



IWCF Workbook Well Intervention Level 3 / 4





PTS

IWCF Well Intervention
Well Control WORKBOOK

LEVEL 3/4



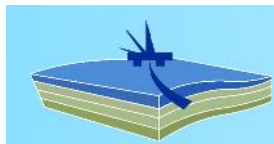


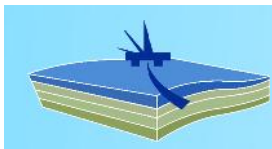
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COMPLETION OPERATIONS – PRINCIPLES & PROCEDURES

EXERCISE COMPLETION OPERATIONS 1

Given Well Data:

Well Depth (MD) = 12,650 ft (MD) and 11,353 ft (TVD)

Current Formation Pressure = 5,903 psi

Answer question # 1 and 2

1. What is the minimum fluid density required to kill the well given estimated Formation Pressure above?

Answer: _____ppg

2. The pressure gradient of production fluid (fluid/gas) inside the tubing is 0.13 psi/ft. What is the expected [surface] Tubing Head Pressure?

Answer: _____psi

3. A gas well has a total depth of 15,000 ft MD or 13,200 ft TVD

Packer is set at: 11,500 ft MD or 9,800 ft TVD

Shut-in wellhead pressure: 2,700 psi

Gas pressure gradient: 0.15 psi/ft

The Annulus is full of: 9.0 ppg brine

What is the differential pressure between tubing and annulus at the underside of the Tubing Hanger?

Answer: _____psi

4. The following information had been collected from a gas well prior running the production casing and installing wellhead equipment: -

Well Depth: 13,200 ft MD and 6,500 ft TVD

Form. Press. Gradient: 0.5720 psi/ft

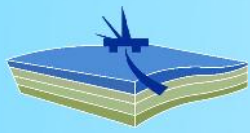
Gas Gradient: 0.0707 psi/ft

a) Calculate Formation Pressure: Answer: _____psi

b) Calculate Max. Surface Pressure: Answer: _____psi

c) What should be Rated Working Press of Xmas Tree? Answer: _____psi





5. Refer to Well Data on Question-4: -

The 7" Casing has now been run to the bottom of the well after which 3-1/2" OD completion string is run and landed in the Tubing Head Spool. Before we perforate the production zone, drilling mud in the well must be displaced with brine such that we will BALANCE the formation pressure. Calculate Brine Density required for this operation?

Answer_____ppg

6. In a production oil well, a Sliding Sleeve [SSD] has to be opened.
Well data is as follows:

End-of-Tubing:	9,175 ft MD and 8,100 ft TVD
Packer depth:	8,500 ft MD and 7,250 ft TVD
SSD depth:	8,100 ft MD and 6,825 ft TVD
Density Compl. Fluid:	9.2 ppg
Density of Oil:	6.8 ppg
SITHP:	750 psi

- a) Calculate the differential pressure across the SSD

Answer_____psi

- b) Referring to the previous question, which side of the SSD has a higher pressure?

Answer: _____

7. A well is to be killed with 10.0 ppg brine. The well depth is 12,000 ft MD and 11,000 ft TVD. The formation pressure is 5,620 psi.
Calculate the overbalance in this well after heavy brine has been pumped?

Answer:_____psi

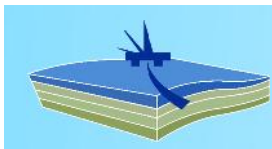
8. Well data is as follows:

Well depth:	6,150 ft TVD and 12,500 ft MD
Pore Press. Gradient:	0.572 psi/ft
Gas Gradient:	0.0707 psi/ft

Calculate the Maximum Surface Pressure prior installation of production casing and wellhead equipment.

Answer:_____psi (approx.)





9. Well Data is as follows: -

Tubing Depth:	9,500 ft MD and 8,700 ft TVD
Tubing Capacity:	0.0025 bbl/ft
Annular Capacity:	0.0052 bbl/ft
Pump Rate:	0.75 bbl/minute

For a forward circulation (i.e. pump down the tubing and up into annulus), calculate time required (in minutes) to pump bottoms up and to pump a full circulation?

[NOTE: Packer is unseated, i.e. we can circulate past the Packer]

- a) Calculate the time required to pump bottoms up?

Answer: _____ minutes

- b) Calculate the time required for a full circulation?

Answer: _____ minutes

10. The Well Data is as follows: -

Well Depth:	12,200 ft MD and 6,120 ft TVD
Tubing shoe depth:	11,000 ft. MD and 5,980 ft TVD
Formation Pore Press. Gradient:	0.572 psi/ft
Gas Gradient:	0.0707 psi/ft
Casing Capacity:	0.04049 bbl/ft
Tubing Capacity:	0.00829 bbl/ft
Tubing closed-end displacement:	0.01190 bbl/ft
Pump displacement:	0.0899 bbl/stroke

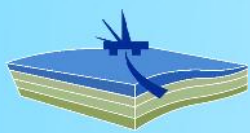
Calculate how many strokes are required to displace the tubing string volume?

