two answers)

a. The bit to shoe volume
b. The drilling fluid density in the string.
c. The formation pressure
d. The influx density.
e. The influx volume.

8.12 Why should space out distances for the different BOP types on the stack be posted in place where Driller can see them?

a. So the driller knows when tool joint is in the annular cavity
b. So the driller knows when tool joint is level with the flow line
c. So the driller knows when tool joint is level with the well head connection
d. So the driller knows when tool joint is in the shear ram cavity

8.13 After a kick is taken and the well shut-in, it can take 5-10 minutes or more for the pressures to build up. What affects the time for this build up?

a. Friction losses

b. Gas migration

c. Formation Porosity

d. Formation Permeability

8.14 Which of the following practice would lead to a larger influx when shutting-in a well? *(Three answers)*

a. Calling tool pusher to floor prior to shutting the well

b. Testing stab-in valves during BOP tests

c. Switching off the flow meter alarms

d. Running regular pit drills of drill crew

e. Regular briefing for the derrick man on his duties regarding the monitoring of pit level

f. Drilling a further 20 feet after a drilling break, before flow checking

8.15 The driller has shut in the well after observing an increase in then active pit level. He notes down the pressures in the following table:

Time- Minutes	Drill Pipe	Casing
After 3 minutes	160	210
After 6 minutes	195	265
After 9 minutes	210	290
After 12 minutes	220	300
After 15 minutes	230	310

Which one of the following options is correct, if the supervisor wants to calculate the density of the kill fluid?

a. Use annulus pressure of 290 psi because the increase in the following periods is caused by gas migration.

b. Use the drill pipe pressure of 210 psi because the increase in the following periods is caused by gas migration.

c. Ask the driller to continue taking pressure, until the drill pipe does not increase any further.

d. Use the drill pipe pressure gauge of 160 psi. The continuous pressure increase in the following periods in caused by gas migration.

8.16 A well has kicked, and is shut in. There is a float valve in the drill string and drill pipe gauge reads zero. Before the gas start to migrate which of the following will be used to determine the kill density required to kill the well?

a. Start circulation at a slow circulation rate. Read initial circulating pressure, and Ignoring string pressure losses, assume initial circulating pressure = shut in drill Pipe pressure use this pressure to calculate the kill mud density

b. Assume that gas gradient is 0.1 psi/ft. which together with the influx volume will be used to determine the formation pressure and kill mud weight

c. Start pumping very slowly in to the drill pipe with the well shut in. When the float valve has opened, stop the pump. The pressure the on the drill pipe pressure gauge = shut in drill pipe pressure. Use this pressure to calculate the kill mud density.

8.17 You are displacing cement with drilling fluid using the cement unit, when the well starts to flow. Which action should you take to ensure well safety?

a. Continue to pump at the maximum rate until the cement is in place, as this will kill the well.

b. Shut down the cement unit, close the annular preventer, and disconnect the cement line from the casing water bushing to isolate the cement unit

c. Shut down the cement unit, close the annular preventer, monitor the pressures at choke manifold and at the cement unit.

d. Shut down the cement unit, close the shear rams and monitor the pressures at choke manifold.

8.18 After POOH first stand off bottom, the well started flowing. Well is shut in, secured with FOSV on top of drilling string and you have flapper valve in the string. What driller should do before killing the well?

a. Install IBOP and makes up TDS and strip back mean-while adjusting annular closing pressure.

b. Install IBOP and open FOSV, prepare to stirp back to bottom.

c. Install IBOP and open FOSV, pump slowly to open flapper valve get SIDPP and calculate kill mud.

d. Make up TDS and open FOSV, start pump back to bottom.

8.19 There is a kick while tripping the first stand off bottom and the well is securely shut in with DPSV installed and closed. The drill string contains a functional flapper valve. What would you need to do before killing the well?

a. Install an IBOP, make up the top drive, open DPSV, adjust the annular closing pressure and strip back to bottom.

b. Make up the top drive, open the DPSV, pump open the flapper valve, record SIDPP and calculate KMW.

c. Make up the top drive, open DPSV and pump back to bottom, record SIDPP and calculate KMW

d. Use the SICP and kick volume to estimate kill fluid weight.

8.20 After running casing, and upon circulating mud, the driller noticed increase in returns. Which action should the driller take to ensure well safety?

a. Continue to proceed in cementing operation

b. Stop circulation, close the annular preventer, and then circulate through water bushing.

c. Stop circulation, close the shear rams and monitor the pressures at choke manifold.

d. Stop circulation, close the annular preventer, install FOSV & IBOP and record pressures.

8.21 If the annulus was loaded by cutting, how will this affect SICP?

a. Increase

b. Decrease

c. Has no effect

9 Well Killing Procedures

9.1 When should the Driller take kill rate circulating pressures? ***(Two answers)***

a. At beginning of each shift.

b. Every time the fluid density is changed.

c. Immediately before running casing.

d. Only after drilling out the casing shoe.

e. Only after reaching Total Depth (TD)

9.2 A driller comes on shift while the rig is drilling ahead. The section will be drilled ahead to Total Depth (TD) just above the reservoir and the TD may be reached during the Driller in shift.

What should the Driller do at the start of this shift?

a. Continue to drill ahead, as recording the new Kill Rate Circulating Pressures in not required

b. Stop the pumps and flow check the well

c. Take new Kill Rate Circulating Pressures

d. Wait a further six hours then take Kill Rate Circulating Pressures.

9.3 What is the primary reason for choosing to circulate out a kick at a slow rate?

a. To allow the gas to expand.

b. To avoid exceeding the surface equipment handling limitations including the Mud Gas Separator (MGS)

c. To prevent choke washout.

d. To prevent formation washout at bit depth

9.4 Select the reason for circulating out a kick at a slow pump rate.

a. Prevent gas expansion as it is circulated up the well.

b. Allow Annular Pressure loss to maintain a high overbalance.

c. Minimize excess pressure exerted on formations during the kill.

9.5 Before drilling out the surface casing shoe, why are circulating pressures taken at different kill rates?

a. To circulate the kill and choke lines to clean water

b. To establish a safe kill rate to minimize the effects of ECD

c. To establish the required tank levels to kill the well

d. To establish the capacity of the kill pump

9.6 Which of the following parameters should be considered when selecting the pump rate for killing the well?

a. The depth of casing shoe

b. The Mud Gas Separator (MGS) capacity

c. The size of the casing

d. The vacuum degasser capacity

9.7 What conditions determine the selection of the kill rate circulating rate? (Four answers)

a. The burst pressure of the casing

b. Annular friction losses during the kill operation

c. The kill mud mixing capacity

d. The volume handling capacity of the choke

e. The mud/gas separator handling capacity

f. The volume of mud in the trip tank

9.8 Which of the following statements about slow circulating rates (SCR) are correct? *(Three answers)*

a. SCR's should be taken through the choke manifold.

b. SCR's are needed to calculate formation pressure

c. SCR's should be taken when mud properties are changed.

d. SCR's should be read on the drill pipe pressure gauge at the remote choke panel.

e. SCR's should be taken with the bit near the bottom

9.9 How do you measure the slow circulating rate pressure losses?

a. Close the BOP and then pump through the choke manifold and degasser to the shale shakers taking your returns through a fully open choke. Read the pressure off the drill pipe pressure gauge at the Driller's console.

b. Line up the cement pump to circulate round the well at pre-determined reduced rates through an open BOP to the flowline. Read the pressure off the cement unit chart recorder.

c. Line up the mud pumps to circulate down the drill string and up the annulus taking returns through and open BOP to the flowline. Read the pressure off the drill pipe pressure gauge at the remote choke panel.

d. Line up the mud pumps to circulate the well across the top of a closed BOP, taking returns to the flowline. Read the pressure off the drill pipe pressure gauge at the remote choke panel.

9.10 How to measure SCR/RRCP?

a. Turn on the pump at a slow speed with moving and rotating the pipe, Records the pressure readings from the remote choke panel.

b. Turn on the pump at a slow speed without moving or rotating the pipe. Records the pressure readings from the remote choke panel.

c. Turn on the pump at a slow speed without moving or rotating the pipe, Records the pressure readings from the driller console

d. Turn on the pump with maximum speed without moving or rotating the pipe, Records the pressure readings from the choke panel

9.11 Why it is important to monitor trends in pit volume during a well control operation? *(Two answers)*

a. To adjust the pump rate

b. o adjust the drill pipe pressure

c. To check for mud losses

d. To maintain Bottom Hole Pressure (BHP) constant

e. To monitor the gas expansion

9.12 While killing the well using 30 SPM, the back pressure inside the separator will reach the maximum operating pressure of the mud seal. What can be done?

a. Increase pump rate

b. Shut in the well and bleed the casing pressure

c. Shut in the well establish new circulation rate

d. Shut in the well

9.13 When drilling a horizontal section of a well a gas kick is taken and the well shut in. If the influx is in the horizontal section what would you expect the SIDPP and SICP to be?

a. Both are about the same.

b. SICP is much greater than the SIDPP.

c. SIDPP is much greater than the SICP.

d. SIDPP will be zero.

9.14 The SIDPP is used to calculate:

a. Formation pressure

b. Formation fracture pressure

c. Shoe pressure

d. Hydrostatic pressure

9.15 While circulating a gas kick, how to detect mud losses?

a. Monitor gas expansion trend on the active tanks/ Pit deviation.

b. Monitor trip tanks.

c. Follow the flow sensor.

d. Monitor the u-tube pressure gauge.

9.16 How is lost circulation detected during a well control operation? (Three answers)

a. An unexpected requirement to close the choke to maintain the drill pipe pressure.

b. By monitoring annulus and drill pipe pressures against predicted values.

c. By monitoring the drilling fluid density.

d. By monitoring the drilling fluid volume in the mud tanks against predicted values.

e. By monitoring the flowline flow rate indicator against the predicted values.

f. By monitoring the trip tank levels.

g. By monitoring the U-tube pressure gauge.

9.17 H2S is released during a well control incident. What is the risk to personnel?

a. The risk is minor as H2S has low toxicity and is lighter than air.

b. The risk to personnel is minor but the release will have a major impact on the environment.

c. The risk to personnel is high as H2S released is highly toxic and heavier than air

d. There is no risk as H2S is nontoxic and can be released without risk

9.18 A well is shut in on a surface BOP installation, and the pressure reading are:

Shut in Drill Pipe Pressure (SIDPP): 435 psi

Shut in Casing Pressure, (SICP): 0 psi

What is the most likely reason for this SICP?

a. The drill string has twisted off.

b. The formation at the shoe is fractured

c. The hole is packed off around the Bottom Hole Assembly (BHA)

d. The well is swabbed in

9.19 The Driller shuts on a kick

Well Data:

Shut in Drill Pipe Pressure (SIDPP): 800 psi

Shut in Casing Pressure (SICP): 1100 psi

Kill rate circulating pressure: 500 psi at 40 SPM

While the Driller brings the pump to 40 SPM, which pressure should be held constant to maintain the correct Bottom Hole Pressure (BHP)?

a. 1100 psi at the casing gauge

b. 1300 psi at the drill pipe gauge

c. 1600 psi at the casing gauge

d. 800 psi at the drill pipe gauge

9.20 How would you determine the Initial Circulating Pressure (ICP) on surface stack BOP when the kill rate circulating pressure is unknown?

a. Add 1000 psi to the Shut In Drill Pipe Pressure (SIDPP) and circulate out the kick

b. Add 400 psi to the casing pressure and bring the pump up to kill rate while using the choke to keep the casing pressure constant.

c. Bring the pump speed up to kill rate while keeping the casing pressure constant.

   This circulating pressure equals the ICP

d. Circulate at the desired SPM to circulate out the kick, but hold 200 psi back pressure on the drill pipe side with the choke.

9.21 A kick is shut in on a surface BOP stack. No kill rate circulating pressures are available.

What procedure should be used to determine the correct Initial Circulating Pressure (ICP)?

a. Check the records and use the kill rate circulating pressure the Driller recorded when the previous BHA was closest to the kick depth. Add a safety margin as a precaution.

b. Contact the Mud Logger and request an estimate of the ICP to kill the well.

c. Use the Driller's Method as the drill pipe pressure does not change during circulation and the Shut In Casing Pressure (SICP) can be used to maintain constant ICP

d. When starting to kill the well, keep the choke pressure to the Shut In Casing Pressure (SICP) as possible. When the selected kill pump rate is reached, read the drill pipe pressure and use it as the ICP.

9.22 During well kill operations, what will happen when bringing the pumps up to kill speed if the casing pressure is allowed to increase above Shut In Casing Pressure (SICP)?

a. Down hole pressure would decrease and may cause more of the influx to enter the well bore.

b. Down hole pressure would increase and may exceed the formation fracture pressure.

c. The drill pipe pressure will decrease and may allow more of the influx to enter the well bore.

d. The increase SICP will have no effect on bottom hole pressure.

9.23 During a kill operation there is a delay between operating the choke and observing a change in the drill pipe pressure.

What is the "rule of thumb" for the rate of pressure transmission through a drilling fluid?

a. 3-5 seconds.

b. 750 feet/minute.

c. 1 minute per 1000 feet of travel.

d. 1 second per 1000 feet of travel.

9.24 Why is it important to monitor the pit volume during well control? *(Two answers)*

a. To maintain bottom hole pressure constant.

b. To adjust drill pipe pressure

c. To adjust pump rate

d. To follow the gas expansion

e. To check for mud loss

9.25 Which action is required to maintain constant bottom-hole pressure when starting and stopping circulation?

a. The drill pipe pressure should be kept constant while bringing the pumps up to kill speed.

b. The pumps must be brought up to speed holding the casing pressure constant.

c. The pumps must be brought up to speed while increasing the casing pressure by a safety margin above the original Shut In Casing Pressure (SICP)

d. The pumps must be brought up to speed while increasing the drill pipe pressure by a safety margin above the original Shut In Drill Pipe Pressure (SIDPP)

Driller's Method

9.26 When circulating a gas kick from a well using the Driller's Method, what happens to the casing shoe pressure when the influx passes the casing shoe?

a. The casing shoe pressure will decrease

b. The casing shoe pressure will increase.

c. The casing shoe pressure will stay the same.

9.27 During the second circulation of the Driller's Method (no influx in the annulus), what happens to the casing pressure while kill fluid is pumped to the bit?

a. Casing pressure will decrease

b. Casing pressure will increase

c. Casing pressure will remain constant.

9.28 A gas kick is being circulated out on a surface BOP installation using the Driller's Method. What happens to the Bottom Hole Pressure (BHP) if the casing pressure is held constant while the gas is being circulated from the bottom of the hole to surface?

a. The BHP decreases

b. The BHP does not change

c. The BHP increases

9.29 During a well kill operation, using the Driller's Method, the choke pressure suddenly increase 150 psi.

After a short time, the operators sees a 150 psi pressure increases on the drill pipe gauge.

What is the correct action to take?

a. Reduce the pump rate to decrease both pressures by 150 psi

b. Shut in the well, and change to another choke.

c. Shut in the well, and change to the spare standpipe.

d. This is normal, continue with the operation.

9.30 An influx is shut in on a surface BOP installation, and the initial stabilized shut- in pressures are:

Shut in drill pipe pressure (SIDPP):	**500 psi**
Shut in casing pressure (SICP):	**900 psi**

After the first circulation of the Driller's method is completed, the well is shut in and the pressures are allowed to stabilize:

SIDPP:	**500 psi**
SICP:	**650 psi**

What should the driller do?

a. Bullhead the annulus until SICP is reduced to 500 psi

b. Continue with second circulation of Driller's Method, holding casing pressure constant until fluid reaches the bit.

c. Start circulation using Wait and Weight Method.

d. Reverse circulate until SICP is reduced to 500 psi.

9.31 While displacing the well with kill fluid during the second circulation of the Driller's method when the Final Circulating Pressure (FCP) be reached?

a. After kill fluid reaches the bit.

b. Once the influx is circulated out of the hole.

c. When kill fluid reaches the casing shoe.

d. When kill fluid is pumped down the drill string.

9.32 A gas kick is being circulated out using the Drillers Method.

What will happen to the bottom hole pressure if the gas bubble is not allowed to expand as it is circulated up the hole?

a. It will increase

b. Stay the same

c. It will decrease

9.33 The Driller's Method is used to kill the well. At the start of the second circulation, what is the correct process to take?

a. Circulate drill string and annulus with kill fluid while maintaining a constant casing pressure

b. Circulate the annulus with kill fluid while maintaining a constant casing pressure

c. Circulate the drill string and annulus with kill fluid while maintaining a constant drill pipe pressure

d. Circulate the drill string with kill fluid while maintaining a constant casing pressure

9.34 During the second circulation of the Driller's Method, which actions must be taken? *(Two answers)*

a. Adjust the choke to maintain drill pipe pressure constant, while the kill fluid is pumped from the bit to surface.

b. Adjust the choke to maintain casing pressure constant, until kill fluid reaches the bit

c. Adjust the choke to maintain drill pipe pressure constant, until kill fluid is at the bit

d. Adjust the choke to maintain casing pressure constant, while circulating kill fluid from the bit to surface

e. Shut the well in. Check the annular and standpipe pressures are approximately equal to the original Shut-in Drill Pipe Pressure (SIDPP) after kill fluid has reached the bit.

9.35 When circulating a gas kick from a well using the Driller's Method. What happens to the casing shoe pressure when the influx has passed the casing shoe?

a. The casing shoe pressure will decrease.

b. The casing shoe pressure will increase.

c. The casing shoe pressure will stay the same.

Wait and Weight Method

9.36 Which of the following pressures should be maintained while bringing up the pump to kill rate (in Weight and weight method)

a. Drill pipe pressure

b. Casing pressure

c. Drill pipe on schedule.

9.37 A gas kick is circulated out on a surface BOP installation using the Wait and Weight Method.

What will happen to the Bottom Hole Pressure (BHP) if Strokes Per Minute (SPM) are decreased while holding casing pressure constant until new SPM are reached? (Ignore pressure losses in the annulus)

a. It will decrease

b. It will increase

c. It will stay the same

9.38 A gas kick is circulated out on a surface BOP installation using the Wait and Weight Method. What will happen to the Bottom Hole Pressure (BHP) if the drill pipe pressure is held constant while the kill fluid is pumped to the bit?

a. The BHP increases

b. The BHP decreases

c. The BHP does not change

9.39 A vertical well on a surface BOP installation is killed using the Wait and Weight Method. Initially, a quantity of original drilling fluid pumped down the well instead of kill fluid. The quantity pumped is equivalent to a volume of 1000 ft. of drill pipe.

a. Bleed off the pressure from the drill pipe until pumped volume is returned

b. Ignore it, this mistake will only have a small effect on bottom hole pressure

c. Increase the back pressure by the equivalent difference in drilling fluid hydrostatic.

d. Stop the pump and shut the well in. Evaluate pressures, reset stroke counter and restart circulation

9.40 In which situation, would the Wait and Weight Method give lower casing shoe pressure than Driller's Method?

a. The pressure at the casing shoe is always lower when using the Wait and weight

b. When the cased annular is equal to the open-hole annular volume.

c. When the drill string volume is greater than the annulus open hole volume

d. When the drill string volume is less than the annulus open-hole volume.