Answer: _____ strokes

11. What is the meaning of Formation FRACTURE Pressure?

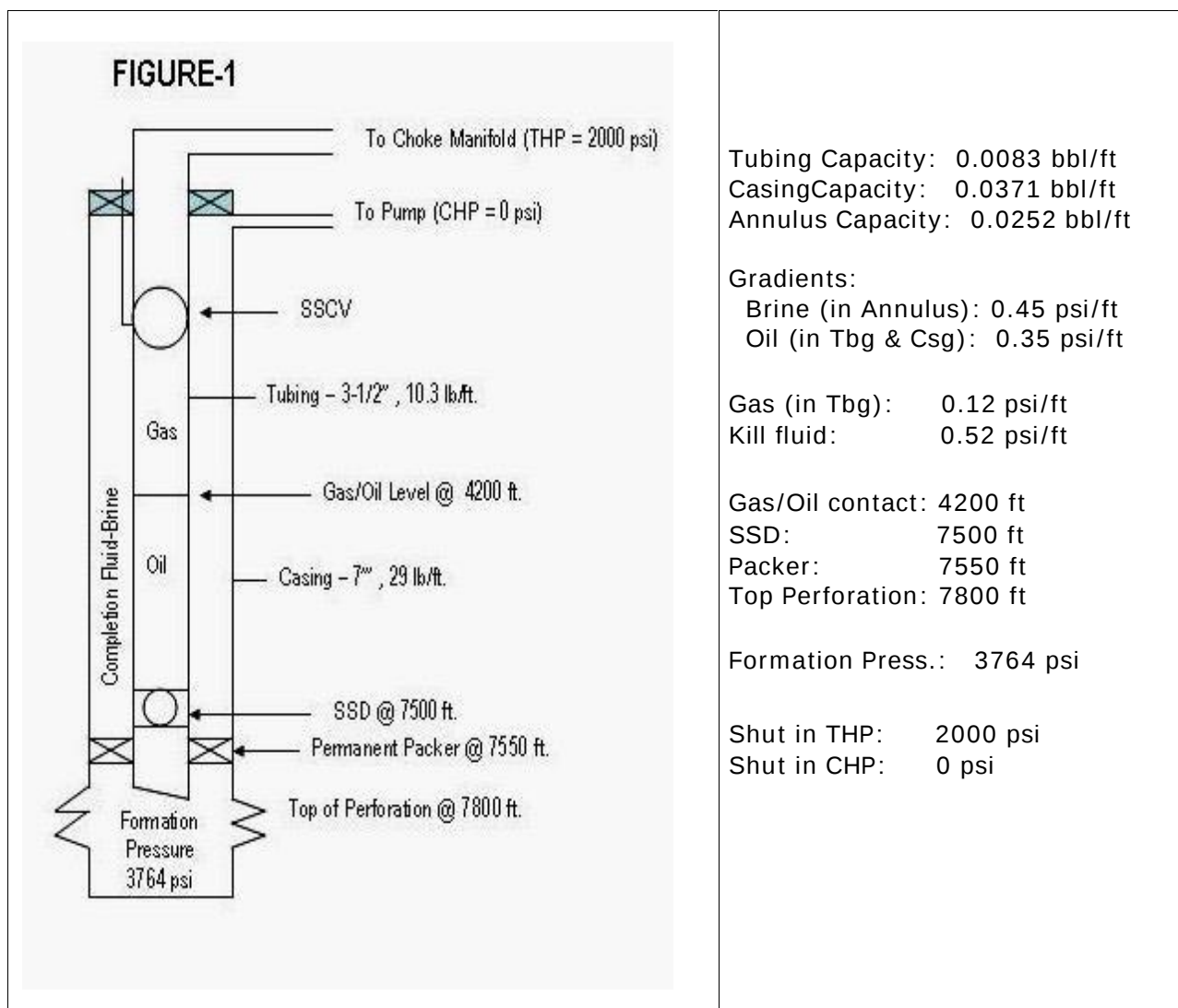
12. What is the meaning of Formation BREAKDOWN Pressure?





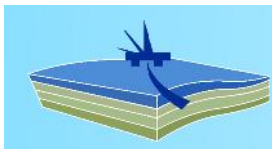
13. If the well program does not include a signed approval from a designated and authorized person, what action to take prior to commencing a job?

Figure 1 below shows the configuration of a well which is shut in and will be killed by REVERSE CIRCULATION method. See next page for further details.



- The Tubing has a constant ID/OD and contains gas and oil.
- The Casing below the Packer is filled with oil.
- The Annulus is filled up with completion brine.





The kill fluid is to be pumped through annulus via the Sliding Sleeve until formation fluid, gas and brine completion fluid are displaced out entirely.

During this killing operation, an overbalance of 200 psi above the formation pressure at top of the tubing side is to be maintained.

Use information given above to calculate and answer the question 14 - 19.

NOTE: Round off your values to a whole number, i.e. no decimals

14. Calculate tubing volume used for this operation _____ bbls
15. Calculate annular volume used for this operation _____ bbls
16. Calculate downhole pressure in a static condition at the Sliding Sleeve [SSD] of the following periods during reverse circulation well killing.
 - a) Expected pressure to be maintained constant at SSD during entire kill operation (include overbalance): _____ psi
 - b) When tubing is full of completion brine (include overbalance): _____ psi
 - c) When reverse circulation was completed [without overbalance]: _____ psi
17. After pumping 63 bbls, the tubing head pressure is maintained constant at 200 psi until 189 bbls have been pumped. What is the reason for maintaining a constant pressure at 200 psi over this interval?

Answer: _____

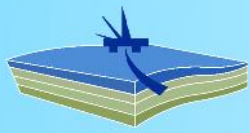
18. While pumping between 63 bbls until 189 bbls, if tubing head pressure is held constant at 150 psi instead of 200 psi, will the well become under-balanced?

Answer: _____ (Yes or No)

19. How many barrels of kill fluid must be pumped to fill the annulus to the point where gas has just been displaced out of the tubing string?

Answer: _____ bbls





20. During a well intervention operation, an emergency situation arises and it becomes necessary to kill the well. Which killing method is the most appropriate to be used if the formation interval is exposed [perforated] and the maximum surface working pressure is high enough to handle the pressures for this method?

Answer: _____

21. If the recommended method in your answer to question 20 is not possible, what is the second best method that should be used?

Answer: _____

22. Given data: -

Tubing depth:	9,500 ft MD and 8,750 ft TVD
Tubing capacity:	0.0025 bbl/ft
Annular capacity:	0.0052 bbl/ft
Pump rate:	0.75 bbls/min

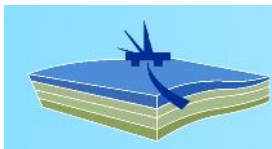
Calculate the time required to pump full circulation.

Answer: _____ minutes

23. What are the possible consequences when attempting to open a closed valve while there is pressure on one side only? (TWO ANSWERS)

- a) It can cause the valve itself to become damaged
- b) It will reduce the risk of damage to the valve
- c) It will reduce chance of pressure locking the valve
- d) It can cause less hydraulic shock to the system
- e) It can cause equipment downstream of the valve to become damaged





EXERCISE COMPLETION OPERATIONS 2

1. Given is Data for a Producing Gas Well: -

Well Depth:	12,000 ft (MD) and 6,150 ft (TVD)
Tubing Shoe Depth (EOT):	11,500 ft (MD) and 5,980 ft (TVD)
Formation Pressure Gradient:	0.5720 psi/ft
Gas Gradient:	0.0707 psi/ft
Casing Capacity:	0.0452 bbl/ft
Tubing Capacity:	0.0083 bbl/ft
Tubing Closed-End Displacement:	0.0120 bbl/ft
Pump output:	0.0899 bbl/stroke

How many pump strokes are required to displace the entire well bore, by pumping down tubing?

Answer_____strokes

2. Given is Data for a Producing Gas Well: -

Well Depth:	11,200 ft (MD) and 9,570 ft (TVD)
Formation Pressure Gradient:	0.5720 psi/ft
Gas Gradient:	0.0707 psi/ft

The 7" casing has been set and the 3-1/2" completion string installed. Prior to perforating, the drilling mud in the well has to be displaced with brine to balance formation pressure.

- 2.1 What is the required brine density?

Answer_____ppg

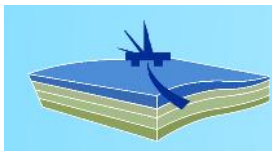
- 2.2 What is the rated working pressure (WP) of wellhead and Xmas tree equipment to be installed on this well?

Answer_____psi

3. A well has to be killed with brine weight of 9.0 ppg. The well depth is 12,000 ft (MD) or 10,500 ft (TVD). The recently measured formation pressure is 4,814 psi. How much is the 'overbalanced' pressure?

Answer_____psi





4. Which of the following are commonly used as barriers, when we are able to monitor and maintain the fluid level? (THREE ANSWERS)

- a) Brine
- b) Nitrogen
- c) Diesel
- d) Condensate
- e) Drilling mud
- f) Inhibited Sea Water

5. Which barrier terminology (Primary, Secondary or Tertiary) is used to classify Water, IF this water is pumped into the well, stabilizes the well pressure and there is no flow to surface?

Answer _____

6. The well has just been shut in on a gas kick. What is the expected behavior of this gas influx at the bottom of the well? [FOUR ANSWERS]

- a) Gas will migrate upwards as a result of its lower density compared with other fluids in the well
- b) The surface shut-in pressure will decrease with time after the well is shut in
- c) The surface shut-in pressure will increase with time after the well is shut in
- d) The bottom hole pressure will increase with time after the well is shut in
- e) The bottom hole pressure will decrease with time after the well is shut in
- f) The gas influx bubble pressure will remain the same

7. When planning a kill on a standard 'single completion' well, which killing method is always preferred?

Answer _____

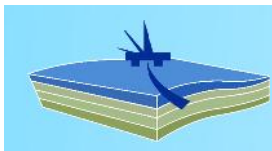
8. Which of the following measures or actions can prevent or remove hydrates? (THREE ANSWERS)

- a) Rapid bleed-off of gas to a vent or flare system
- b) Use of water/glycol mixture during pressure testing
- c) Pressure testing up to the maximum working pressure of the equipment
- d) Raising the temperature of the affected equipment
- e) Injecting methanol into the affected equipment

9. Can a fluid barrier be a Secondary Barrier?

- a) YES
- b) NO





10. Which of the following statements describe an effective kick-off or toolbox meeting?

- a) Get everyone involved to attend the meeting and explain exactly what is going to happen during the operation
- b) Get everyone involved to attend the meeting and go through plans, ask for feedback and comments, modify the plan if necessary and make sure that everyone understands it properly
- c) Get everyone involved to attend the meeting and read out the plan sent out by the onshore organization. Explain that the plan must be followed to the letter

11. If a problem occurs during an intervention operation, who should shut in the well and be responsible for safe working practices? (TWO ANSWERS)

- a) The Operator Representative (or Well Foreman)
- b) The Well Intervention planner
- c) The person who is designated to operate a control panel
- d) The Production Manager
- e) The leader of the Well Intervention team
- f) The operator of on-site Well Intervention equipment

12. Can hydrate ONLY be formed with free water in the well?

- a) YES
- b) NO

13. Hydrates may cause damage to Well Intervention Equipment if they are released as a result of high differential pressure!

- a) TRUE
- b) FALSE

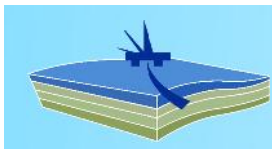
14. Which of the following mechanical devices can be installed by Well Intervention methods and is accepted to function as a barrier? (TWO ANSWERS)

- a) Hi-vis pill
- b) Casing Cement Retainer
- c) Pump Open plug
- d) Orifice valve
- e) Expandable Plug

15. A rod pumping well will be re-completed. Does the well need to have the same minimum number of well control barriers in place when compared with a well that has natural flow?