9.41 What actions can be taken to minimize pressure in the annulus during the kill operation if the drill pipe volume is less than the open-hole volume? *(Two answers)*

a. Choose a higher circulating rate

b. Choose a lower circulating rate

c. Maintain extra back-pressure on the choke for safety

d. Use the Driller's Method

e. Use the Wait and Weight Method

9.42 Why is the Wait & Weight method preferred over the Driller method?

a. Driller's method is prohibited in weak formation zones

b. Because Wait & Weight method is faster than Driller's method

c. Because the Wait & Weight method reduces the risk of formation fracture and losses

d. Wait & Weight can be started while the Derrick man prepare the kill mud

9.43 What is an advantage of using the Wait and Weight Method compared to the Driller's Method?

a. It allows the circulation to start immediately

b. It creates lower surface pressures

c. It increases the chance of gas migration

d. It takes less time to prepare heavy kill fluid

9.44 What is an advantage of using the Driller's Method compared to the Wait and Weight Method for a well control operation?

a. It requires no calculations before starting the operation

b. It results in a lower casing shoe pressure

c. It results in lower surface pressure

d. It takes less time to complete

9.45 Which statement is correct when comparing the Driller's Method to the Wait and Weight Method?

a. The Driller's method gives a lower choke pressure than the Wait and Weight Method

b. The Driller's method kills the well quicker than the Wait and Weight Method

c. The Driller's method removes the influx from the well quicker than the Wait and Weight Method

d. The Wait and Weight Method removes the influx from the well quicker than the Driller's Method

9.46 On a surface BOP installation, which actions should be taken while killing a well using the Wait and Weight Method? (Two answers)

a. Adjust the choke to hold casing pressure constant while kill fluid is pumped from surface to the bit.

b. Adjust the choke to hold casing pressure constant while kill fluid id pumped from the pump to the standpipe

c. Adjust the choke to hold the casing pressure constant while pump is brought up to kill speed

d. Adjust the choke to hold the drill pipe pressure constant while the kill fluid is pumped from the surface to the bit

e. Adjust the choke to hold the drill pipe pressure constant while kill fluid is pumped from bit to surface at a constant pump rate

9.47 While killing well using the Wait and Weight Method, a constant pump rate is used to displace the drill string to kill fluid, The Drill Pipe Pressure suddenly drops.

What is the safest action to do?

a. Increase the pump rate

b. Shut in the well, and prepare a new drill pipe pressure schedule.

c. Close the choke to compensate for the pressure loss.

d. Continue the operation at the same pump rate.

9.48 On a surface BOP installation, the Supervisor uses the Wait and Weight Method to circulate out a gas kick.

What will happen to the Bottom Hole Pressure (BHP) if the drill pipe pressure is kept constant when kill fluid being pumped to the bit? (Ignore pressure losses in the annulus)

a. BHP will decrease

b. BHP will increase

c. BHP will stay the same

9.49 You are working on a rig that has a large surface line volume (from the mud pumps to the drill floor). How will this affect the time it takes to kill the well using the Wait and Weight Method?

a. The total time it takes to kill the well will not be affected.

b. The total time to kill the well will be longer than calculated.

c. The total time to kill the well will be shorter than calculated.

9.50 You are working on a rig that has a large surface line volume (from the mud pumps to the drill floor). If the pump stroke counter is reset to zero when starting to pump for the Wait and Weight method, how will this affect the Bottom Hole Pressure (BHP)?

a. The BHP will decrease

b. The BHP will increase

c. The BHP will not be affected

9.51 A kill operation is ready to start, using the Wait and Weight Method.

Kill fluid is ready to be pumped, but it takes 20 bbl. to fill the surface lines.

What is the correct procedure to follow?

a. Add the 20 bbl. (converted to pump strokes) to the total strokes to be pumped

b. No action is required, there will be no effect on the drill pipe pressure schedule

c. Re-set the stroke counter to zero when kill fluid reaches the drill pipe

d. Subtract the 20 bbl. (converted to pump strokes) from the total strokes to be pumped.

9.52 Which kill method minimizes the pressure generated in the annulus?

a. The Bullheading method.

b. The Driller's method.

c. The Volumetric method.

d. The Wait and Weight method.

9.53 What will happen if we ignore a large surface line volume (from the mud pumps to the drill floor) when preparing a kill sheet for a Wait and Weight Method kill? *(Two answers)*

a. The drill pipe pressure schedule will result in a bottom-hole pressure that is too low.

b. The total time to kill the well will be shorter than calculated.

c. The total time to kill the well will be longer than calculated.

d. The drill pipe pressure schedule will result in a bottom-hole pressure that is too high.

e. There will not effect on the bottom hole-pressure.

9.54 Well with a long open hole section, which kill method will minimize the pressure at the casing shoe?

a. Bull-heading method

b. Driller's method

c. Volumetric method

d. Wait and Weight method.

Pressures during Killing

9.55 After closing in the well successfully, both SIDPP and SICP increased due to migration. How is the BHP affected?

a. The will BHP stay the same

b. The BHP decrease by the same rate of increase as SIDPP and SICP

c. The BHP increase by the same rate of increase as SIDPP and SICP.

9.56 There is a gas kick and the well is shut in with no float in the drill string. Due to power failure on the rig, the kill operation is delayed. As a result, the influx begins to migrate. What will happen to the drill pipe pressure and casing pressure?

a. Both the drill pipe pressure and casing pressure increase, but the drill pipe pressure increases more than the casing pressure.

b. Both the drill pipe pressure and casing pressure increase by approximately the same amount.

c. Both the drill pipe pressure and casing pressure increase, but the casing pressure increases more than the drill pipe

d. The drill pipe pressure and the casing pressure are not affected by the gas migration.

9.57 While drilling ahead, a well kicks and is shut in. The Shut In Drill Pipe Pressure (SIDPP) and Shut In Casing Pressure (SICP) begin to increase and then suddenly the SICP drops, followed by a sudden drop in SIDPP.

Which may have happened?

a. A weak formation has broken down

b. Gas has started to migrate up the well bore.

c. The bottom hole assembly has packed off

d. The drill string has washed out.

9.58 When circulating out a kick using the Driller's method and keeping bottom hole pressure constant, the annulus pressure decreases before gradually increasing. What could have caused this?

a. A change in pump rate

b. A reduction in influx height

c. A washout in the choke

d. A washout in the drill string

9.59 At what stage of a kill operation can choke pressure readings exceed MAASP without breaking down the shoe

a. When the influx is on bottom.

b. As kill fluid is circulated to the bit

c. When the influx is above the casing shoe.

d. When the influx is in the open hole section

9.60 A kick is circulated out at 40 SPM, Drill pipe pressure is 650 psi and the casing pressure is 1050 psi. The pumps are slowed to 30 SPM while maintaining 1050 psi on the casing gauge. How will this affect Bottom Hole Pressure (BHP)?

(Exclude any Equivalent Circulating Density (ECD) effects).

a. BHP will decrease

b. BHP will stay the same

c. BHP will increase

9.61 During a kill operation the choke is adjusted to increase drill pipe pressure by 200 psi while pump speed is maintained at a constant 35 SPM.

What will happen to the casing pressure?

a. Casing pressure will decrease.

b. Casing pressure will increase.

c. Casing pressure will stay the same.

9.62 While killing a well, the pump speed is increased while the Bottom Hole Pressure (BHP) is kept constant. What will happen to the casing pressure?

a. Casing pressure will decrease

b. Casing pressure will increase

c. Casing pressure will remain the same

9.63 During a kill operation, the pump rate is increased and the choke is adjusted, while holding the casing pressure constant. If the influx is above the casing shoe, how will this change in pump speed affect the casing shoe pressure? (Assume annular friction losses are zero)

a. Casing shoe pressure will decrease

b. Casing shoe pressure will increase

c. Casing shoe pressure will remain constant

9.64 Kill fluid is being circulated down the drill string in a horizontal well.

As the kill fluid reaches the start of the 2000 feet long horizontal section circulation is stopped and the well secured. What should the Shut In Drill Pipe Pressure (SIDPP) read?

a. Kill fluid density divided by original mud density x 2000 feet x 0.052

b. The same as the original SIDPP

c. The same as the Shut In Casing Pressure (SICP)

d. Zero

9.65 A fresh water kick (with no associated gas) is circulated out of a vertical well with water-based drilling fluid.

When will the surface casing pressure reach its maximum?

a. Immediately after the well is shut in and pressures stabilize.

b. Just after the kill fluid reaches the bit

c. Only when the kick reaches the casing shoe

d. When the kick is circulated out to surface

9.66 While circulating out a kick, it was required to increase pump rate from 30 SPM to 40 SPM. What will happen to BHP?

a. Increase

b. Decrease

c. Stay the same

Well Killing Problems

9.67 What will happen to bottom hole pressure if you decrease the pump speed (SPM) while holding drill pipe pressure constant?

a. Increase

b. Decrease

c. Remains Steady

9.68 After a check trip at 9854 ft. with 10.3 ppg drilling fluid, circulation is started at a constant pump rate and there is an increase in returns. The well is shut-in with zero pressure on the drill pipe gauge and 200 psi on the casing gauge. There is no float in the drill string. What kill mud density will be required?

a. 10.3 ppg

b. 10.7 ppg

c. 11.3 ppg

d. There is no way of knowing

9.69 When circulating out a kick, the Top Drive System (TDS) high-pressure fluid hose develops a leak.

What should the driller do?

a. Close the shear rams, and shear-off the drill string

b. Disconnect the TDS, install a Full Opening Safety Valve (FOSV) on the drill string, close the FOSV and then close the choke

c. Drop the drill string, and close the blind/shear rams

d. Stop the pump, close the lower TDS well control valve, and then close the choke.

9.70 During a well kill operation using the Driller's Method, the choke pressure suddenly increases by 150 psi.

After a short time, the operator sees the same pressure increase on the drill pipe pressure gauge.

What is the most likely cause of this pressure increase?

a. A plugged nozzle in the bit

b. A second influx has entered the well

c. A wash out in the drill string

d. The choke is partly plugged

9.71 During a well control operation, the Supervisor sees that the Shut In Casing Pressure (SICP) is rapidly increasing, and tells the Driller to shut down the pumps quickly, to prevent over-pressuring the open hole.

What problem may have caused the rapid increase in SICP?

a. A lost bit nozzle

b. A plugged bit nozzle

c. A plugged choke

d. A washout in the drill pipe

9.72 During killing the well there is a failure in the mud pump, what is the correct action should be taken?

a. Without shutting in the well, start another pump quickly

b. Use volumetric method immediately

c. Try to keep the Drill Pipe pressure constant

d. Shut the well-in

9.73 While circulating out a kick, the mud pump fails.

What should the Driller do?

a. Change over to another mud pump.

b. Divert the well.

c. Fix the mud pump as soon as possible.

d. Shut in the well.

9.74 While circulating out a kick, the choke line between the hydraulic side outlet valve and the choke manifold breaks. What action should be taken?

a. Stop the pumps and close the BOP side outlet hydraulic valve

b. Stop the pumps and close the choke

c. Stop the pumps and close the shear rams

d. Stop the pumps and re-route through the kill line

9.75 While circulating in a well control situation, there are signs from the liquid seal pressure indicator in the Mud Gas Separator (MGS) that the mud seal is being lost. What is the appropriate procedure to take?

a. Continue pumping at the established flow rate and close-in the choke to reduce gas flow. Re-establish the MGS seal levels through the hot-line. Continue well control operations while monitoring the MGS pressures

b. Stop pumping, and safely shut in the well. Re-establish the MGS seal level through the hot-line. Continue well control operations while maintaining bottom hole pressure with a new reduced flow rate. Continue to monitor well and MGS pressures.

c. Continue pumping at the established flow rate and open the manifold blow down line to reduce the gas flow to the MGS. Re-establish the MGS seal levels through the hot-line. Continue well control operations while monitoring the well and MGS pressures.

d. Stop pumping, and re-establish the MGS mud seal level through the hot-line. Continue well control operations while maintaining bottom hole pressure with a new reduced flow rate. Continue to monitor the well and MGS pressures.

9.76 The Driller's method is used to kill a well. The drill pipe pressure is 870 psi at 30 SPM.

The pressure inside the Mud Gas Separator (MGS) is increasing and the Driller decides to reduce the pump rate.

What is the effect on the Bottom Hole Pressure (BHP) if 870 psi on the drill pipe gauge is kept constant while the pump rate is reduced?

a. BHP will increase

b. BHP will not change

c. BHP will decrease

9.77 While killing a well, the drill string is displaced to kill mud at a constant pump rate. There is a sudden loss in standpipe pressure, but no change in the casing pressure.

If the choke was closed to compensate for the reduction in pressure, how would this effect Bottom Hole Pressure (BHP)?

a. BHP would decrease

b. BHP would increase

c. BHP would remain constant

9.78 During a well kill operation, a washout develops in the drill string. What action is required?

a. Pump Lost Circulation Material (LCM)

b. Shut in the well and assess the situation

c. Switch to bull-heading

d. Switch to reverse circulate

9.79 How would you recognize a choke washout?

a. A rapid increase in casing pressure with no change in drill pipe pressure.

b. An increase in drill pipe pressure with no change in casing pressure

c. Drill pipe pressure and casing pressure both decrease, despite closing the choke

d. Drill pipe and casing pressure both increase, despite opening the choke

9.80 What is the safest action to take in a well kill situation if there is a washout in the drill string, with the influx below the washout?

a. Increase the pump rate to its maximum until the influx is above the washout.

Then reduce the pump rate to the original kill rate

b. Pump Lost Circulation Material (LCM) at the maximum pump rate until the influx is above the washout. Then continue with the well kill operation

c. Stop pumping. Follow volumetric stripping control procedures and strip out of the hole to locate the washout in the drill string. Replace washed out joint(s) and complete well kill with the bit off bottom.

d. Stop pumping. Use the Volumetric Method until the influx is below the BOP. Begin to lubricate fluid into the well, and bleed off the influx

9.81 On an offshore jack-up rig, a gas kick is being circulated out from the well.

The choke operator sees a significant pressure increase on the kill line gauge, and then sees a pressure increase on the drill pipe gauge. The choke line gauge shows no significant changes. What has happened to the circulating system?

a. On a jack-up rig, these pressure changes are normal, and caused by rig heave.

b. There is a partial blockage in the choke line.

c. There is a partial blockage in the open-hole section, caused by balled-up stabilizers.

d. There is a partial or complete blockage in the kill line.

9.82 During the second circulation of the Driller's Method with the kill fluid in the open-hole annulus, the drill pipe pressure starts to increase, and then does not respond to choke adjustment. What is the most likely cause?

a. A bit nozzle has become plugged

b. Annular friction has increased

c. The annulus has become packed-off

d. The pump speed has increased

9.83 While starting a well kill, the remote choke become stuck in the open position.

Which action is required?

a. Decrease the pump rate to allow time to open the manual choke.

b. Increase the pump rate to increase the annular friction losses.

c. Stop the pump and close a valve upstream of the choke.

d. Without stopping the pump, change over to the manual choke.

9.84 During a kill operation, minor losses are experienced. What could you do to reduce the pressure at the loss zone?

a. Reduce mud viscosity.

b. Stop circulation and shut in the well. Allow the influx to migrate to surface using the Volumetric Method.

c. Reduce pump speed and keep bottom hole pressure as close to formation pressure as possible.

9.85 With the BOP closed on a live well, you can activate a 'secondary seal' on a ram type preventer in an emergency.

Which pressure it will seal against?

a. The closing chamber pressure

b. The opening chamber pressure

c. The operating pressure

d. The wellbore pressure

9.86 During a routine test, you see that the weep hole (drain hole/vent hole) on one of the ram type BOP bonnets is leaking drilling fluid. What action is required?

a. Energize the emergency packing. If the leak stops, leave it until the next maintenance schedule.

b. The primary ram shaft seal is leaking, secure the well and replace it immediately.

c. The ram packing elements on the ram body are worn out, replace them immediately.

d. The weep hole only checks the closing chamber seals, leave it until the next maintenance schedule.

9.87 After a round trip at 9100 ft. with 11.6 ppg drilling fluid circulation is started while circulation, there is an increase in returns. The well is shut in with zero on the drill pipe gauge and 300 psi on the casing gauge.

If there is no float in the string. What kill mud density will be required to kill the well?

a. 10.3

b. 11.6

c. 12.3

d. 12.5

9.88 While circulating out a kick the mud pump fails. What should the Driller do?

a. Change over to another mud pump

b. Divert the well

c. Fix the mud pump as soon as possible

d. Shut in the well

9.89 What will be affected by having a wash out in the string while killing a well? (Two answers)

a. Final circulating pressure (FCP)

b. Formation pressure

c. Reduced rate circulating pressure (RRCP)

d. Fracture pressure

e. Kick tolerance

Volumetric Method/Stripping

9.90 Shortly after starting the first circulation of the Driller's Method, the drill pipe becomes plugged and you cannot circulate or read the drill pipe pressure. You have indications that the gas kick is migrating.

Which well control procedure should you apply?

a. Reverse circulation

b. The Driller's Method

c. The Volumetric Method

d. The Wait and Weight Method

9.91 You are using the Volumetric Method to control a gas influx in a vertical well bore.

When will be the maximum pressure at the casing shoe be reached? *(Two answers)*

a. When the bottom of the gas reaches the casing shoe.

b. When the top of the gas reaches surface.

c. When the top of the gas reaches the casing shoe.

d. When the well is initially shut in.

9.92 With a ported float installed, what might happen if gas migrates after the pressures have been stabilized?

a. Both drill pipe and annulus pressures will increase.

b. Only the annulus pressure will increase.

c. Only the drill pipe pressure will increase.

d. Shut in pressures will remain constant.

9.93 After shutting in the well for a long time without starting circulation, both SIDPP and SICP started to rise. What is the main cause of the rising pressures?

a. Gas migration in the drill pipe and the annulus

b. Gas migration in the annulus

c. Gas migration in the drill pipe

d. Gas Expansion

9.94 While drilling, there is a 10 bbl. gas kick and the well is shut in with the bit on bottom the pressures at surface stabilizes after a few minutes. Due to problems with the pumps, the kill operation cannot start. After an hour, the pressures at surface increase because of gas migration.

What action is required to keep the bottom-hole pressure constant? (Assume there is no float valve in the string)

a. Bleed off the drilling fluid at the choke, keeping the casing pressure constant

b. Bleed off the drilling fluid from the choke to reduce the drill pipe pressure to the original Shut In Drill Pipe Pressure (SIDPP)

c. No action is required as gas migration will not affect the bottom hole pressure

d. Start bleeding off the drilling fluid at the choke, and allow the casing pressure be reduced to the original Shut In Casing pressure (SICP)

9.95 Which one of the following best describes the purpose of the "volumetric method" of well control

a. It allows the influx of migrate to surface while maintaining pressure in the influx more or less constant

b. It allows the influx to migrate to surface under control while maintaining bottom hole pressure close to constant

c. It allows the influx to migrate to surface while maintaining casing pressure at its initial values

d. It allows the influx to migrate to surface while maintaining the casing shoe pressure more or less constant

9.96 What is the purpose of the Volumetric Method?

a. To maintain a constant influx bubble pressure as it rises up the well bore

b. To maintain a constant casing pressure as the influx rises up the well bore

c. To maintain a constant casing shoe pressure as the gas migrates through the open hole and casing annulus

d. To maintain the Bottom Hole Pressure (BHP) close to the formation pressure while the influx rises up the annulus.