- a) NO
- b) YES





EXERCISE COMPLETION OPERATIONS 3

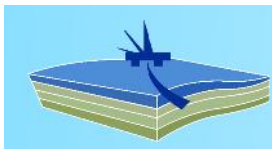
1. How to record a pressure gauge reading during pressure testing? (TWO ANSWERS)
 - a) Check the pressure gauge at the start and the end of the test
 - b) Frequently monitor the pressure gauges during the test
 - c) If there is no visible leak during test period, then its OK
 - d) Pressure recorder (stylus), is normally required to verify the test

2. Which of the following statements is correct if a completion well is planned to be killed by bull heading?
 - a) The kill pump & surface lines must be designed to resist the pressure equal to the maximum anticipated SIWHP
 - b) The kill pump & surface lines must be designed to resist the pressure equal to the maximum anticipated reservoir pressure
 - c) The kill pump & surface lines must be designed to resist the pressure equal to the maximum anticipated SIWHP plus a margin for friction
 - d) The kill pump & surface lines must be designed to resist the pressure equal to the maximum reservoir fracture pressure

3. What are benefits of holding pre-job meeting prior performing well control operations? (THREE ANSWERS)
 - a) To get to know each other
 - b) To agree in logistics
 - c) To discuss well control incident in details
 - d) To promote forward planning
 - e) To know roles and responsibilities of the individuals

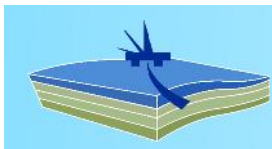
4. What are reasons for using clear brine as a completion fluid in the completion well? (TWO ANSWERS)
 - a) To ensure we have compatibility with the formation and formation fluids
 - b) To ensure we have hydrostatic pressure that is able to contain well pressure
 - c) To avoid formation debris settling above packer
 - d) To isolate pressure from the inner annulus and the completion tubing
 - e) To contain well pressure in case of packer or casing leaks





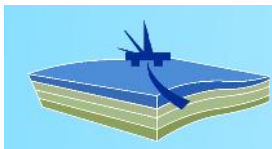
5. A live production well has sands and scales in the casing below several hundred feet of perforations. There is one low pressure loss (thief) zone. A work string is run inside the completion. Which of the following statements are true? (TWO ANSWERS)
- a) To stop the losses, it may be necessary to use a fluid with Loss Circulation Material [LCM], such as salt sized particles
 - b) The circulation system will need to allow pumping down the work string and the tubing to work string annulus must have sufficient flow to overcome losses
 - c) Reverse circulation is the best option with a thief zone in the well
 - d) A high pump rate will be required to overcome the thief zone
 - e) The thief zone may limit circulation rate that is necessary to obtain flow to surface
6. Which of the following statements best describes the principle of Lubricate and Bleed?
- a) Create a gradually rising overbalance with increasingly heavier fluid
 - b) Bleed off gas from tubing or annulus and after each bled off stage pump kill fluid down to compensate for the resultant decrease of hydrostatic head
 - c) Maintain constant circulation of heavy fluid down the annulus or tubing
 - d) Pump kill fluid down tubing or annulus in calculated volume steps and after each step bleed off gas to compensate for the resultant increase of hydrostatic head
7. Which of the following criteria determine the ability to bullhead? (TWO ANSWERS)
- a) The permeability of the formation
 - b) The position of the Blind Rams
 - c) The type of completion or tool string in the hole
 - d) The collapse pressure of the completion or tool string
 - e) The rated working pressure of the surface equipment
8. A closed gate valve has a pressure of 3,500 psi below and 0 psi above. Which of the following statements are true? (TWO ANSWERS)
- a) All gate valves are designed to open with pressure on one side only
 - b) High differential pressure assists a gate valve to opening more efficiently
 - c) A sudden pressure surge can damage other equipment downstream of the valve
 - d) Equalizing puppet in the gate valve ensures pressure is equalized across the gate valve as it opens
 - e) The mechanical force required to turn the handle can damage the valve stem





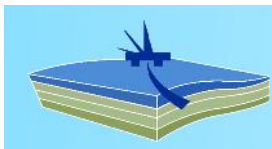
9. When shutting in the well at the Xmas tree, which of the following statements are true? (THREE ANSWERS)
- a) Upper Master Valve is normally used if there is nothing in the hole
 - b) Lower Master Valve is not normally used
 - c) Swab Valve shuts off all flow from the well
 - d) Upper Master Valve will seal around the wire
 - e) Damage to the valve can occur if it would be closed on tool strings
10. During slickline operations with the tool string at 1,000 ft, hydrate has formed at the Stuffing Box. What is the most likely reason for this to occur?
- a) No particular reason, because it is a well-known issue when running wireline
 - b) The Stuffing Box is leaking
 - c) We have residual water from pressure tests that has reached the Stuffing Box
 - d) The atmospheric [ambient] temperature is low
11. If the well head pressure is 150 psi, can we then use only one barrier when performing well intervention activities?
- a) Yes
 - b) No
12. After a well handover from production to well service operation an accident occurred during a well intervention activity. Who will take full responsibility?
- a) Production Supervisor
 - b) Well Intervention Supervisor
 - c) Both Production and Well Intervention Supervisor
13. The well was shut in on the BOP during a workover, and after for a while, the surface shut in pressure gradually increases. What are possible causes? (TWO ANSWERS)
- a) Gas migration
 - b) Production from an adjacent well
 - c) Injection from an adjacent well
 - d) There is an additional kick in the well bore





14. Which of the following statements is correct regarding Maximum Allowable Surface Pressure (MASP)? (TWO ANSWERS)
- a) It is the same for all wells in the same location
 - b) It has to be re-calculated if we encounter a change, e.g. corrosion
 - c) There is no need for re-calculation
 - d) It remains the same throughout the life of the well
 - e) During the life of the well, it will have to be regularly re-evaluated
15. During a work over operation it is known that the fluid hydrostatic pressure is just balancing formation pressure. A small amount of gas is swabbed in and the well shut in. The recorded shut in pressure is 0 psi. Then the gas is allowed to migrate but without expansion. Which of the following statements are correct when the gas bubble continues to migrate to surface? (THREE ANSWERS)
- a) The Gas Bubble Pressure will be half of Formation Pressure
 - b) The Gas Bubble Pressure remains the same but BHP will be approx. double
 - c) Gas Bubble Pressure will be the same as Bottom Hole Pressure
 - d) Surface Shut-in Pressure will be half of Bottom Hole Pressure
 - e) Surface Shut-in Pressure will be same as Gas Bubble Pressure
 - f) There is not enough information to determine the pressures