10 WBM VS OBM

10.1 The following statement describe one of the difference between drilling with oil based mud And water based mud.

Hydrocarbon gas is more soluble in water based mud than in oil based mud.

a. Yes.

b. No

10.2 Why a hydrocarbon gas influx is harder to detect in oil based drilling fluid than in water based drilling fluid?

a. Hydrocarbon gas has a higher bubble point in oil based drilling fluid

b. Hydrocarbon gas has a lower bubble point in water based drilling fluid

c. Hydrocarbon gas is soluble in oil based drilling fluid

d. Hydrocarbon gas is soluble in water based drilling fluid

10.3 Why is a hydrocarbon gas influx easier to detect in water-based drilling fluid than oil-based drilling fluid?

a. Hydrocarbon gas has a higher bubble point in water-based

b. Hydrocarbon gas has a lower bubble point in water-based

c. Hydrocarbon gas is insoluble in water-based drilling fluid

d. Hydrocarbon gas is soluble in water-based drilling fluid

11 Hydrates

11.1 Which statement about hydrate removal is correct?

a. Increasing the pressure at the choke helps to remove hydrates

b. Injecting distilled water into the flow stream helps to remove hydrates

c. Injecting methanol into the flow stream helps to remove hydrates

d. Reducing the temperature below the freezing point helps to remove hydrates

11.2 While drilling with water based fluid, the well kicks and is shut in.

Which condition is most likely to lead to hydrate formation when the gas kick is circulated out at surface?

a. If the gas is circulated out at high temperature and high pressure.

b. If the gas is circulated out at low temperature and high pressure

c. If the gas is circulated out at high temperature and low pressure

d. If the gas is circulated out at low temperature and low pressure.

11.3 What fluid additives are commonly used to prevent or remove hydrates? *(Two answers)*

a. Carboxy Methyl Cellulose (CMC)

b. Diesel oil

c. Glycol

d. Methanol

e. Water

11.4 In which situation can hydrate form?

a. When there is a natural gas influx while using oil based fluid

b. When there is a natural gas influx while using water based fluid

c. When there is a water influx while using water based fluid

d. When there is an oil influx while using water based fluid

P & P Model Answers

1.1 b
1.2 b
1.3 c

2.1 b
2.2 a
2.3 c
2.4 d
2.5 d
2.6 b
2.7 a
2.8 d
2.9 a
2.10 a
2.11 a, d, e
2.12 a, d, e
2.13 a
2.14 d

3.1 d
3.2 a
3.3 d
3.4 d
3.5 c
3.6 c

4.1 a, b
4.2 d
4.3 b
4.4 b
4.5 a, c
4.6 b
4.7 d
4.8 d
4.9 b
4.10 d
4.11 c

5.1 c,d
5.2 c
5.3 c, e
5.4 a, b
5.5 a, c
5.6 b
5.7 b
5.8 b

6.1 a
6.2 a
6.3 d
6.4 b
6.5 a, e
6.6 a, b
6.7 d
6.8 a, d
6.9 a
6.10 a
6.11 d

7.1 c
7.2 d
7.3 a, f, g
7.4 a, e
7.5 a, c
7.6 b
7.7 d
7.8 c
7.9 d
7.10 c
7.11 b, e
7.12 d
7.13 b
7.14 d
7.15 c, e
7.16 b
7.17 d
7.18 a
7.19 d
7.20 d
7.21 a
7.22 c
7.23 c
7.24 a
7.25 d
7.26 c
7.27 a
7.28 d
7.29 c
7.30 b
7.31 c
7.32 a
7.33 c
7.34 d
7.35 b
7.36 d
7.37 d

7.38 a, b
7.39 b
7.40 d
7.41 b
7.42 d, e
7.43 b
7.44 a
7.45 b
7.46 c
7.47 a
7.48 c
7.49 b
7.50 b
7.51 c
7.52 d
7.53 b
7.54 c
7.55 a
7.56 d
7.57 c
7.58 a
7.59 c
7.60 d
7.61 d
7.62 c
7.63 e
7.64 c

8.1 c
8.2 a
8.3 d
8.4 b
8.5 b
8.6 b
8.7 c
8.8 c
8.9 d
8.10 d
8.11 b, c
8.12 d
8.13 d
8.14 a, c, f
8.15 b
8.16 c
8.17 c
8.18 b
8.19 a
8.20 d
8.21 b

9.1 a, b
9.2 c
9.3 b
9.4 c
9.5 b
9.6 b
9.7 b, c, d, e
9.8 c, d, e
9.9 c
9.10 b
9.11 c, e
9.12 c
9.13 a
9.14 a
9.15 a
9.16 a, b, d
9.17 c
9.18 c
9.19 a
9.20 c
9.21 d
9.22 b
9.23 d
9.24 d, e
9.25 b

9.26 a
9.27 c
9.28 a
9.29 b
9.30 c
9.31 a
9.32 a
9.33 d
9.34 a, b
9.35 c

9.36 b
9.37 c
9.38 a
9.39 d
9.40 d
9.41 b, e
9.42 c
9.43 b
9.44 a
9.45 c
9.46 c, e
9.47 b
9.48 b
9.49 b
9.50 a
9.51 c
9.52 d

9.53 a, c
9.54 d
9.55 c
9.56 b
9.57 a
9.58 b
9.59 c
9.60 b
9.61 b
9.62 c
9.63 c
9.64 d
9.65 a
9.66 a
9.67 a
9.68 a
9.69 d
9.70 d
9.71 c
9.72 d
9.73 d
9.74 a
9.75 b
9.76 a
9.77 b
9.78 b
9.79 c
9.80 d
9.81 b
9.82 c
9.83 c
9.84 c
9.85 d
9.86 b
9.87 b
9.88 d
9.89 a,c
9.90 c
9.91 c, d
9.92 a
9.93 b
9.94 b
9.95 b
9.96 d
10.1 b
10.2 c
10.3 c
11.1 c
11.2 b
11.3 c, d
11.4 b

Part 3: Well Control Problems

Version: Nov-19

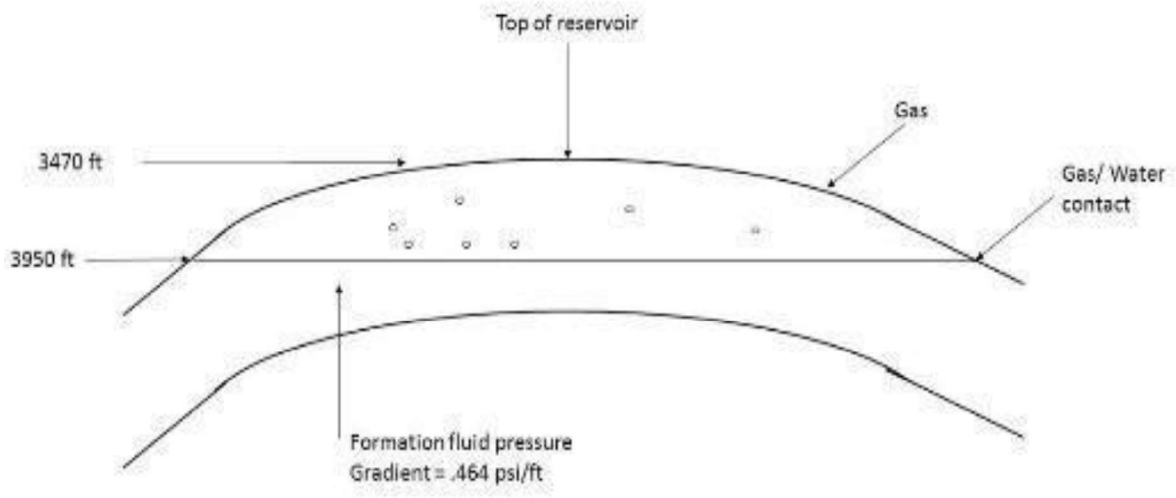
1. Static and Dynamic Pressures

Bottom-hole pressure Change

1.1 When drilling a 26 inch surface hole at 1200 feet True Vertical Depth (TVD), the formation pressure is measured as exactly 601 psi.
How would you describe this formation pressure?

a. Above normal
b. Below normal
c. Normal

1.2 If the gas/water contact in a normally pressured reservoir is at 3950 feet, what is the pressure at the top of the reservoir at 3470 feet? (There is a gas gradient 0.1 psi/ft, formation water gradient of 0.464 psi/ft.



a. 1350 psi
b. 1630 psi
c. 1785 psi
d. 1870 psi

1.3 There is a total power loss.
Partial losses are measured at 10 bbl/hour

Capacity of Annulus and Pipe contents – 0.073 bbl/ft
Drilling fluid density – 10.8 ppg

What will be the reduction in Bottom Hole Pressure (BHP) after 3 hours if the hole cannot be filled?

a. 231 psi
b. 300 psi
c. 420 psi
d. 77 psi

1.4 Calculate bottom hole pressure using the information below:

Well Measured Depth (MD)	**18575 feet**
Well True Vertical Depth (TVD)	**16281 feet**
Shoe True Vertical Depth (TVD)	**12875 feet**
Maximum Allowable drilling fluid density	**17.8 ppg**
Current drilling fluid density	**14.7 ppg**

a. 11917 psi
b. 12445 psi
c. 14199 psi
d. 9842 psi

1.5 A well is drilled to 9000 ft Measured Depth (MD) and the True Vertical Depth (TVD), with 10 ppg of drilling fluid.
If the drilling fluid is then displaced to 11 ppg fluid, how would this affect the hydrostatic pressure at the bottom of the hole?

a. Hydrostatic pressure would decrease
b. Hydrostatic pressure would increase
c. Hydrostatic pressure would stay the same

1.6 Pressure recorders located below the drill stem test tools show that the swab pressure is 250.

Drilling fluid density in the hole is 10 ppg. .

Top of reservoir is at 9500 feet.

If the well does not flow when the pipe is static, what would the reservoir pressure have to be at this swab pressure?

a. 3800 psi.
b. 5800 psi.
c. 4690 psi.
d. 4940 psi.

1.7 A well is of TVD 5000 FT and MWT 9.8 PPG.

The cutting inside the annulus increased the mud weight by 0.2 PPG.

What is the final BHP if the pumps were stopped?

…………………… psi

1.8 Formation pressure at 9200 feet True Vertical Depth (TVD) is balanced by 10.6 ppg mud. A 250 psi trip margin must be included in the drilling fluid density.

What drilling fluid density would be required?

a. 10.1 ppg
b. 10.6 ppg
c. 11.2 ppg
d. 11.7 ppg

1.9 Formation pressure at 8350 feet True Vertical Depth (TVD) is anticipated to be 4430 psi.

A 250-psi trip margin must be included in the drilling fluid density.

What drilling fluid density would be required?

a. 10.2 ppg
b. 12 ppg
c. 9.6 ppg
d. 10.8 ppg

1.10 When drilling at 17750 feet Measure Depth (MD), 14650 feet True Vertical Depth (TVD), formation pressure is balanced by 12.3 ppg drilling fluid.
A 350-psi trip margin must be included in the drilling fluid density.
What drilling fluid density is required?

…………………… ppg

1.11 Before pulling out of hole, the drilling fluid density is increased by 0.5 ppg trip margin.
With this trip margin, calculate the increase in Bottom Hole Pressure (BHP).
Well Data:

Well depth (TVD): 8300 ft
Well depth (MD): 8900 ft

Drilling fluid density without trip margin: 11.2 ppg
Drill pipe capacity: 0.01782 bbl/ft

Drill pipe metal displacement: 0.00751 bbl/ft

……………………………………..psi

1.12 Formation pressure at 9200 feet True Vertical Depth (TVD) is balanced by 10.6 ppg mud weight and 287 psi trip margin must be included in the drilling fluid density. What drilling fluid density is required?

a. 10.1 ppg
b. 10.6 ppg
c. 11.2 ppg
d. 11.7 ppg

1.13 The driller fails to fill the hole when pulling out of the well.
The drilling fluid level drops 580 feet causing the well to flow.

Current drilling fluid density: 11.9 ppg.
True Vertical Depth (TVD): 9500 feet

What is the Bottom Hole Pressure (BHP) when the well starts to flow?

……………………………………..psi

1.14 While drilling, there are severe losses. After the pumps are stopped, the drilling fluid level drops far below the flowline. The well is then filled to the top with water.

Drilling fluid density: 11.3 ppg

Water density: 8.6 ppg

Volume of water filled into the annulus is 200 feet.

What is the decrease in hydrostatic Bottom Hole Pressure (BHP)?

a. 118 psi
b. 207 psi
c. 28 psi
d. 89 psi

1.15 Calculate the fluid density if the fluid gradient is 0.884 psi/ft

…………………… ppg

1.16 What is the reduction in Bottom Hole Pressure (BHP) if the drilling fluid level dropped by 800 feet with a density of 10.5 ppg?

…………………… psi

1.17 How much will the Bottom Hole Pressure (BHP) decrease if the annular fluid drops by 100 feet? The Drilling fluid density is 15 ppg.

……………………**psi**

1.18 Calculate bottom hole hydrostatic pressure using the information below:

Well Measured Depth (MD):	**18575 feet**
Well True Vertical Depth (TVD):	**16281 feet**
Shoe True Vertical Depth (TVD):	**12875 feet**
Maximum allowable drilling fluid density:	**17.8 ppg**
Current drilling fluid density:	**14.7 ppg**

a. 11917 psi
b. 12445 psi
c. 14199 psi
d. 9842 psi

1.19 On a trip out of hole, the hole was filled correctly while pulling drill pipe. The hole fill was stopped and the complete BHA was pulled dry

Hole size:	**12 ¼ inch**
Casing shoe depth:	**1500 feet**
Length of BHA:	**400 feet**
Internal capacity of BHA:	**0.009 bbl/ft**
Internal capacity of casing:	**0.146 bbl/ft**
Steel displacement of BHA:	**0.070 bbl/ft**
Capacity between BHA and Casing:	**0.067 bbl/ft**
Drilling fluid density:	**10 ppg**

What is the expected decrease in Bottom Hole Pressure (BHA)?

a. 100 psi
b. 188 psi
c. 205 psi
d. 210 psi

Dynamic Pressure

1.20 A vertical well is 6020 feet deep and filled with 11.5 ppg mud.

While circulating at 80 SPM the friction losses in the well system are as follows:

a. 200 psi pressure loss through surface equipment.

b. 680 psi pressure loss in drill string.

c. 1570 psi pressure loss through bit nozzles.

d. 110 psi pressure loss in annulus.

What is the Bottom Hole Pressure (BHP) when the pumps are running at 80 SPM?

……………………psi

1.21 At 40 spm with 10 ppg fluid, the pump pressure is 1000 psi.

What is the pump pressure if the rate is decreased to 25 spm and the fluid density is increased to 11.4 ppg?

a. 390 psi

b. 445 psi

c. 550 psi

d. 710 psi

2. <u>Leak-Off Test</u>

2.1 Calculate the MAASP using the following information:

Well Data:

Casing Shoe depth (TVD): 6800 feet

Maximum Allowable drilling fluid density: 16.7 ppg

Density of drilling fluid in hole: 15 ppg

…………………… psi

2.2 Calculate the formation strength at the casing shoe using the following information?

Well Data:

Casing Shoe Depth (TVD)	**6000 ft**
Drilling Mud Density	**12 ppg**
MAASP	**1300 psi**

……………………psi

2.3 Calculate the maximum allowable mud weight using the following

Well Data:

Casing shoe depth:	**8000 ft, TVD**
Leak off test pressure at pump:	**1500 psi**
Density of drilling mud in hole:	**10.4 ppg**

……………………ppg

2.4 After conditioning the well with 12 ppg mud, the Driller does a Leak-Off Test (LOT) at 5000 feet True Vertical Depth (TVD), and records a LOT pressure of 875 psi.

Calculate the maximum allowable mud density.

a. 17.1 ppg
b. 13.2 ppg
c. 14.5 ppg
d. 15.3 ppg

2.5 Given that the Formation strength is 1900 psi, the Casing shoe TVD is 2000 ft, the Annulus Pressure Losses (APL) is 250 psi;

Calculate the maximum mud density that can be used/circulated, without causing mud losses.

……………………ppg

2.6 Calculate the MAASP with the following information:

Well Data:

Hole depth (MD):	**11500 feet**
Hole depth (TVD):	**10200 feet**
Casing shoe depth (MD):	**8200 feet**
Casing shoe depth (TVD):	**7400 feet**
Drilling fluid density:	**10 ppg**
Formation strength gradient:	**0.707 psi/ft**

……………………psi

2.7 Well Data:

13-3/8 inch casing is set at 4921 feet True Vertical Depth (TVD)

Formation strength at the shoe: 3626 psi. (Determined by a leak-off test)

Current fluid density: 10 ppg.

What is the Maximum Allowable Annulus Surface Pressure (MAASP)?

a. 1067 psi
b. 1807 psi
c. 3045 psi
d. 425 psi

2.8 After a leak-off test using 10.3 ppg test fluid, casing shoe fracture pressure is calculated at 5730 psi.

Maximum anticipated Annular Pressure Loss (APL) at drilling rate for the section is 350 psi

Casing Shoe True Vertical Depth (TVD) is 8640 feet

What is the maximum drilling fluid density that can be circulated without losses?

…………………… ppg

2.9 The deepest casing shoe in a well is set at 5675 feet MD, 5125 feet TVD. If the mud density is increase by 1.2 ppg, how will this affect MAASP?

a. It will be 320 psi higher.
b. It will be 320 psi lower.
c. It will be 354 psi higher.
d. It will be 354 psi lower.

2.10 Leak-off Test Data:

CSG. Shoe MD:	**6090 ft.**
CSG. Shoe TVD:	**5560 ft.**
Surface Leak off pressure at 6090 ft.:	**380 psi**
Drilling fluid density:	**12.8 ppg**

Drilling continues after the leak off test, and later there is a kick.

Kick Data:

Hole depth MD:	**7810 ft**
Hole depth TVD:	**6315 ft**
SIDPP:	**140 psi**
SICP:	**180 psi**
Pit gain:	**8 bbl.**
Drilling fluid density:	**13.5 ppg**

Calculate the working margin between the MAASP and the initial shut in casing pressure.

a. 18 psi
b. 47 psi
c. 87 psi
d. No margin

3. Tripping

3.1 What is the bottom hole hydrostatic pressure reduction when pulling 1000 ft. of 5" drill pipe dry without filling the hole (no mud returning to the well)?

Well Data:

Casing capacity: **0.1522 bbl./ft.**

Drill pipe capacity: **0.0178 bbl./ft. Drill pipe steel displacement:** **0.0076 bbl./ft.**

Mud density: **11 ppg**

a. 51 psi
b. 61 psi
c. 30 psi
d. 101 psi

3.2 Well Data:

Current drilling fluid density:	10 ppg
Metal displacement:	**0.0075 bbl./ft.**
Pipe Capacity:	**0.0178 bbl./ft.**
Casing Capacity:	**0.0758 bbl./ft.**
Stand length:	**93 ft.**

What is the drop in hydrostatic pressure if 10 stands of pipe are pulled 'dry' from the well?

…………………… psi

3.3 Well Data:

Current fluid density:	**10 ppg**
Metal displacement:	**0.0075 bbl./ft.**
Pipe capacity:	**0.0178 bbl./ft.**
Casing capacity:	**0.0758 bbl./ft.**
Stand length:	**93 ft.**

What is the drop in hydrostatic pressure if 10 stands of pipe are pulled 'wet' from the well?

……………………psi

3.4 Well Data:

TVD:	**5643 ft.**
MD:	**5900 ft.**
Formation Pressure:	**2770 psi.**
Current fluid density:	**10.4 ppg**
Metal displacement:	**0.0075 bbl./ft.**
Pipe capacity:	**0.0178 bbl./ft.**
Casing capacity:	**0.0758 bbl./ft.**
Stand length:	**90 ft.**

How many dry stands the Driller to pull out of hole without going underbalance?

a. 11 stands
b. 12 stands
c. 52 stands
d. 53 stands

3.5 Given the following data:

Hole TVD: 8680 ft.

5'' Drill Pipe Capacity: 0.0778 bbl/ft.

6.5'' Drill collar Capacity: 0.0077 bbl/ft. BHA length: 774 FT

Surface line Capacity 12 BBLs

Mud Pump Displacement 0.12 BBL/stroke. Pump Speed (rate) 30SPM

A kick was taken after pulling 930 ft. of 5'' drill pipe off bottom.

How long would it take to circulate the Heavy Mud From the active pumps to the bit?

……………………minutes

3.6 Given the following data:

Hole TVD: 8680 ft.

5'' Drill Pipe Capacity: 0.0778 bbl/ft.

6.5'' Drill collar Capacity: 0.0077 bbl/ft. BHA length: 774 FT

Surface line Capacity 12 BBLs

Mud Pump Displacement 3.6 bbl/min.

Pump Speed (rate) 30 SPM

A kick was taken after pulling 930 ft. of 5'' drill pipe off bottom.

How long would it take to circulate the Heavy Mud From the active pumps to the bit?

……………………minutes

3.7 A well is shut in with bit 10 stands 930 ft. off bottom. What is the bit to shoe strokes if a pump capacity of 0.12 bbl./stroke is used to circulate the well?
Well Data:

Well depth:	**9750 ft. MD (8560 ft. TVD)**
Casing	**8076 ft. MD (7076 ft. TVD)**
Bottom Hole Assembly (BHA) length:	**744 ft.**
Open Hole (OH) / BHA Capacity:	**0.102 bbl./ft.**
OH/Drill pipe (DP) Capacity:	**0.132 bbl./ft.**

a. 471 strokes
b. 609 strokes
c. 632 strokes

3.8 A well is shut in with bit 10 stands 930 ft. off bottom. What is the pump to bit strokes if the pump capacity of 0.12 bbl./stroke is used to circulate the well?
Well data:

Well depth:	**9750 ft. MD (8560 ft. TVD)**
Bottom Hole Assembly (BHA) length:	**744 ft.**
Capacity of HP surface line:	**12 bbl.**
BHA Capacity:	**0.0078 bbl./ft.**
Drill pipe (DP) Capacity:	**0.0178 bbl./ft.**

a. 1159 strokes
b. 1246 strokes
c. 1346 strokes

3.9 The Driller pulls three stands of drill collars from a well (dry).

Drill collar capacity:	**0.0073 bbl/ft**
Drill collar metal displacement:	**0.0370 bbl/ft**

How many barrels of drilling fluid should the Driller pump into the well? (One stand = 90')

……………………bbl.

3.10 Calculate the volume of drilling fluid required to fill the hole per stand when pulling 'wet', with no drilling fluid returns to the well.

Well Data:

Drill Pipe Capacity:	**0.0178 bbl./ft.**
Drill Pipe Metal Displacement:	**0.0082 bbl./ft.**
Average Stand Length:	**93 ft.**

a. 0.76 bbl.
b. 1.65 bbl.
c. 2.42 bbl.
d. 9.28 bbl.

4. Slug

4.1 A driller prepare to pull out of the hole and line up to the slug pit. The driller then pumps a 20 bbl heavy slug, followed by 10 bbl of drilling fluid from the active pit.

Well Data:

Depth of hole (TVD):	**9200 ft.**
Drilling fluid density:	**12.2 ppg.**
Heavy slug density:	**14.5 ppg**
Drill pipe capacity:	**0.01776 bbl./ft.**
Surface line volume:	**6 bbl.**

How far will the fluid level in the string drop when the well has equalized?

a. 1143 feet
b. 183 feet
c. 213 feet
d. 263 feet

4.2 The Driller pumps a 25 bbl. Heavy slug with a density of 12 ppg before pulling out of the hole from 10500 ft. True Vertical Depth (TVD). The level in the pipe decreases falls by 215 ft.

What is the change in Bottom Hole Pressure (BHP) if the original drilling fluid density was 10.4 ppg?

a. 0 psi
b. 1180 psi
c. 140 psi
d. 20 psi

5. Volumetric Method/Stripping

5.1 A vertical well is shut in after there is a gas influx. The kill operation is delayed, and the influx starts to migrate.

Because of this migration, both drill pipe pressure and casing pressure increase by 300 psi

Well Data:

Well depth:	**10000 ft.**
Casing shoe depth:	**6000 ft.**
Drilling fluid density:	**11.7 ppg**
Open hole/drill pipe capacity:	**0.060 bbl./ft.**
Casing/drill pipe capacity:	**0.065 bbl./ft.**

NOTE: Assume there is only drill pipe in the well.

Kick Data:

Original shut in stabilized drill pipe pressure:	**800 psi**
Original shut in stabilized casing pressure:	**1050 psi**
Original kick volume:	**30 bbl.**

How many barrels of drilling fluid should be bled from the well to arrive at the original bottom hole pressure, before gas migration?

a. 1.31 bbl.
b. 1.32 bbl.
c. 1.36 bbl.
d. 2.16 bbl.

5.2 A well is shut in after a kick has been taken.

SIDPP 600 psi

SICP 1000 psi

After 15 minutes the pressure has risen 100 psi on both gauges. The mud density is 15 ppg and the influx gradient is 0.1 psi/ft.

Approximately how many feet per hour is the gas bubble migrating?

a. 129 ft./hr.
b. 1400 ft./hr.
c. 200 ft./hour
d. 513 ft./hour

5.3 A vertical well with a surface BOP stack has been shut in after a gas kick. The surface pressures are as follows:

Shut in Drill Pipe Pressure (SIDPP)	**530 psi**
Shut in Casing Pressure (SICP)	**680 psi**
Mud density in the well	**12.8 ppg**

The well is left shut in for some time, during which the gas migrates 600 feet up the well.

What will be the expected pressures at surface?

a. Drill pipe pressure – 530 psi, casing pressure – 1080 psi
b. Drill pipe pressure – 530 psi, casing pressure – 680 psi
c. Drill pipe pressure – 930 psi, casing pressure – 1080 psi
d. Drill pipe pressure – 930 psi, casing pressure – 680 psi

6. Various

6.1 Whilst drilling a horizontal well a fault is crossed and a kick is taken. The well is shut in. Calculate the mud density required to kill the well using the data below:

Well Data:

Depth at start of horizontal section:	**MD 6500 ft.**	**TVD 4050**
Depth at time of kick:	**MD 10500**	**TVD 3970**
Length of horizontal section:	**4000 ft.**	
Mud density:	**11.2 ppg**	

Kick Data:

Shut In Drill Pipe Pressure:	**150 psi**
Shut In Casing Pressure:	**150 psi**

……………………ppg

6.2 While drilling through a fault in the horizontal section of a well, a kick is taken and the well shut in.

Calculate the new mud density required to kill the well using the data below.

Well Data:

Measured depth at start of horizontal section:	**7690 ft.**
Measured depth at time of kick:	**13680 ft.**
True vertical depth at start of horizontal:	**5790 ft.**
True vertical depth at time of kick:	**5820 ft.**
Length of horizontal section:	**5990 ft.**
Mud density:	**12.8 ppg**

Kick Data:

Shut In Drill Pipe Pressure	**230 psi**
Shut In Casing Pressure	**240 psi**

a. 13.1 ppg
b. 13.4 ppg
c. 13.6 ppg
d. 13.7 ppg

6.3 A vertical well with a surface BOP stack is shut in after a gas kick.

The bit is 500 feet off bottom and the influx is calculated to be on bottom Shut in Drill Pipe Pressure (SIDPP) is 250 psi.

What will the Shut In Casing Pressure (SICP) be?

a. Zero
b. 250 psi
c. 750 psi

6.4 A well is shut in after a kick and will be killed using the Wait and Weight Method.

Pre-recorded data:

True Vertical Depth (TVD) of well:	**10000 ft.**
Total string volume:	**1400 strokes**
Total annulus volume:	**5700 strokes**

Kill rate circulating data:

At 30 SPM is 520 psi

Kick data:

Shut-In Drill Pipe Pressure (SIDPP):	**480 psi**
Shut In Casing Pressure (SICP):	**650 psi**
Drilling fluid density in the well:	**12.0 ppg**

What is the Final Circulating Pressure (FCP) at 30 SPM?

a. 564 psi
b. 607 psi
c. 720 psi
d. 752 psi

6.5 A well is shut in after a kick and will be killed using the Wait and Weight Method.

Pre-recorded data:

True Vertical Depth (TVD) of well:	**10000 ft.**
Total string volume:	**1400 strokes**
Total annulus volume:	**5700 strokes**

Kill rate circulating data:

At 30 SPM and 12.0 ppg mud weight:	**520 psi**

Kick data:

Shut In Drill Pipe Pressure (SIDPP):	**480 psi**
Shut In Casing Pressure (SICP):	**650 psi**
Drilling fluid density in the well:	**12.0 ppg**

What is the required kill fluid density?

a. 12.8 ppg
b. 13.0 ppg
c. 13.2 ppg
d. 13.3 ppg

6.6 The well is shut in after a kick, and will be killed using the Wait and Weight Method.

Kill rate circulating date:

At 30 SPM is 520 psi

Shut-in data:

Shut In Drill Pipe Pressure (SIDPP):	**480 psi**
Shut In Casing Pressure (SICP):	**650 psi**
Drilling fluid density in the well:	**12.0 ppg**

Calculate the Initial Circulating Pressure (ICP) at 30 SPM.

a. 1000 psi
b. 1070 psi
c. 1130 psi
d. 1170 psi

6.7 While drilling through a fault in the horizontal section of a well, a kick is taken and the well is shut in. calculate the new mud density required to kill the well using the data below:

WELL DATA

Measured depth at start of horizontal section:	**7690 ft.**
Measured depth at time of kick:	**13680 ft.**
True vertical depth at start of horizontal:	**5790 ft.**
True vertical depth at time of kick:	**5820 ft.**
Length of horizontal section:	**5990 ft.**
Mud density:	**12.8 ppg**

KICK DATA

Shut in Drill pipe pressure:	**230 psi**
Shut in Casing pressure:	**240 psi**

a. 13.1 ppg
b. 13.4 ppg
c. 13.6 ppg
d. 13.7 ppg

Model Answers

1.1 A

Formation Pressure Gradient = Pressure / Depth

= 601 / 1200

= **0.5 psi/ft. > 0.465 psi/ft.**

1.2 C

Pressure at the top of the reservoir = Pressure at the gas/water contact – Gas hydrostatic

= (3950 x 0.464) – {(3950-3470) x 0.1}

= 1832.8 – (480 x 0.1)

= 1832.8 – 48

= **1784.8 psi**

1.3 Reduction in Hydrostatic pressure = Level Drop x Mw x 0.052

= (10 bbl./hr. x 3 hours / 0.073) x 10.8 x 0.052

= 410.958 x 10.8 x 0.052

= **230.79 psi**

1.4 Bottom Hole Pressure = Mw x Well TVD x 0.052

= 14.7 x 16281 x 0.052

= **12445 psi**

1.5 B

1.6 Expected Reservoir Pressure = Hydrostatic Pressure – Swab Pressure

= (9500 x .052 x 10) - 250

= 4940 - 250

= **4690 psi**

1.7 Final Bottom-hole pressure = (Mud density + cuttings density) x .052 x TVD

= (9.8 + 0.2) x .052 x 5000

= 10 x .052 x 5000

= **2600 psi**

1.8 Mud density with trip margin included = Equation Number 8

= (250 / 9200 / .052) + 10.6

= **11.12 ppg**

1.9 D

Drilling Fluid Density with Trip margin = (Formation pressure + Trip Margin) / (0.052 x TVD)

= (4430 + 250) / (8350 x 0.052)

= 4680 / 434.2

= **10.77 psi**

1.10 Drilling Fluid density with trip margin = Current Mw + [Trip Margin / (TVD x 0.052)]

= 12.3 + ({350 / (14650 x 0.052)}

= 12.3 + (350 / 761.8)

= **12.75 – 12.8 ppg**

1.11 Increase in BHP = Increase in Trip Margin x .052 x TVD

= 0.5 x .052 x 8300

= **215- 216 psi**

1.12 Mud density with trip margin included = Equation Number 8

= (287 / 9200 / .052) + 10.6

= **11.19 ppg**

1.13 Bottom-hole pressure = New drilling fluid level x .052 x Mud density

= (9500 – 580) x .052 x 11.9

= 8920 x .052 x 11.9

= **5519.69 – 5520 psi**

1.14 Decrease in hydrostatic pressure = (Mud density – Water density) x water height x 0.052

= (11.3 - 8.6) x 200 x 0.052

= **28 psi**

1.15 Mud density = Mud gradient / .052

= .884 / .052

= **17 ppg**

1.16 Reduction in BHP = Reduction in Hydrostatic pressure

= Reduction in drilling fluid level x .052 x Mud density

= 800 x .052 x 10.5

= **436.8 – 437 psi**

1.17 BHP drop = Level drop x Mw x 0.052

= 100 x 15 x 0.052

= **78 psi**

1.18 Hydrostatic Pressure = Well TVD x .052 x Mud density

= 16,281 x .052 x 14.7

= 12,445.19 psi

1.19 A

Level drop = Length of BHA × Metal Displacement ÷ Casing capacity (Eq. 21)

= 400 × 0.070 ÷ 0.146

= 191.78 ft.

BHP drop = Level drop x Mwt. x 0.052

= 191.78 x 10 x 0.052

= 99.72 ≈ 100 psi.

1.20 BHP while circulating = Hydrostatic Pressure + APL

= (6020 x 0.052 x 11.5) + 110

= **3709.96 - 3710 psi**

1.21 Equations 9 and 10

New Pump pressure = Old pump pressure x (New Mw / Old Mw) x (New SPM / Old Spm)^2

= 1000 x (11.4 / 10) x (25 /40)^2

= **445 psi**

2.1 MAASP = (Maximum Mud Weight – Current Mud Weight) x Shoe TVD x 0.052

= (16.7 – 15) x 6800 x 0.052

= **601 – 601.12 psi**

2.2 Formation Strength = MAASP + Hydrostatic Pressure above casing shoe

= 1300 + (6000 x .052 x 12)

= 1300 + 3744

= **5044 psi**

2.3 Maximum Allowable Mud density = Equation Number 11

= (1500 / 8000 / .052) + 10.4

= **14 ppg**

2.4 D

Maximum Mud density = Test Mud Weight + [LOT pressure / (Shoe TVD x 0.052)]

= 12 + {875 / (5000 x 0.052)}

= 12 + (875 / 260)

= **15.36 ppg**

2.5 Maximum Allowable Mud density with APL = (Formation Strength – APL) / (TVD x .052)

= (1900 – 250) / (2000 x .052)

= 1650 / 104

= **15.8 – 15.86 ppg**

2.6 MAASP = Equation Number 12

= (Maximum Allowable Mud density – Current Mud density) x .052 x Shoe TVD

*Maximum Allowable Mud density = Formation Strength Gradient / .052

= .707 / .052

= 13.5 – 13.59

*MAASP = (13.5 - 10) x .052 x 7400

= 3.5 x .052 x 7400

= 1346 – 1346.8 psi

*MAASP = (13.59 -10) x .052 x 7400

= 3.59 x .052 x 7400

= 1381 – 1381.4 psi

MAASP = Formation Strength - Hydrostatic Pressure above casing shoe

= (Formation Strength gradient x Shoe TVD) - Hydrostatic Pressure above casing shoe

= (.707 x 7400) - (7400 x .052 x 10)

= 5231.8 - 3848

= **1383 – 1383.8 psi**

2.7 MAASP = Formation Strength – Hydrostatic Pressure above casing shoe

= 3626 - (4921 x .052 x 10)

= 3626 - 2558.92

= 1067 – 1067.08 psi

2.8 Fracture Pressure including safety margin = Fracture pressure at test – APL

= 5730 – 350

= 5380 psi

Maximum fluid density for circulation = Fracture pressure with safety / (Shoe TVD x 0.052)

= 5380 / (8640 x 0.052)

= **11.9 - 11.97 ppg**

2.9 B

MAASP change = Hydrostatic Pressure change above casing shoe

= Mud weight change above casing shoe x .052 x TVD

= +1.2 x .052 x 5125

= **+319.8 psi**

The hydrostatic increased, then the MAASP should decrease by **319.8 – 320 psi**

2.10 D

Maximum Mud weight = Mud weight at test + [LOT pressure / (Shoe TVD x 0.052)]

= 12.8 + {380 / (5560 x 0.052)

= 14.11 ppg

MAASP with mud weight 13.5 ppg = (Maximum Mw – Current Mw) x Shoe TVD x 0.052

= (14.11 – 13.5) x 5560 x 0.052

= 177 psi

Safety Margin = MAASP – SICP

= 177 – 180 = **-3 psi (No margin)**

3.1 Pressure drop after pulling dry pipe = Equation Number 19 x Length of pipe

= (11 x .052 x .0076) / (.1522 - .0076)   x 1000

= (.0043472   / .1446)   x 1000

= 30 – 30.06 psi

3.2 Pressure drop after pulling dry pipe = Equation Number 19 x Length of pipe

= (10 x 0.052 x 0.0075) / (0.0758 – 0.0075) x (10 x 93)

= (0.0039   / 0.0683)   x 930

= **53 - 53.1 psi**

3.3 Formula #20:

Pressure Drop = (Mw x 0.052 x Closed End) / (Casing Capacity – Closed End)

Closed End = Metal displacement + Internal capacity

= 0.0075 + 0.0178

= 0.0253 bbl./ft.