EXERCISE COMPLETION OPERATIONS 4

1. Which of the following mechanical barriers can be installed by well intervention?
(TWO ANSWERS)
 - a) Float Valve [for cementing]
 - b) Differential Valve [for production]
 - c) Dump Valve
 - d) Wireline Plug
 - e) Pump Through Plug

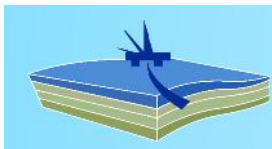
2. To perform a well intervention operation safely, what type of document should be available in which we can find the recommended tasks and precautions to be performed and the responsibilities of personnel on the location or installation?
 - a) Contingency Manual
 - b) Joint Operations Manual
 - c) Regulator HandBook
 - d) Well Interventiona Manual
 - e) Well Control Manual

3. How does a mechanical barrier prevent well flow?
 - a) By closing off the well path
 - b) By closing a Xmas Tree Valve
 - c) By pumping through the Kill Wing
 - d) By creating a small overbalance over well pressure

4. The production well has to be killed by bull heading and this is done before any well intervention operation is taking place. Which of the following can limit the maximum allowable surface pressure? (THREE ANSWERS)
 - a) The existing shut-in WHP
 - b) The burst limit of tubing
 - c) The downhole safety valve operating pressure
 - d) The ID of the tubing string
 - e) The maximum pump speed
 - f) The RATED working pressure of surface equipment
 - g) The fracture or breakdown pressure of the formation

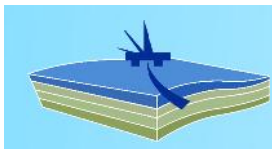
5. While doing well intervention operation, various groups of barriers may be used to control well pressure. What is the common terminology of each barrier group?
 - a) 1st, 2nd and 3rd Generation
 - b) First line, Second line and Third line
 - c) Primary, Secondary and Tertiary
 - d) 1st Class, 2nd Class and 3rd Class





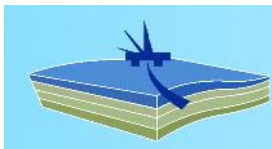
6. Bottom hole pressure is 3,800 psi. Maximum Surface Pressure is 3,050 psi. Select the correct working pressure for well head equipment to be installed.
- a) 3,000 psi
 - b) 5,000 psi
 - c) 2,000 psi
7. Which statements are true regarding Xmas Tree Valves during well intervention operations? (THREE ANSWERS)
- a) The Lower Master Valve is normally not in use
 - b) The Upper Master Valve will seal around wireline
 - c) Valves can get damaged if they are closed on a tool string
 - d) The Upper Master Valve is normally used if there is nothing in the well
 - e) The Kill Wing Valve is normally used as Surface Safety Valve [SSV]
8. A flowing production well is being shut in at Xmas tree. The SITHP quickly builds up to 2,000 psi. During next three hours the SITHP slowly climbs up to 2,350 psi. What is the most likely cause of increment in SITHP?
- a) Gas cap developing
 - b) It is normal. All wells seem to be like that
 - c) Perforation zones are plugged off
 - d) DHSV may be stuck in a closed position
9. When doing the well intervention operation, an emergency situation arises. It becomes evident that the well must be killed first before we can fix the problem. Which method would you prefer if the perforation zone is opened?
- a) Volumetric Method
 - b) Bullheading Method
 - c) Forward Circulation Method
 - d) Wait and Weight Method
 - e) Concurrent Method
 - f) Lubricate and Bleed Method
10. Which killing method is time consuming compared with others and is often applied prior to any well intervention operation?
- a) Volumetric Method
 - b) Bullheading Method
 - c) Forward Circulation Method
 - d) Wait and Weight Method
 - e) Concurrent Method
 - f) Lubricate and Bleed Method





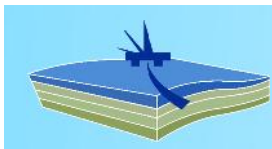
11. It is not possible to perform an inflow test on the installed plug. Should it be pressure tested?
- a) No
 - b) Yes
12. Injecting brine into the flow stream can reduce the formation of hydrates. True or false?
- a) True
 - b) False
13. In an emergency situation, and if it is not possible to bullhead the well, what is the most suitable and/or the most appropriate method to kill the well?
- a) Volumetric Method
 - b) Concurrent Method
 - c) Weight and Weight Method
 - d) Lubricate and Bleed Method
 - e) Reverse Circulation Method
 - f) Forward Circulation Method
14. Which of the following element is a 'Closable' barrier?
- a) Tubing Hanger Plug
 - b) Production Packer
 - c) BOPs & Xmas tree valves
 - d) Pump-Out Plug
 - e) Check Valve
15. Hydrates are most likely formed at downstream of the chokes. True or false?
- a) True
 - b) False
16. From which direction should a barrier be tested to verify integrity?
- a) Above
 - b) Below
 - c) Direction of flow
 - d) Both ways
17. Can a dead well be inflow tested?
- a) Yes
 - b) No