Pressure Drop = (10 x 0.052 x 0.0253) / (0.0758 – 0.0253)

= 0.013156 / 0.0505

= 0.26 psi/ft.

Total pressure drop = 0.26 x 10 stands x 93 feet = **241.8 – 242 psi**

3.4 C

Formula #23

Lg. dry tubulars = Overbalance x [CSG Cap. – Metal Displ.] / 0.052 x Mw x Metal Displ.

Overbalance = Hydrostatic pressure – Formation pressure

= 0.052 x Mw x TVD – 2770

= 0.052 x 10.4 x 5643 – 2770

= 3051.7 – 2770

= 281 psi

Length of tubulars = 281 x [0.0758 – 0.0075] / 0.052 x 10.4 x 0.0075

= 4731.8 ft.

Number of stands = Length of tubulars / stand length

= 4731.8 / 90

= 52.58 stands

Round down so as not to go underbalance:

Number of stands = 52 stands.

3.5 Time to circulate from pumps to bit = Strokes pumped from pumps to bit / Pump Speed

*Strokes Pumped = Volume pumped / Pump Output

*Volume Pumped = Capacity of surface line + Capacity of drill string

= 12 + Drill Pipe capacity + BHA capacity

= 12 + ((Hole MD – Length pulled- BHA length) x .0778) + (.0077*774)

= 12 + ((8680 - 930 - 774) x .0778) + 5.9598

= 12 + (6976 x .0778) + 5.9598

= 12 + 542.7328 + 5.9598

= 560.6926 bbls

*Strokes Pumped = 560.6926 / .12

= 4672-4673 strokes

*Time = 4673 / 30

= **155.7 – 156 minutes**

3.6 Time to circulate from pumps to bit = Strokes pumped from pumps to bit / Pump Speed

*Strokes Pumped = Volume pumped / Pump Output

*Volume Pumped = Capacity of surface line + Capacity of drill string

= 12 + Drill Pipe capacity + BHA capacity

= 12 + ((Hole MD – Length pulled- BHA length) x .0778) + (.0077*774)

= 12 + ((8680 - 930 - 774) x .0778) + 5.9598

= 12 + (6976 x .0778) + 5.9598

= 12 + 542.7328 + 5.9598

= 560.6926 bbls

*Time = 560.6926 / 3.6

= **155.7 – 156 minutes**

3.7 Bit To shoe strokes = Open hole volume / pump output

= (BHA length x BHA/OH capacity + drill pipe length x OH/DP capacity) / POP

= (744 x 0.102 + (9750 – 8076 – 930 – 744) x 0.132) / POP

= (75.888 + 0) / 0.12

= **632 strokes**

3.8 C

Pump to bit strokes = Surface line strokes + drill pipe strokes + BHA strokes

Drill pipe strokes = (Drill pipe length x drill pipe capacity) / pump output

= ((9750 – 744 – 930) x 0.0178) / 0.12

= (8076 x 0.0178) / 0.12

= 143.752 / 0.12

= 1197 strokes

BHA strokes = (BHA length x BHA capacity) / Pump Output

= (744 x 0.0078) / 0.12

= 48 strokes

Surface line strokes = Surface line volume / Pump Output

= 12 / 0.12

= 100 strokes

Pump to bit strokes = 1197 + 48 + 100

= 1345 strokes

3.9 Volume of mud (dry) = Drill Collar Metal Displacement x Drill Collar Pulled Length

= 0.0370 x (3 x 90)

= 9.99 bbl.

3.10 Volume to fill the hole 'wet' = Stand length x Closed End displacement

= 93 x (0.0178 + 0.0082)

= **2.418 – 2.42 bbl.**

4.1 Level Drop due to slug = Pit Gain / Drill Pipe Capacity

*Pit Gain due to slug = Equation Number 27

= 20 x (1.1885 -1)

= 3.77 bbl.

*Level Drop due to slug = 3.77 / .01776

= **212.3 ft.**

4.2 A

5.1 Volume to bleed after gas migration = Equation Number 25

= (300 x 30) / (Formation Pressure – 300)

*Formation Pressure = Equation Number 4

= (10,000 x .052 x 11.7) + 800

= 6084 + 800

= 6884 psi

Volume to bleed = (300 x 30) / (6884 – 300)

= 9000 / 6584

= 1.36 - 1.366 – 1.367 bbl.

5.2 D

Formula #17

Gas Migration Rate = Rate of increase in pressure per hour / (Mw x 0.052)

= (100 x (60/15)) / (15 x 0.052)

= (100 x 4) / (15x 0.052)

= 512.82 ft./hr.

5.3 Pressure Increase due to gas migration = Migration Distance x .052 x Mud density

= 600 x .052 x 12.8

= 399.36 – 400 psi

***SIDPP = 530 + 400**

= 930 psi

***SICP = 680 + 400**

= 1080 psi

6.1 Kill Mud Density = Equation Number 13

= (SIDPP / **TVD at time of kick** / .052) + Original Mud density

= (150 / 3970 / .052) + 11.2

= 11.92 – 12 ppg

6.2 Kill Mud Density = Equation Number 13

= (SIDPP / **TVD at time of kick** / .052) + Original Mud density

= (230 / 5820 / .052) + 12.8

= 13.55 – 13.6 ppg

6.3 Off Bottom SIDPP = Off Bottom SICP

= 250 psi

6.4 A

Final Circulating Pressure = (Kill Mw / Current Mw) x RRCP

Kill Mud Density = Current Mw + {SIDPP / (TVD x 0.052)}

= 12 + {480 / (10000 x 0.052)}

= 12 + 0.92

= 12.92 - 13 ppg

FCP = (13 / 12) x 520

= **563.3 – 564 psi**

6.5 B

Kill Mw = Current Mw + {SIDPP / (TVD x 0.052)}

= 12 + {480 / (10000 x 0.052)}

= 12.93 – 13 ppg

6.6 A

Initial Circulating Pressure = SIDPP + RRCP

= **480 + 520 = 1000 psi**

Part 4: Kill Sheets

Kill Sheet #1

Well Data

Hole Size	12 1/4 inch
Hole Depth	9800 feet TVD/MD
Drill pipe	5 inch Capacity = 0.017766 bb/ft
Drill Collars	8 1/2 Inch, 680 feet long , capacity = 0.007 bbl/ft
Casing	13 3/8 casing set at 6500 feet TVD/MD
Mud density	10.8 ppg

Capacities

Drill collars in open hole	0.0756 bbls/ft
Drill pipe in open hole	0.1215 bbl/ft
Drill pipe in casing	0.1279 bbl/ft
Mud Pumps displacement	0.15 bbl/Stroke
Slow Circulating Rate	950 psi at 40 spm

A leak-off test was carried out at the $13^3/_8$ casing she and fracture Gradient at shoe is 0.806 psi/foot

The well was been shut in the following a kick

Kick Data

Shut-in Drill Pipe Pressure	800 psi
Shut-in Casing pressure	1000 psi
Pit Gain	30 bbl

Answer the following question from the data above

1. What is the kill mud density? = …... ppg
2. How many strokes are required to pump kill mud from surface to bit? = …… stroke
3. How many strokes are required to pump from bit to casing shoe? = …stroke
4. How many strokes are required to pump from bit to surface? = …… stroke
5. What is the MAASP at the time the well was shut in? = …... Psi
6. What is the MAASP after circulation of the kill mud? = …… psi
7. How many strokes are required for one complete circulation? =…... Stroke
8. What is the Initial Circulating pressure? = …… psi
9. What is the Final circulating pressure? = …… psi
10. What is the drill pipe pressure reduction per 100 strokes as kill mud is being pumped to the bit? = …… psi/ 100stk

Kill Sheet #2

Well Data

Hole Size	8 1/4 inch
Hole depth	11200 feet TVD, 12250 feet MD
Casing	9 5/8 casing set at 7500 TVD/MD
Drill pipe	5 inch, Capacity = 0.01776 bbl/ ft
Drill Collars	6 inch, 800 feet long, Capacity = 0.005 bbl/ft.
Mud density	12.2 ppg

Capacities

Drill collars in open hole	0.031 bbl/ft
Drill pipe in open hole	0.0418 bbl/ft
Drill pipe in casing	0.0529 bbl/ft
Mud Pumps displacement	0.2 bbl/Stroke
Slow Circulating Rate	1100 psi at 35 spm
Fracture Mud density at the casing shoe	16 ppg

The well was been shut in the following a kick

Kick Data

Shut-in Drill Pipe Pressure	750 psi
Shut-in Casing pressure	1000 psi
Pit Gain	20 bbl

Answer the following question from the data above

1. What is the kill mud density?	= …... ppg
2. What is the MAASP at the time the well was shut in?	= …… psi
3. How many strokes are required to pump kill mud from surface to bit?	= …... stroke
4. How many strokes are required to kill mud from bit to surface?	= …… stroke
5. How many strokes are required to pump from bit to casing shoe?	= …… Stroke
6. What is the time for one complete circulation?	= …... Minute
7. How many strokes are required for one complete circulation?	=…... Stroke
8. What is the initial circulating pressure?	= …… psi
9. What is the final circulating pressure?	= …… psi
10. What is the drill pipe pressure reduction per 100 strokes as kill mud is being pumped to the bit?	= …… psi/100stk

Kill Sheet #3

Well Data

Hole Size	12 1/4 inch
Hole depth	10200 feet TVD, 12220 feet MD
Casing	13 3/8 casing set at 6500 TVD, 8620 feet MD
Drill pipe	5 inch, capacity = 0.01776 bbl/ft
Heavy wall drill pipe	5 inch, 630 feet long, Capacity = 0.0088 bbl/ft.
Drill collars	8 inch, 542 feet long, capacity = 0.0061 bbl/ft
Mud density	10.5 ppg

Capacities

Drill collars in open hole	0.086 bbl/ft
Drill pipe in open hole	0.1251 bbl/ft
Drill pipe in casing	0.1238 bbl/ft
Mud Pumps displacement	0.11 bbl/Stroke
Slow Circulating Rate	750 psi at 30 spm

A leak-off test was carried out at the 13 3/8 casing shoe using a mud density off 9.8 ppg and a surface pressure of 1600 psi was recorded.

The well was been shut in the following a kick

Kick Data

Shut-in Drill Pipe Pressure	800 psi
Shut-in Casing pressure	1100 psi
Pit Gain	60 bbl

Answer the following question from the data above

1. How many strokes are required to pump kill mud from surface to bit?	= …... stroke
2. How many strokes are required to pump from bit to casing shoe?	= …… stroke
3. How many strokes are required to pump from bit to surface?	= …... stroke
4. What is the kill mud density?	= …… ppg
5. What is the initial circulating pressure?	= …… psi
6. What is the Final circulating pressure?	= …… psi
7. What is the MAASP at the time the well was shut in?	=…... Psi
8. What is the MAASP after circulation of the kill mud?	= …… psi
9. What is the time for one complete circulation?	= …… Minute
10. What is the drill pipe pressure reduction per 100 strokes as kill mud is being pumped to the bit?	= …… psi/100stk

Kill Sheet #4

Well Data

Hole size	8 3/8 inch
Hole depth	11095 feet TVD/MD
Casing	9 5/8 casing set at 8856 feet TVD/MD
Drill pipe	5 inch, capacity = 0.0178 bbl/ft
Heavy wall drill pipe	5 inch, 630 feet long, capacity = 0.0088 bbl/ft
Drill collars	6 ½ inch, 450 feet long, capacity = 0.0077 bbl/ft
Mud density	12 ppg
Surface lines volume	7 bbls

Capacities

Drill collars in open hole	0.0271 bbl/ft
Heavy wall drill pipe in open hole	0.0439 bbl/ft
Drill pipe in open hole	0.0439 bbl/ft
Drill pipe in casing	0.0493 bbl/ft
Mud pumps displacement	0.109 bbl/stroke
Slow circulating rate	450 psi at 40 spm

A leak-off test was carried out at the 9 5/8 casing shoe using a mud density off 10.3 ppg and a surface pressure of 1700 psi was recorded

The well has been shut in following a kick

Kick data

Shut-in drill pipe pressure	650 psi
Shut-in casing pressure	850 psi
Pit gain	15 bbls

Answer the following questions from the data above

1. What is the kill mud density? =…...ppg
2. What is the maximum allowable mud density? = …...ppg
3. How many strokes are required to pump kill mud from surface to bit? = …...strokes
4. How many strokes are required to pump from bit to casing shoe? = …...strokes
5. What is the total annular volume? = …...bbl
6. What is the initial circulating pressure? = …psi
7. What is the final circulating pressure? = …...psi
8. What is the MAASP at the time the well was shut in? = …...psi
9. What is the MAASP after circulation of the kill mud? = ……psi
10. What is the time for one complete circulation = ……minute

Kill Sheet #5

Well Data

Hole size	12 1/4 inch
Hole depth	12900 feet MD/ 11680 feet TVD
Casing	13 3/8 casing set at 4100 feet TVD/MD
Drill pipe	5 inch, capacity = 0.0177 bbl/ft
Drill collars	6 ½ inch, 590 feet long, capacity = 0.0077 bbl/ft
Mud density	12 ppg
Surface lines volume	5 bbls

Capacities

Drill collars in open hole	0.084 bbl/ft
Drill pipe in open hole	0.12 bbl/ft
Drill pipe in casing	0.13 bbl/ft
Mud pumps displacement	0.103 bbl/stroke
Slow circulating rate	670 psi at 30 spm

A leak-off test was carried out at the 13 3/8 casing shoe using a mud density off 10.6 ppg and a surface pressure of 1380 psi was recorded

The well has been shut in following a kick

Kick data

Shut-in drill pipe pressure	580 psi
Shut-in casing pressure	740 psi
Pit gain	19 bbls

Answer the following questions from the data above

1. What is the kill mud density? =…...ppg
2. What is the maximum allowable mud density? = …...ppg
3. How many strokes are required to pump kill mud from surface to bit? = …...strokes
4. How many strokes are required to pump from bit to casing shoe? = …...strokes
5. What is the total annular volume? = …...bbl
6. What is the initial circulating pressure? = …psi
7. What is the final circulating pressure? = …...psi
8. What is the MAASP at the time the well was shut in? = …...psi
9. What is the MAASP after circulation of the kill mud? = ……psi
10. What is the time for one complete circulation = ……minute

Kill Sheet #6

Well Data

Hole size	8 1/2 inch
Hole depth	12336 feet MD/TVD
Casing	9 5/8 casing set at 9875 feet TVD/MD
Drill pipe	5 inch, capacity 0.0178 bbl/ft
Heavy Weight Pipe	5 inch, 489 feet long, capacity 0.0088 bbl/ft
Drill collars	6 ¼ inch, 902 feet long, capacity 0.006 bbl/ft
Mud density	14.1 ppg

Capacities

Drill collars in open hole	0.0322 bbl/ft
DrillPipe/HWDP in open hole	0.0473 bbl/ft
Drill pipe in casing	0.0493 bbl/ft

Pumps	Displacement = 0.102 bbl/Stroke
Slow circulating rate	650 psi at 30 spm

Fracture mud density at the casing shoe 16.6 ppg

The well has been shut in after a kick

Kick data

Shut-in drill pipe pressure	530 psi
Shut-in casing pressure	720 psi
Pit gain	10 bbls

The well will be killed using the Driller's Method at 30 SPM

Answer the following questions from the data above

1. What is the kill mud density? =…...ppg
2. How many strokes are required to pump kill mud from surface to bit? = …...strokes
3. How many strokes are required to pump from bit to casing shoe? = …...strokes
4. How many strokes are required to pump from bit to surface? = …...strokes
5. What is the initial circulating pressure? = …psi
6. What is the final circulating pressure? = …...psi
7. What is the MAASP at the time the well was shut in? = …...psi
8. What is the MAASP after circulation of the kill mud? = ……psi
9. What is the time for one complete circulation = ……minute

Kill Sheet #1

1. What is the kill mud density? = …12.36-12.4... ppg
2. How many strokes are required to pump kill mud from surface to bit? = …1111-1112… stroke
3. How many strokes are required to pump from bit to casing shoe? = …2464-2465... stroke
4. How many strokes are required to pump from bit to surface? = …8007-8008… stroke
5. What is the MAASP at the time the well was shut in? = …1588 – 1588.6... Psi
6. What is the MAASP after circulation of the kill mud? = …1047-1061.32… psi
7. How many strokes are required for one complete circulation? =…9118-9119... Stroke
8. What is the Initial Circulating pressure? = …1750… psi
9. What is the Final circulating pressure? = …1087.2-1091… psi
10. What is the drill pipe pressure reduction per 100 strokes as kill mud is being pumped to the bit? = …59-60… psi/100stk

Kill Sheet #2

1. What is the kill mud density? = …13.48-13.5... ppg
2. What is the MAASP at the time the well was shut in? = …1482… psi
3. How many strokes are required to pump kill mud from surface to bit? = …1036-1037... stroke
4. How many strokes are required to kill mud from bit to surface? = …2933-2934… stroke
5. How many strokes are required to pump from bit to casing shoe? = …949-950… Stroke
6. What is the time for one complete circulation? = …112.4-114.4... Minute
7. How many strokes are required for one complete circulation? =…3970-3971... Stroke
8. What is the initial circulating pressure? = …1850… psi
9. What is the final circulating pressure? = …1215.4-1218… psi
10. What is the drill pipe pressure reduction per 100 strokes as kill mud is being pumped to the bit? = …61-62… psi/100stk

Kill Sheet #3

1. How many strokes are required to pump kill mud from surface to bit? = …1845-1883... stroke
2. How many strokes are required to pump from bit to casing shoe? = …3862-3941… stroke
3. How many strokes are required to pump from bit to surface? = …13466-13739... stroke
4. What is the kill mud density? = …12.00-12.1… ppg
5. What is the initial circulating pressure? = …1550… psi
6. What is the Final circulating pressure? = …857.14-865… psi
7. What is the MAASP at the time the well was shut in? =…1352-1362.14... Psi
8. What is the MAASP after circulation of the kill mud? = …811-855… psi
9. What is the time for one complete circulation? = …514.5-516.5… Minute
10. What is the drill pipe pressure reduction per 100 strokes as kill mud is being pumped to the bit? = …36-38… psi/100stk

Kill Sheet #4

1. What is the kill mud density? =…13.12-13.2...ppg
2. What is the maximum allowable mud density? = …13.9 – 13.99...ppg
3. How many strokes are required to pump kill mud from surface to bit? = …1718........strokes
4. How many strokes are required to pump from bit to casing shoe? = …1013…....strokes
5. What is the total annular volume? = …527.3329...bbl
6. What is the initial circulating pressure? = …1100...psi
7. What is the final circulating pressure? = …491.9 - 495...psi
8. What is the MAASP at the time the well was shut in? = …874 – 916.41...psi
9. What is the MAASP after circulation of the kill mud? = …322 – 400.6…psi
10. What is the time for one complete circulation = …163.9-164…minute

Kill Sheet #5

1. What is the kill mud density? =…12.95-13.0...ppg
2. What is the maximum allowable mud density? = …17.0 – 17.07...ppg
3. How many strokes are required to pump kill mud from surface to bit? = …2159-2160...strokes
4. How many strokes are required to pump from bit to casing shoe? = …10046 - 10047...strokes
5. What is the total annular volume? = …1567.76...bbl
6. What is the initial circulating pressure? = …1250...psi
7. What is the final circulating pressure? = …723.04 - 726...psi
8. What is the MAASP at the time the well was shut in? = …1066 – 1080.92...psi
9. What is the MAASP after circulation of the kill mud? = …863 – 878.38…psi
10. What is the time for one complete circulation = …579.34-580…minute

Kill Sheet #6

1. What is the kill mud density? =…14.92 to 15...ppg
2. How many strokes are required to pump kill mud from surface to bit? = …1985 to 2025...strokes
3. How many strokes are required to pump from bit to casing shoe? = …665 to 1018...strokes
4. How many strokes are required to pump from bit to surface? = ….5723 to 5839..strokes
5. What is the initial circulating pressure? = …1180...psi
6. What is the final circulating pressure? = …677 - 707...psi
7. What is the MAASP at the time the well was shut in? = …1283 ...psi
8. What is the MAASP after circulation of the kill mud? = …771 to 871…psi
9. What is the time for one complete circulation = …257-263…minute

Part 5: Gauge Problems

Driller's Method - #01

International Well Control Forum

Surface BOP Kill Sheet - Deviated Well (API Field Units)

DATE : ____________________

NAME : ____________________

FORMATION STRENGTH DATA:

SURFACE LEAK -OFF PRESSURE FROM FORMATION STRENGTH TEST (A) 1500 psi

MUD WEIGHT AT TEST (B) 10 ppg

MAXIMUM ALLOWABLE MUD WEIGHT =

$(B) + \frac{(A)}{\text{SHOE T.V. DEPTH} \times 0.052} =$ (C) 15.4 ppg

INITIAL MAASP =

((C) - CURRENT MUD WEIGHT) x SHOE T.V. DEPTH x 0.052

= 1322 psi

CURRENT WELL DATA:

DRILLING MUD DATA:

WEIGHT 10.6 ppg

GRADIENT 0.551 psi/ft

DEVIATION DATA:

KOP M.D. 3000 ft

KOP T.V.D. 3000 ft

EOB M.D. 8500 ft

EOB T.V.D. 5750 ft

CASING SHOE DATA:

SIZE 9-5/8 in

M. DEPTH 8600 ft

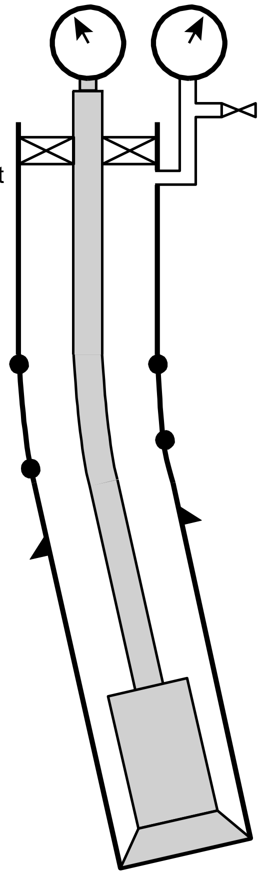
T.V. DEPTH 5300 ft

HOLE DATA:

SIZE 8-1/2 in

M. DEPTH 12000 ft

T.V. DEPTH 6000 ft



PUMP NO. 1 DISPL.	PUMP NO. 2 DISPL.
0.1 bbls / stroke	bbls / stroke

SLOW PUMP RATE DATA:	(PL) DYNAMIC PRESSURE LOSS PUMP NO. 1	PUMP NO. 2
30 SPM	350 psi	psi
SPM	psi	psi

PRE-RECORDED VOLUME DATA:	LENGTH ft		CAPACITY bbls / ft		VOLUME bbls		PUMP STROKES strokes		TIME minutes	
DP - SURFACE TO KOP	3000	x	0.0176	=	52.80		(L) 528	stks		
DP - KOP TO EOB	5500	x	0.0176	=	96.80	+	(M) 968	stks		
							(N1) 387	stks		
HEVI WALL DRILL PIPE	800	x	0.0087	=	6.9	+	(N2) 70	stks		
DRILL COLLAR	500	x	0.0076	=	3.8	+	(N3) 38	stks		
DRILL STRING VOLUME					(D) 199	bbls	1990	stks	66	min
DC x OPEN HOLE	500	x	0.021	=	10.50					
DP / HWDP x OPEN HOLE	2900	x	0.045	=	130.50	+				
OPEN HOLE VOLUME					(F) 141	bbls	1410	stks	47	min
DP x CASING	8600	x	0.049	=	(G) 421.40	+	4214	stks	140.5	min
TOTAL ANNULUS VOLUME					(F+G) = (H) 562.40	bbls	5624	stks	187.5	min
TOTAL WELL SYSTEM VOLUME					(D+H) = (I) 761.40	bbls	7614	stks	254	min
ACTIVE SURFACE VOLUME					(J)	bbls				
TOTAL ACTIVE FLUID SYSTEM					(I+J)	bbls				

Dr No SD 04/01
(Field Units)
27-01-2000

International Well Control Forum

Surface BOP Kill Sheet - Deviated Well (API Field Units)

DATE :

NAME :

KICK DATA :

SIDPP	800	psi	SICP	900	psi	PIT GAIN	20	bbl

KILL MUD WEIGHT KMW	CURRENT MUD WEIGHT + $\frac{\text{SIDPP}}{\text{TVD x 0.052}}$ 10.6 + $\frac{800}{6000 \text{ X } 0.052}$ =	13.16 ppg
INITIAL CIRC. PRESSURE ICP	DYNAMIC PRESSURE LOSS + SIDPP 350 + 800 =	1150 psi
FINAL CIRCULATING PRESSURE FCP	$\frac{\text{KILL MUD WEIGHT}}{\text{CURRENT MUD WEIGHT}}$ x DYNAMIC PRESSURE LOSS $\frac{13.16}{10.6}$ x 350 =	435 psi
DYNAMIC PRESSURE LOSS AT KOP (O)	PL + [(FCP-PL) x $\frac{\text{KOPMD}}{\text{TDMD}}$] = 350 + [(435 - 350) x $\frac{3000}{12000}$] =	371 psi
REMAINING SIDPP AT KOP (P)	SIDPP - [(KMW - CMW) x 0.052 x KOPTVD] = 800 - [(13.16 - 10.6) x 0.052 x 3000 =]	401 psi
CIRCULATING PRESS. AT KOP (KOP CP)	(O) + (P) = 371 + 401 =	772 psi
DYNAMIC PRESSURE LOSS AT EOB (R)	PL + [(FCP-PL) x $\frac{\text{EOBMD}}{\text{TDMD}}$] = 350 + [(435 - 350) x $\frac{8500}{12000}$] =	410 psi
REMAINING SIDPP AT EOB (S)	SIDPP - [(KMW - CMW) x 0.052 x EOBTVD] = 800 - [(13.16 - 10.6) x 0.052 x 5750 =]	35 psi
CIRCULATING PRESSURE AT EOB (EOB CP)	(R) + (S) = 410 + 35 =	445 psi

(T) = ICP - KOP CP = 1150 - 772 = 378 psi	$\frac{\text{(T) x 100}}{\text{(L)}}$ = $\frac{378 \text{ x } 100}{528}$ = 72	$\frac{\text{psi}}{\text{100 strokes}}$
(U) = KOP CP - EOB CP = 772 - 445 = 327 psi	$\frac{\text{(U)x100}}{\text{(M)}}$ = $\frac{327 \text{ X}100}{968}$ = 34	$\frac{\text{psi}}{\text{100 strokes}}$
(W) = EOB CP - FCP = 445 - 435 = 10 psi	$\frac{\text{(W) x 100}}{\text{(N1+N2+N3)}}$ = $\frac{10 \text{ X } 100}{495}$ = 2	$\frac{\text{psi}}{\text{100 strokes}}$

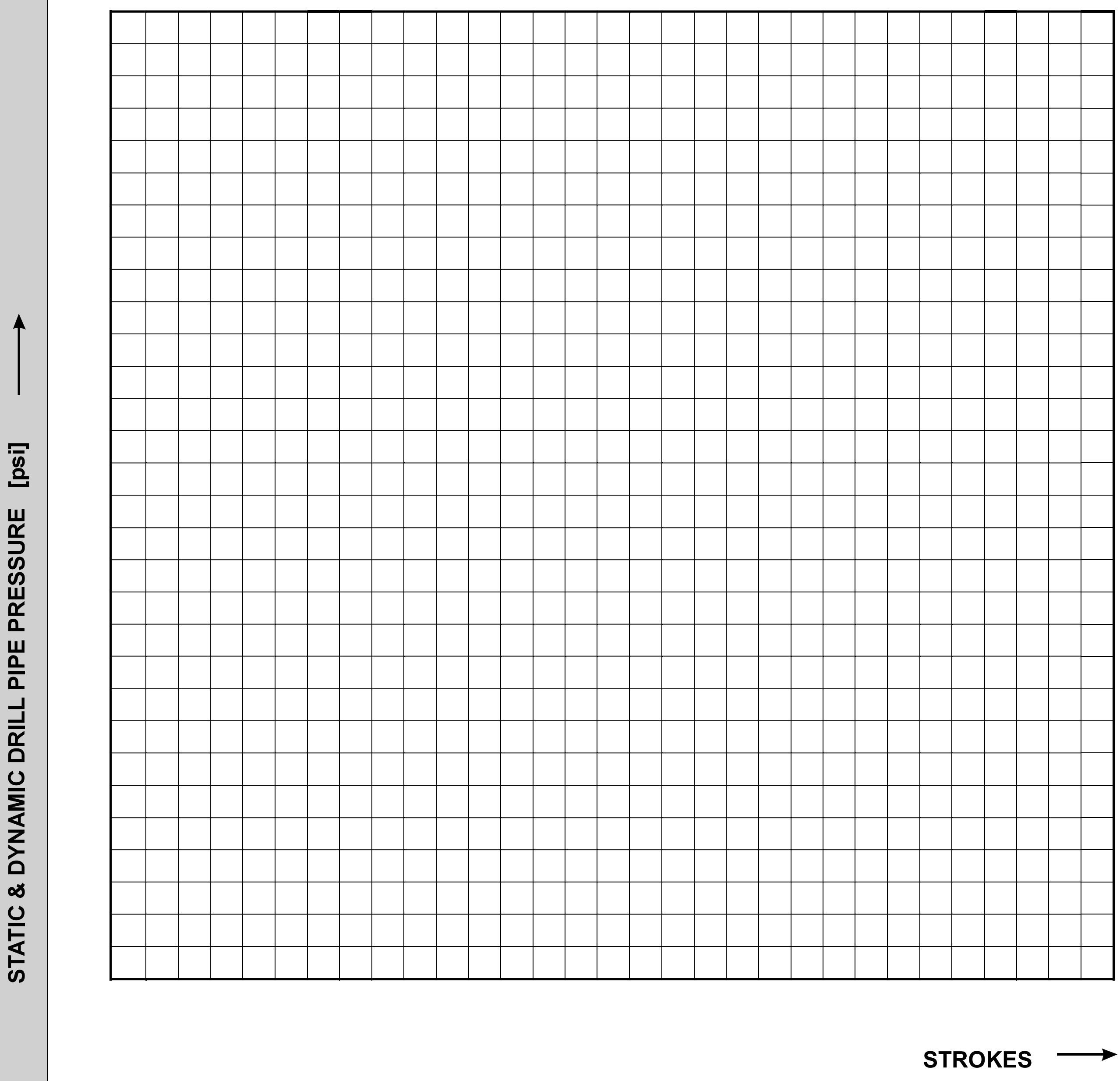
Dr No SD 04/02 (Field Units) 27-01-2000

International Well Control Forum

Surface BOP Kill Sheet - Deviated Well (API Field Units)

DATE : ______________________

NAME : ______________________



PRESSURE [psi]	1150	1078	1006	934	862	790	772	738	704	670	636	602	568	534	500	466	445	443	441	439	437	435	435							
STROKES	0	100	200	300	400	500	528	600	700	800	900	1000	1100	1200	1300	1400	1496	1500	1600	1700	1800	1900	1990							

Driller's Method - #01

Use the information from the completed Kill sheet on the previous pages to answer the following ELEVEN questions. The well will be killed using the Driller's Method at 30 SPM. Ignore the surface line volume.

1. After 60 strokes have been circulated the following gauge readings are observed on the remote choke panel:

Drill pipe pressure	**900 psi**
Casing pressure	**750 psi**
Pump speed	**30 spm**
Strokes pumped	**60 strokes .**

What action should be taken?

a. Open the choke more.
b. Close the choke more.
c. Increase the pump rate.
d. Decrease the pump rate.
e. Continue - Everything is OK.

2. After 510 strokes have been circulated the following readings are observed on the remote choke panel:

Drill pipe pressure	**1160 psi**
Casing pressure	**1020 psi**
Pump speed	**30 spm**
Strokes pumped	**510 strokes**

What action should be taken?

a. Open the choke more.
b. Close the choke more.
c. Increase the pump rate.
d. Decrease the pump rate.
e. Continue - everything is OK.

3. **After 600 strokes have been circulated the following readings are observed on the remote choke panel:**

Drill pipe pressure	**1130 psi**
Casing pressure	**1030 psi**
Pump speed	**28 spm**
Strokes pumped	**600 strokes**

What action should be taken?

a. Open the choke more.

b. Close the choke more.

c. Increase the pump rate.

d. Decrease the pump rate.

e. Continue - everything is OK.

4. **After 4000 strokes have been circulated, the following readings are observed on the remote choke panel:**

Drill pipe pressure	**1160 psi**
Casing pressure	**1310 psi**
Pump speed	**30 sprn**
Strokes pumped	**4000 strokes**

The casing pressure has now started to increase faster than before. What is the most likely reason for this?

a. The circulating rate is below the required bottom hole pressure and more influx is entering the well.

b. The influx is being circulated from highly deviated section into the build section of the well.

c. The change is caused by the effect of gas free mud in the horizontal section of the well.

d. The choke is partially plugged.

5. **After 5000 strokes have been circulated, the following readings are observed on the remote choke panel:**

Drill pipe pressure	**1170 psi**
Casing pressure	**1400 psi**
Pump speed	**30 spm**
Strokes pumped	**5000 strokes**

What action should be taken?

a. Open the choke more - MAASP has been exceeded.

b. Close the choke little.

c. Slow the pumps down to reduce circulating friction in the annulus.

d. Continue - Everything is OK.

6. **After 6500 strokes have been circulated, the pump is shuts down while holding casing pressure constant.**

Provided that no more influx was allowed to enter the well during the first circulation of driller's method, what reading would you expect to see on the drill pipe pressure gauge on the remote choke panel?

a. 435 psi.

b. 800 psi.

c. 900 psi.

d. 0 psi.

7. **Provided that no more influx was allowed to enter the well during the first circulation of driller's method, what reading would you expect to see on the casing pressure gauge on the remote choke panel?**

a. 345 psi.

b. 800 psi.

c. 900 psi.

d. 0 psi.

8. Kill mud is now being pumped into the well.

After 1000 strokes have been circulated, the following readings are observed on the remote choke panel:

Drill pipe pressure	**700 psi**
Casing pressure	**900 psi**
Pump speed	**30 spm**
Strokes pumped	**1000 strokes**

What action should be taken?

a. Open the choke more.

b. Close the choke little.

c. Increase the pump rate.

d. Decrease the pump rate.

e. Continue - Everything is OK.

9. After 2500 strokes have been circulated, the drill pipe pressure suddenly increases while the casing pressure remains constant.

Drill pipe pressure	**640 psi**
Casing pressure	**700 psi**
Pump speed	**30 spm**
Strokes pumped	**2500 strokes**

What action should be taken?

a. Shut the well in and analyze the problem.

b. Open the choke more.

c. Close the choke little.

d. Increase the pump rate.

e. Decrease the pump rate.

10. How do you explain the previous problem?

a. A lost bit nozzle.

b. A washout in the drill pipe.

c. A plugged bit nozzle.

d. A pump problem.

e. A washout in the choke.

f. A plugged choke.

11. The choke is now fully open and the kill mud is returning to surface, but it is difficult to determine whether there is any pressure on the casing.

The following readings are observed on the remote choke panel:

Drill pipe pressure	**640 psi**
Casing pressure	**0 psi**
Pump speed	**30 spm**
Strokes pumped	**8000 strokes**

What action should be taken?

a. Open the choke more.

b. Close the choke little.

c. Stop the pump, shut in the well, observe pressures.

d. Reduce the pump rate.

e. Stop pumping and open the well.