18. When the hydrostatic pressure of fluid in the well overbalances the formation pressure (without fracturing the formation), it becomes a Primary Barrier. True or false?
- a) True
 - b) False
19. When well control equipment has to be repaired, who is in charge for re-certification and final approval before using it again for well service operations?
- a) Chief Operator
 - b) Production Manager
 - c) Offshore Installation Manager (OIM)
 - d) Completion and Well Services Supervisor (CWI)
 - e) Original Equipment Manufacturer (OEM)
20. During completion well service operations, who is in charge for providing clear procedures, written agreements, responsible for well control duty and to act as a stand-in for supervising well service operations?
- a) Chief Operator
 - b) Production Manager
 - c) Offshore Installation Manager (OIM)
 - d) Completion and Well Services Supervisor (CWI)
 - e) Original Equipment Manufacturer (OEM)
21. A Xmas tree is to be changed out on a production well. A deep set positive plug has been set at the tailpipe below packer. A second plug is to be set in the tubing hanger before the tree can be removed. After confirming that the bottom plug is set, what is the correct action to take before setting the second barrier in the tubing hanger?
- a) Apply pressure on the annulus to test the deep set positive plug from below
 - b) Apply pressure on the tubing to test the deep set positive plug
 - c) Inflow test the deep set positive plug
 - d) If the well head pressure is not rising, the second plug can be run immediately
22. After shutting in the well at the Xmas tree, the tubing head pressure increases rapidly, then increases slowly with about the same rate. What is the main reason for this to happen?
- a) There is an additional influx in the well
 - b) There is gas migration
 - c) It is a pressure build up from the reservoir
 - d) It is because we're bullheading back into the formation





23. What is the best description of the Formation Breakdown Pressure?

- a) The maximum surface pressure, which will break down the formation at the casing shoe (drilling well)
- b) The maximum pressure that is applied in a well before any fracture/rupture takes place of the exposed formation

24. The principle of the Lubricate and Bleed Method can be defined?

- a) First pumping kill fluid into the well and then bleeding off gas thereafter.
- b) Pumping kill fluid into the well and bleeding off gas simultaneously.

25. Is the following statement TRUE or FALSE?

- a) Hydrates can only be formed if there is a free water in the well fluid content (TRUE or FALSE) _____
- b) Hydrate can be formed if there is only free water in the well fluid content (TRUE or FALSE) _____

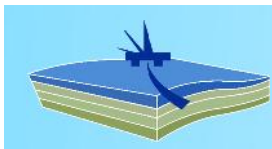
26. Which testing method for pressure control equipment (PCE) is acceptable and in agreement with the integrity of pressure control principles?

- a) Perform all testing before installation on the wellhead or Xmas Tree
- b) Perform all testing at a shore location before shipping it to offshore facilities
- c) No need to test because all PCE are tested at manufacturing facilities before use
- d) All PCE should be tested on the well head after installing and prior to operations

27. Any well control accident taking place during well intervention operations, and which is a result of not following sound well control procedures, can have various negative impacts. Which of the following are examples of these negative impacts (FOUR ANSWERS)?

- a) Financial loss
- b) More opportunities to get promoted
- c) Equipment damage
- d) Better maintained equipment
- e) Additional government regulations
- f) Better trained personnel
- g) Effect on environment
- h) More opportunities to gain experience





28. What is an advantage of the Reverse Circulation Kill Method?

- a) It creates lower surface pressures at all times
- b) It creates lower downhole pressure at all times
- c) It created lower friction pressure for the same pump rate
- d) It helps to clean up the deep-set plug in the tail pipe of the completion

29. Why do we need train personnel in well control? (THREE ANSWERS)

- a) So they can earn more money
- b) So they know what to do in case of emergency
- c) So they can have faster promotion
- d) So colleagues can rely on them
- e) So the shift handover can be done more efficiently
- f) So the client well can be drilled without any kick at all

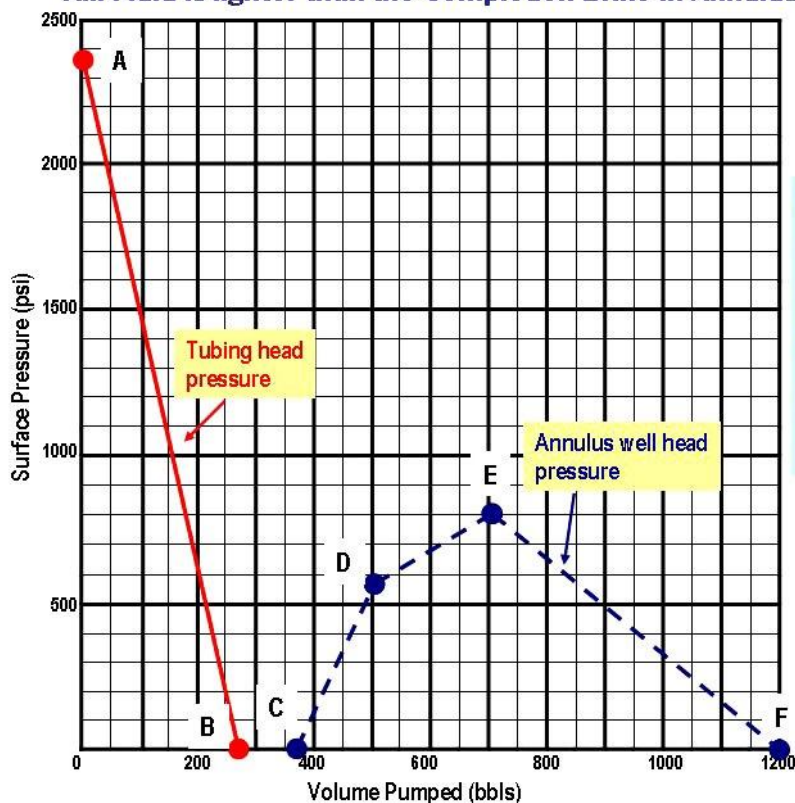




EXERCISE WELL KILL OPERATIONS 5

Reverse Circulation #1 [Static Condition]