Driller's Method - #02

International Well Control Forum

Surface BOP Kill Sheet - Deviated Well (API Field Units)

DATE : ____________________

NAME : ____________________

FORMATION STRENGTH DATA:

SURFACE LEAK -OFF PRESSURE FROM FORMATION STRENGTH TEST (A) 1125 psi

MUD WEIGHT AT TEST (B) 10.4 ppg

MAXIMUM ALLOWABLE MUD WEIGHT =

$$(B) + \frac{(A)}{\text{SHOE T.V. DEPTH} \times 0.052} = (C)\ 14.6\ \text{ppg}$$

INITIAL MAASP =

((C) - CURRENT MUD WEIGHT) x SHOE T.V. DEPTH x 0.052

= 981 psi

PUMP NO. 1 DISPL.	PUMP NO. 2 DISPL.
0.12 bbls / stroke	bbls / stroke

SLOW PUMP RATE DATA:	(PL) DYNAMIC PRESSURE LOSS PUMP NO. 1	PUMP NO. 2
30 SPM	625 psi	psi
SPM	psi	psi

CURRENT WELL DATA:

DRILLING MUD DATA:

WEIGHT	10.9	ppg
GRADIENT		psi/ft

DEVIATION DATA:

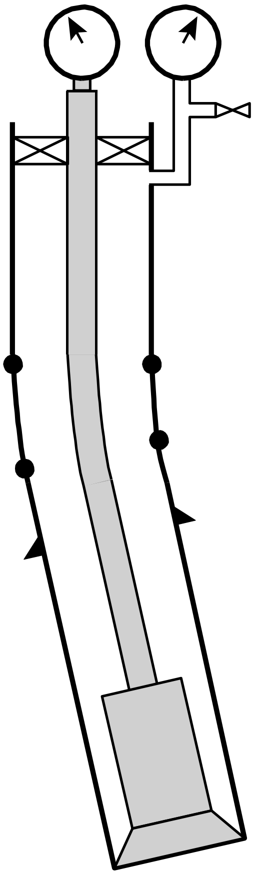
KOP M.D.		ft
KOP T.V.D.		ft
EOB M.D.		ft
EOB T.V.D.		ft

CASING SHOE DATA:

SIZE	9-5/8	in
M. DEPTH	6200	ft
T.V. DEPTH	5100	ft

HOLE DATA:

SIZE	8-1/2	in
M. DEPTH	11950	ft
T.V. DEPTH	6100	ft



PRE-RECORDED VOLUME DATA:	LENGTH ft	CAPACITY bbls / ft		VOLUME bbls		PUMP STROKES strokes	TIME minutes
DP - SURFACE TO KOP	3000	x0.01750 =		52.50		(L) 438 stks	
DP - KOP TO EOB	2900	x0.01750 =		50.75	+	(M) 423 stks	
DP - EOB TO BHA	5720	x0.01750 =		100.10	+	(N1) 834 stks	

International Well Control Forum

Surface BOP Kill Sheet - Deviated Well (API Field Units)

DATE : ____________________

NAME : ____________________

KICK DATA :

SIDPP 875 psi | SICP 905 psi | PIT GAIN 15 bbl

KILL MUD WEIGHT KMW	CURRENT MUD WEIGHT + $\frac{\text{SIDPP}}{\text{TVD} \times 0.052}$ 10.9 .... + $\frac{875}{6100 \times 0.052}$ = 13.7 .... ppg
INITIAL CIRC. PRESSURE ICP	DYNAMIC PRESSURE LOSS + SIDPP 625 .... + 875 .... = 1500 .... psi
FINAL CIRCULATING PRESSURE FCP	$\frac{\text{KILL MUD WEIGHT}}{\text{CURRENT MUD WEIGHT}}$ x DYNAMIC PRESSURE LOSS $\frac{13.7}{10.9}$ x 625 .... = 785 .... psi
DYNAMIC PRESSURE LOSS AT KOP (O)	PL + [(FCP-PL) x $\frac{\text{KOPMD}}{\text{TDMD}}$] = 625 + [(785 - 625) x $\frac{3000}{11950}$] = 665 .... psi
REMAINING SIDPP AT KOP (P)	SIDPP - [(KMW - CMW) x 0.052 x KOPTVD] = ... - [(..................-...................) x 0.052 x .... =] .... psi
CIRCULATING PRESS. AT KOP (KOP CP)	(O) + (P) = 371 .... + 401 .... = ... psi
DYNAMIC PRESSURE LOSS AT EOB (R)	PL + [(FCP-PL) x $\frac{\text{EOBMD}}{\text{TDMD}}$] = ... + [(...........-............) x ————] = ... psi
REMAINING SIDPP AT EOB (S)	SIDPP - [(KMW - CMW) x 0.052 x EOBTVD] = ... - [(..................-...................) x 0.052 x .... =] .... psi
CIRCULATING PRESSURE AT EOB (EOB CP)	(R) + (S) = ... + ... = ... psi

(T) = ICP - KOP CP = ... - .... = ... psi	$\frac{(T) \times 100}{(L)}$ = $\frac{\quad \times 100}{\quad}$ = ... $\frac{\text{psi}}{\text{100 strokes}}$
(U) = KOP CP - EOB CP = ... - .... = ... psi	$\frac{(U) \times 100}{(M)}$ = $\frac{\quad \text{X } 100}{\quad}$ = ... $\frac{\text{psi}}{\text{100 strokes}}$
(W) = EOB CP - FCP = ... - .... = ... psi	$\frac{(W) \times 100}{(N1+N2+N3)}$ = $\frac{\quad \text{X } 100}{\quad}$ = ... $\frac{\text{psi}}{\text{100 strokes}}$

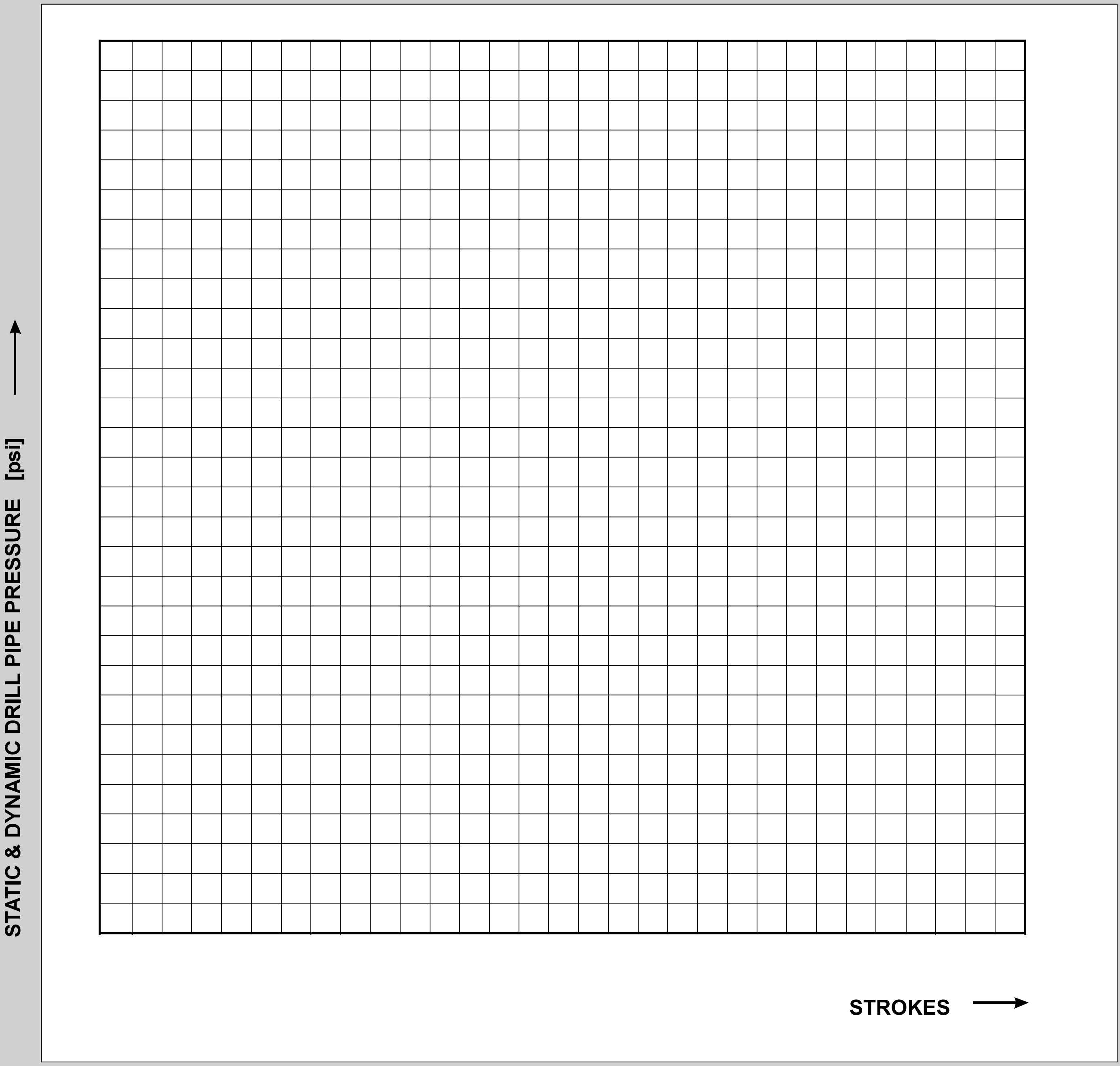
Dr No SD 04/02 (Field Units) 27-01-2000

International Well Control Forum

Surface BOP Kill Sheet - Deviated Well (API Field Units)

DATE : ______________________________

NAME : ______________________________



STROKES	0	100	200	300	400	438	500	600	700	800	861	900	1000	1100	1200	1300	1400	1500	1600	1700	1716									
PRESSURE [psi]	1500	1410	1320	1230	1140	1106	1068	1007	946	885	848	845	838	831	824	817	810	803	796	789	785									

Dr No SD 04/03 (Field Units) 27-01-2000

Driller’s Method - #02

Use the information from the completed Kill sheet on the previous pages to answer the following ELEVEN questions. The well will be killed using the Driller's Method at 30 SPM. Ignore the surface line volume.

1. After 4 minutes of circulation the following gauge readings are observed on the remote choke panel:

Drill pipe pressure	**1500 psi**
Casing pressure	**905 psi**
Pump speed	**30 spm**
Strokes pumped	**100 strokes .**

What action should be taken?

a. Open the choke more.

b. Close the choke more.

c. Increase the pump rate.

d. Decrease the pump rate.

e. Continue - Everything is OK.

2. After 8 minutes of circulation the following readings are observed on the remote choke panel:

Drill pipe pressure	**1500 psi**
Casing pressure	**905 psi**
Pump speed	**30 spm**
Strokes pumped	**220 strokes**

What action should be taken?

a. Open the choke more.

b. Close the choke more.

c. Increase the pump rate.

d. Decrease the pump rate.

e. Continue - everything is OK.

3. **After 1800 strokes have been circulated the following readings are observed on the remote choke panel:**

Drill pipe pressure	**1620 psi**
Casing pressure	**1090 psi**
Pump speed	**30 spm**
Strokes pumped	**1800 strokes**

What action should be taken?

a. Open the choke more.

b. Close the choke more.

c. Increase the pump rate.

d. Decrease the pump rate.

e. Continue - everything is OK.

4. **After 5000 strokes have been circulated, the well is shut in and the gauge readings are observed on the choke panel:**

Drill pipe pressure	**875 psi**
Casing pressure	**875 psi**
Pump speed	**0 sprn**
Strokes pumped	**5000 strokes**

What action should be taken?

a. Reset the stroke counters and start up holding casing pressure constant while bringing the pump to kill speed, and then hold the drillpipe pressure constant by following the diagram of the kill sheet till the heavy fluid is at the bit.

b. Start up holding drill pipe pressure constant.

c. Everything is OK. Continue kill procedure at 30 SPM and same final circulating pressure.

5. **The second circulation has commenced and kill fluid is being circulated. After 1800 strokes have been circulated, the following readings are observed on the remote choke panel:**

Drill pipe pressure	**785 psi**
Casing pressure	**875 psi**
Pump speed	**30 spm**
Strokes pumped	**1800 strokes**

What action should be taken?

a. Open the choke more.

b. Close the choke little.

c. Increase the pump rate.

d. Reduce the pump rate.

d. Continue - Everything is OK.

6. **After 1900 strokes have been circulated, the following readings are observed?**

Drill pipe pressure	**885 psi**
Casing pressure	**960 psi**
Pump speed	**30 SPM**
Strokes circulated	**1900 strokes**

What action should be taken?

a. Open the choke more

b. Close the choke more

c. Reduce the pump rate

d. Shut down and observe pressures

7. **After 2500 strokes have been circulated the following gauge readings are observed.**

Drill pipe pressure	**653 psi**
Casing pressure	**682 psi**
Pump Speed	**30 SPM**
Strokes circulated	**2500 strokes**

What action should be taken?

a. Open the choke more
b. Close the choke more
c. Increase the pump rate
d. Shut down and observe pressures.

8. **After 2800 strokes have been circulated the casing pressure and then the drill pipe pressure start to fluctuate and increase:**

Drill pipe pressure	**1075 psi**
Casing pressure	**1090 psi**
Pump speed	**30 spm**
Strokes pumped	**2800 strokes**

What is the problem?

a. A pump suction problem.
b. A plugged bit nozzle
c. A wash out in the drill string
d. A plugging choke
e. The pulsation dampener of the mud pump is malfunctioning.

9. After 3000 strokes have been circulated, the drill pipe pressure suddenly decreases. The casing pressure is not affected.

Drill pipe pressure	**508 psi**
Casing pressure	**785 psi**
Pump speed	**30 spm**
Strokes pumped	**3000 strokes**

What is the problem?

a. A pump problem.

b. A lost bit nozzle.

c. A wash out in the drill string.

d. A wash out in the choke manifold.

e. The U-tubing effect of the heavy kill fluid.

10. The previous problem has been solved.

After 4800 strokes have been circulated, it requires continuous small opening correction of the choke to maintain drill pipe pressure at 508 psi.

Drill pipe pressure	**508 psi**
Casing pressure	**580 psi**
Pump Speed	**30 SPM**
Strokes circulated	**4800 strokes**

What is the problem?

a. A bit nozzle washing out.

b. The choke washing out.

c. A wash out developing inside the fluid pump.

d. There is no problem. It is caused by the kill fluid rising up the annulus.

11. The choke is now fully open and the kill mud is returning to surface, but it is difficult to determine whether there is any pressure on the casing.

The following readings are observed on the remote choke panel:

Drill pipe pressure	**508 psi**
Casing pressure	**0 psi**
Pump speed	**30 spm**
Strokes pumped	**7000 strokes**

What action should be taken?

a. Open the choke more.

b. Close the choke little.

c. Stop the pump, shut in the well, observe pressures.

d. Reduce the pump rate.

e. Stop pumping and open the well.

Wait & Weight Method - #01

International Well Control Forum

Surface BOP Vertical Well Kill Sheet (API Field Units)

DATE : ______________________

NAME : ______________________

FORMATION STRENGTH DATA:

SURFACE LEAK -OFF PRESSURE FROM FORMATION STRENGTH TEST **(A)** ______ psi

MUD WEIGHT AT TEST **(B)** ______ ppg

MAXIMUM ALLOWABLE MUD WEIGHT =

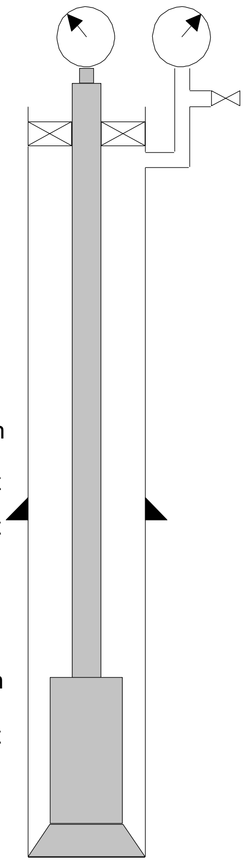
(B) + **(A)** / SHOE T.V. DEPTH x 0.052 = **(C)** ______ ppg

INITIAL MAASP =

((**C**) - CURRENT MUD WEIGHT) x SHOE T.V. DEPTH x 0.052

= 1100 psi

CURRENT WELL DATA::



CURRENT DRILLING MUD:

WEIGHT 11 ppg

CASING SHOE DATA:

SIZE 13 5/8 inch

M. DEPTH 6000 feet

T.V. DEPTH 5820 feet

HOLE DATA:

SIZE 12 1/4 inch

M. DEPTH 7550 feet

T.V. DEPTH 6000 feet

PUMP NO. 1 DISPL.	PUMP NO. 2 DISPL.
bbls / stroke	bbls / stroke

SLOW PUMP RATE DATA:	(PL) DYNAMIC PRESSURE LOSS [psi] PUMP NO. 1	PUMP NO. 2
30 SPM	500	500
SPM		

PRE-RECORDED VOLUME DATA:	LENGTH feet	CAPACITY bbls / foot	VOLUME barrels	PUMP STROKES strokes	TIME minutes
DRILL PIPE		x	=	**VOLUME / PUMP DISPLACEMENT**	**PUMP STROKES / SLOW PUMP RATE**
HEAVY WALL DRILL PIPE		x	= +		
DRILL COLLARS		x	= +		
DRILL STRING VOLUME			**(D)** bbls	**(E)** 1085 strokes	36 Min
DC x OPEN HOLE		x	=		
DP / HWDP x OPEN HOLE		x	= +		
OPEN HOLE VOLUME			**(F)** bbls	1420 strokes	47 Min
DP x CASING		x	=**(G)** +	strokes	Min
TOTAL ANNULUS VOLUME			**(F+G) = (H)** bbls	6519 strokes	217 Min
TOTAL WELL SYSTEM VOLUME			**(D+H)** = (I) bbls	9024 strokes	301 Min
ACTIVE SURFACE VOLUME			**(J)** bbls	strokes	
TOTAL ACTIVE FLUID SYSTEM			**(I +J)** bbls	strokes	

Dr No SV 04/01
(Field Units)
27-01-2000

International Well Control Forum

Surface BOP Kill Sheet - Vertical Well (API Field Units)

DATE : ____________________

NAME : ____________________

KICK DATA : SIDPP 550 psi SICP 650 psi PIT GAIN 25 barrels

KILL MUD WEIGHT

KMW

CURRENT MUD WEIGHT + SIDPP / (TVD x 0.052)

.... + ________ X 0.052 = 12.5 ppg

INITIAL CIRCULATING PRESSURE

ICP

DYNAMIC PRESSURE LOSS + SIDPP

.... + ... = 1050 psi

FINAL CIRCULATING PRESSURE

FCP

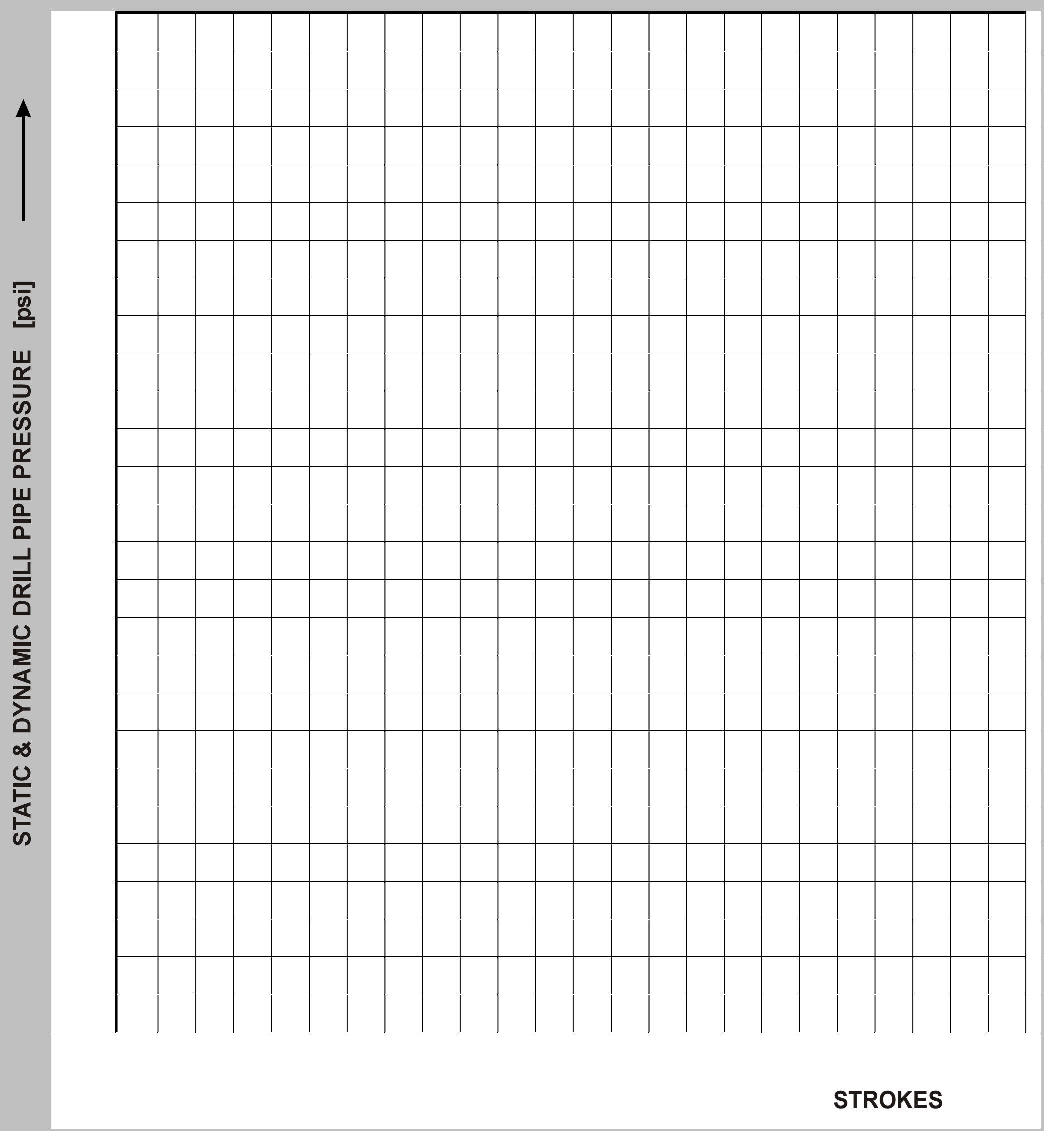
KILL MUD WEIGHT / CURRENT MUD WEIGHT x DYNAMIC PRESSURE LOSS

____________ x .... = 570 psi

(K) = ICP - FCP = ... - .... = ...480 psi

(K) x 100 / (E) = X 100 = 44.2 psi

STROKES	PRESSURE [psi]
0	1050
100	1006
200	962
300	917
400	873
500	820
600	785
700	741
800	695
900	652
1000	608
1085	570



Dr No SV 04/02 (Field Units) 27-01-2000

Wait & Weight Method - #01

Use the information from the completed Kill sheet on the previous pages to answer the following ELEVEN questions.
The well will be killed using the Wait and Weight Method at 30 SPM. Ignore the surface line volume.

1. After 139 strokes have been circulated the following gauge readings are observed on the remote choke panel:

Drill pipe pressure	**940 psi**
Casing pressure	**670 psi**
Pump speed	**25 spm**
Strokes pumped	**139 strokes**

What action should be taken?

a. Open the choke more.

b. Close the choke more.

c. Increase the pump rate.

d. Reduce the pump rate.

e. Continue - Everything is OK,

2. After 270 strokes have been circulated the following readings are observed on the remote choke panel:

Drill pipe pressure	**935 psi**
Casing pressure	**680 psi**
Pump speed	**30 spm**
Strokes pumped	**270 strokes**

What action should be taken?

a. Open the choke more.

b. Close the choke more.

c. Adjust pump rate.

d. Stop pumping and close the choke.

e. Continue - Everything is OK.

3. After 450 strokes have been circulated, the following readings are observed on the remote choke panel:

Drill pipe pressure	**855 psi**
Casing pressure	**690 psi**
Pump speed	**30 spm**
Strokes pumped	**450 strokes**

What action should be taken?

a. Open the choke more.

b. Close the choke more.

c. Increase the pump rate.

d. Reduce the pump rate.

e. Continue - Everything is OK.

4. After 870 strokes have been circulated, the following readings are observed on the remote choke panel:

Drill pipe pressure	**760 psi**
Casing pressure	**750 psi**
Pump speed	**30 spm**
Strokes pumped	**870 strokes**

What action should be taken?

a. Open the choke more.

b. Close the choke more.

c. Increase the pump rate.

d. Reduce the pump rate.

e. Continue - Everything is OK.

5. After 1150 strokes have been circulated, the well is shut in to make a check.

The following readings are observed on the remote choke panel:

Drill pipe pressure	**0 psi**
Casing pressure	**850 psi**
Pump speed	**0 spm**
Strokes pumped	**1150 strokes**

After the check the kill procedure is continued. What should be done?

a. The casing pressure is less than shut in pressure because the kill mud density is too high. Continue the kill procedure using a kill mud density corrected for the pressure difference.

b. Start up holding drill pipe pressure constant.

c. Start up holding casing pressure constant while bringing the pump to kill speed, then hold the observed drill pipe pressure constant.

d. Restart circulation at 30 spm maintaining the same final circulating pressure.

6. After 5500 strokes have been circulated, the following readings are observed on the remote choke panel:

Drill pipe pressure	**575 psi**
Casing pressure	**1430 psi**
Pump speed	**30 spm**
Strokes pumped	**5500 strokes**

What action should be taken?

a. Open the choke more.

b. Close the choke little.

c. Increase the pump rate.

d. Reduce the pump rate.

e. Continue - Everything is OK.

7. After 5900 strokes have been circulated, the drill pipe pressure suddenly decreased while the casing pressure remains steady.

Drill pipe pressure	**440 psi**
Casing pressure	**1460 psi**
Pump speed	**30 spm**
Strokes pumped	**5900 strokes**

What is the problem?

a. A lost bit nozzle.

b. A washout in the drill pipe.

c. A plugged bit nozzle.

d. A pump problem.

e. A washout in the choke.

f. A plugged choke.

8. What action should be taken?

a. Stop the pump and shut the well in.

b. Open the choke more.

c. Close the choke little.

d. Increase the pump rate.

e. Decrease the pump rate.

9. The problem has been identified, and the following gauge readings are now observed on the remote choke panel:

Drill pipe pressure	**440 psi**
Casing pressure	**1440 psi**
Pump speed	**33 spm**
Strokes pumped	**5920 strokes**

What action should be taken?

a. Continue - Everything is OK.

b. Reduce the pump rate.

c. Increase the pump rate.

d. Close the choke more.

e. Open the choke little.

10. After 6100 strokes have been circulated, the following readings are observed on the remote choke panel:

Drill pipe pressure	**440 psi**
Casing pressure	**1370 psi**
Pump speed	**30 spm**
Strokes pumped	**6100 strokes**

What action should be taken?

a. Continue - Everything is OK.

b. Reduce the pump rate.

c. Increase the pump rate.

d. Close the choke more.

e. Open the choke little.

11. After 9350 strokes have been circulated, the following readings are observed on the remote choke panel:

Drill pipe pressure	**440 psi**
Casing pressure	**0 psi**
Pump speed	**30 spm**
Strokes pumped	**9350 strokes**

The choke now fully open and there is no back pressure on the casing.

What action should be taken?

a. Close the choke more.

b. Stop the pump, shut the well in, observe pressures.

c. Open the BOP and then start drilling operations.

d. Reduce the pump rate.

Wait & Weight Method - #02

International Well Control Forum
Surface BOP Vertical Well Kill Sheet (API Field Units)

DATE : ____________________

NAME : ____________________

FORMATION STRENGTH DATA:

SURFACE LEAK -OFF PRESSURE FROM FORMATION STRENGTH TEST (A) ______ psi

MUD WEIGHT AT TEST (B) ______ ppg

MAXIMUM ALLOWABLE MUD WEIGHT =

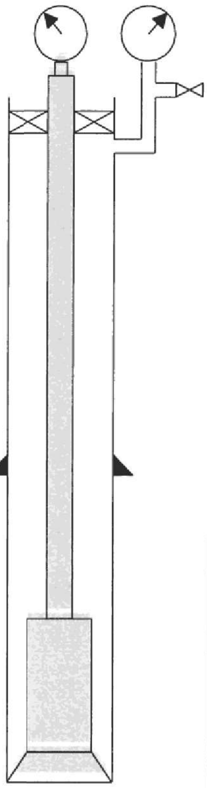
$$(B) + \frac{(A)}{\text{SHOE T.V. DEPTH} \times 0.052} = (C) \text{ ppg}$$

INITIAL MAASP =

((C) - CURRENT MUD WEIGHT) x SHOE T.V. DEPTH x 0.052

= 1170 psi

CURRENT WELL DATA::



CURRENT DRILLING MUD:

WEIGHT 12 ppg

CASING SHOE DATA:

SIZE 13-5/8 inch

M. DEPTH 7200 feet

T.V. DEPTH 6980 feet

HOLE DATA:

SIZE 12-1/4 inch

M. DEPTH 9580 feet

T.V. DEPTH 9186 feet

PUMP NO. 1 DISPL.	PUMP NO. 2 DISPL.
0.119 bbls / stroke	bbls / stroke

SLOW PUMP RATE DATA:	(PL) DYNAMIC PRESSURE LOSS [psi] PUMP NO. 1	PUMP NO. 2
30 SPM	450	
SPM		

PRE-RECORDED VOLUME DATA:	LENGTH feet	CAPACITY bbls / foot	VOLUME barrels	PUMP STROKES strokes	TIME minutes
DRILL PIPE	x		=	VOLUME / PUMP DISPLACEMENT	PUMP STROKES / SLOW PUMP RATE
HEAVY WALL DRILL PIPE	x		= +		
DRILL COLLARS	x		= +		
DRILL STRING VOLUME			(D) bbls	(E) 1380 strokes	46 Min
DC x OPEN HOLE	x		=		
DP / HWDP x OPEN HOLE	x		= +		
OPEN HOLE VOLUME			(F) bbls	2220 strokes	74 Min
DP x CASING	x		=(G) +	strokes	Min
TOTAL ANNULUS VOLUME			(F+G) = (H) bbls	10050 strokes	335 Min
TOTAL WELL SYSTEM VOLUME			(D+H) = (I) bbls	11430 strokes	381 Min
ACTIVE SURFACE VOLUME			(J) bbls	strokes	
TOTAL ACTIVE FLUID SYSTEM			(I +J) bbls	strokes	

Dr No SV 04/01
(Field Units)
27-01-2000

International Well Control Forum

Surface BOP Kill Sheet - Vertical Well (API Field Units)

DATE : ______________________

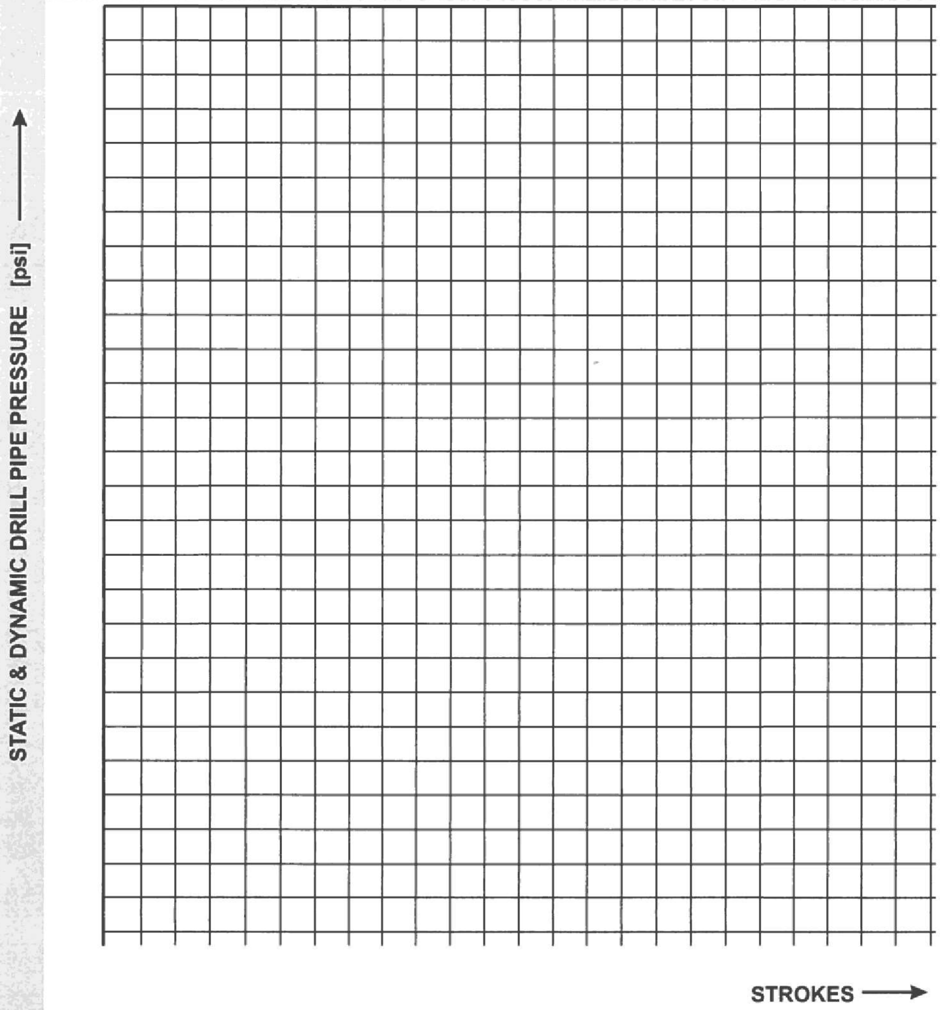
NAME : ______________________

KICK DATA : SIDPP **525** psi SICP **650** psi PIT GAIN **21** barrels

KILL MUD WEIGHT KMW	CURRENT MUD WEIGHT + SIDPP / (TVD x 0.052) .... + ________ / X 0.052 = **13.1** ppg
INITIAL CIRCULATING PRESSURE ICP	DYNAMIC PRESSURE LOSS + SIDPP .... + ... = **975** psi
FINAL CIRCULATING PRESSURE FCP	KILL MUD WEIGHT / CURRENT MUD WEIGHT x DYNAMIC PRESSURE LOSS ________ x .... = **490** psi

(K) = ICP - FCP = ... - .... = ...**485**.. psi | (K) x 100 / (E) = ________ X 100 = **35.15** psi / 100 strokes

STROKES	PRESSURE [psi]
0	975
100	940
200	905
300	870
400	835
500	800
600	765
700	730
800	695
900	660
1000	625
1100	590
1200	555
1300	520
1380	490



Dr No SV 04/02 (Field Units) 27-01-2000

Wait & Weight Method - #02

The well will be killed using the Wait and Weight Method at 30 SPM. Ignore the surface line volume.

1. **After 105 strokes are circulated, the remote choke panel shown the following readings:**

Drill pipe pressure	**769 psi**
Casing pressure	**638 psi**
Pump speed	**24 SPM**
Strokes pumped	**105 strokes**

What action should be taken?

a. Close the choke more.

b. Continue – everything is okay.

c. Increase the pump rate.

d. Open the choke more.

e. Reduce the pump rate

2. **After 240 strokes are circulated, the remote choke panel shows the following readings:**

Drill pipe pressure	**895 psi**
Casing pressure	**660 psi**
Pump speed	**30 SPM**
Strokes pumped	**240 strokes**

What action should be taken?

a. Close the choke more.

b. Continue – everything is okay.

c. Increase the pump rate

d. Open the choke more

e. Reduce the pump rate

3. After 420 strokes are circulated, the remote choke panel shows the following readings:

Drill pipe pressure	**830 psi**
Casing pressure	**680 psi**
Pump speed	**30 SPM**
Strokes pumped	**420 strokes**

What action should be taken?

a. Close the choke more.

b. Continue – everything is okay.

c. Increase the pump rate

d. Open the choke more

e. Reduce the pump rate

4. After 900 strokes are circulated, the remote choke panel shows the following readings:

Drill pipe pressure	**750 psi**
Casing pressure	**800 psi**
Pump speed	**30 SPM**
Strokes pumped	**900 strokes**

What action should be taken?

a. Close the choke more

b. Continue – everything is okay.

c. Increase the pump rate

d. Open the choke more

e. Reduce the pump rate

5. After reaching Final Circulating Pressure (FCP) after 1500 strokes circulated, the well is shut in to complete a pressure check. The remote choke panel then shows the following readings:

Drill pipe pressure	**0 psi**
Casing pressure	**730 psi**
Pump speed	**0 spm**
Strokes pumped	**1500 strokes**

After confirming the pressure check is acceptable, the kill procedure is continued.

What action should be taken?

a. Calculate the new kill fluid density and pump rate

b. Everything is okay, continue the kill procedure with 40 spm but keep the same FCP.

c. Start-up the kill procedure by holding casing pressure constant, while bringing the pump up to kill speed, then hold the observed drill pipe pressure constant.

d. Start-up the kill procedure by holding the drill pipe pressure constant, while bringing the pump up to kill speed, then hold the observed casing pressure constant.

6. After 3050 strokes are, the remote choke panel shows that both the drill pipe and casing pressure are decreasing:

Drill pipe pressure	**420 psi**
Casing pressure	**690 psi**
Pump speed	**30 spm**
Strokes pumped	**3050 strokes**

What is the reason for this decrease in pressure?

a. A lost bit nozzle

b. A plugged bit nozzle

c. A plugged choke

d. A pump problem

e. A washout in the choke

f. A washout in the drill pipe

7. After identifying the problem (from the previous question), what is the first action to take?

a. Change over to the back-up choke

b. Close the choke

c. Increase the pump rate

d. Stop the pump, and close one valve upstream of the choke

8. Once the problem (from the previous question) is resolved, the remote choke panel shows the following readings:

Drill pipe pressure	**490 psi**
Casing pressure	**720 psi**
Pump rate	**33 spm**
Strokes circulated	**3070 strokes**

What action should be taken?

a. Close the choke more

b. Continue – everything is okay

c. Increase the pump rate

d. Open the choke more

e. Reduce the pump rate

9. After 8000 strokes are circulated, the remote choke panel shows the following readings:

Drill pipe pressure	**490 psi**
Casing pressure	**800 psi**
Pump speed	**30 spm**
Strokes pumped	**8000 strokes**

What action should be taken?

a. Close the choke more

b. Continue – everything is okay

c. Increase the pump rate

d. Open the choke more

e. Reduce the pump rate

10. **After 9000 strokes are circulated, the remote choke panel shows the following readings:**

Drill pipe pressure	**410 psi**
Casing pressure	**840 psi**
Pump speed	**30 spm**
Strokes pumped	**9000 strokes**

What action should be taken?

a. Close the choke more

b. Continue – everything is okay

c. Increase the pump rate

d. Open the choke more

e. Reduce the pump rate

11. **After 12200 strokes are circulated, the remote choke panel shows the following readings:**

Drill pipe pressure	**490 psi**
Casing pressure	**0 psi**
Pump speed	**30 spm**
Strokes pumped	**12200 strokes**

The choke now fully open and the casing pressure gauge reads 0 psi.

What action should be taken?

a. Close the choke more.

b. Reduce the pump rate

c. Stop pumping and continue drilling

d. Stop pumping, shut the well in and monitor pressures

Driller’s method #01

1. B
2. E
3. C
4. B
5. D
6. B
7. B
8. A
9. A
10. C
11. C

Wait & Weight #01

1. C
2. E
3. E
4. A
5. C
6. E
7. A
8. A
9. B
10. A
11. B

Driller’s Method #02

1. E
2. E
3. A
4. A
5. D
6. A
7. B
8. D
9. B
10. D
11. C

Wait & Weight #02

1. C
2. B
3. B
4. D
5. C
6. E
7. D
8. E
9. B
10. A
11. D