Kill Fluid is lighter than the Completion Brine in Annulus



More Information:-

- Point A, pressure = 2,367 psi
- Point B, barrels pumped = 273 bbls
- Point C, barrels pumped = 389 bbls
- Point D, pressure = 571 psi
- Point D, barrels pumped = 500 bbls
- Point E, pressure = 800 psi
- Point E, barrels pumped = 700 bbls



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Referring to the reverse circulation graph and the information above, answer the following five (5) questions

1. What is the total volume of the well?

Answer _____ bbls

2. What is the tubing pressure at the start of the pumping operation?

Answer _____ psi

3. What is an approximately tubing pressure after pumping 200 barrels of lighter fluid into annulus?

Answer _____ psi

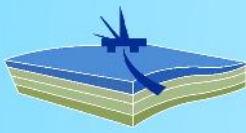
4. What is the annulus well head pressure after pumping 200 barrels of lighter fluid into into annulus?

Answer _____ psi

5. At what point on the graph does the new lighter fluid completely fill in the annulus and the original completion brine completely fill in the tubing?

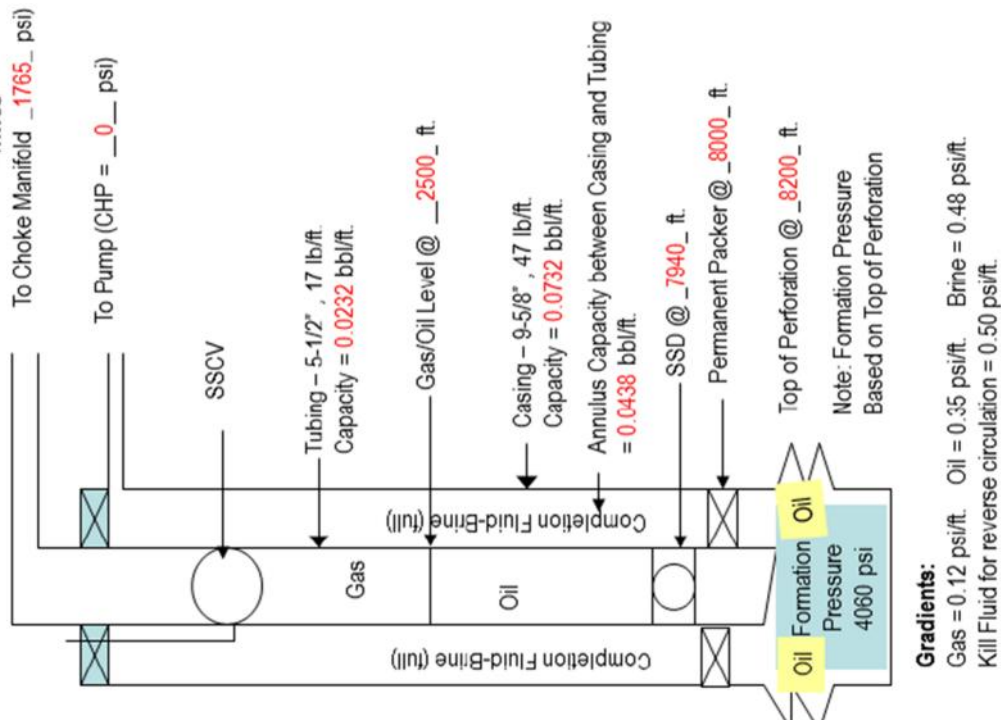
Answer _____ [Point]





Reverse Circulation #2

COMPLETION DIAGRAM -1

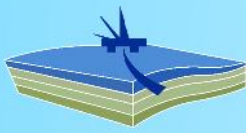


From Completion Diagram, Calculate and

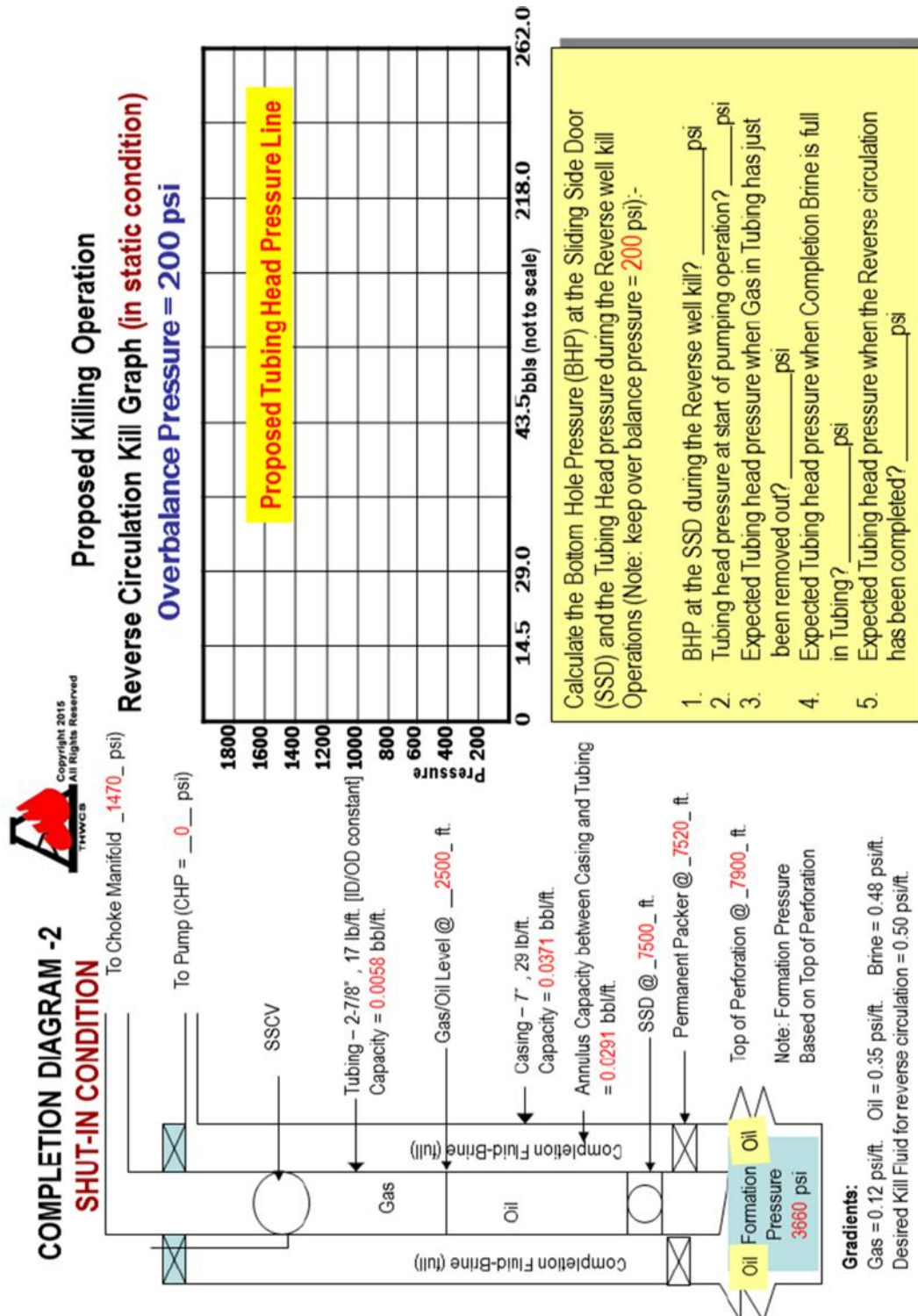
Answer the following questions:

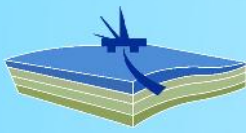
All questions related to REVERSE Circulation
(in static condition)

1. What is the volume in Annulus? _____ bbls
2. What is the volume of Gas in Tubing? _____ bbls
3. What is the volume of Oil in Tubing from Gas contact until SSD? _____ bbls
4. How many barrels of kill fluid to be pumped in annulus when the Gas has been completely displaced out of the tubing? _____ bbls
5. How many barrels to pump and Kill fluid starts entering the tubing? _____ bbls
6. When tubing has just been completely filled with Brine, calculate the pressure at the SSD in static condition. The THP at that time was **158** psi. _____ psi



Reverse Circulation #3





Reverse Circulation #4

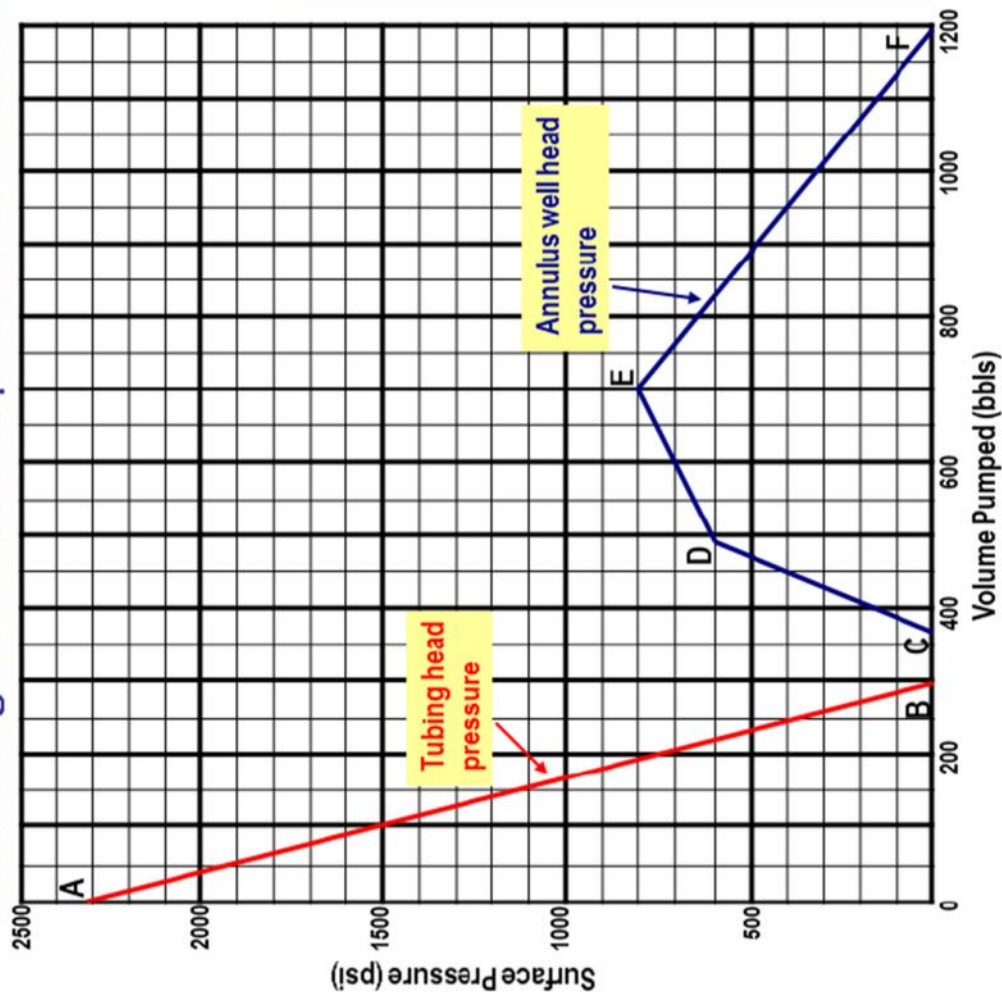
Kill Graph for Reverse Circulation For initiative Production.

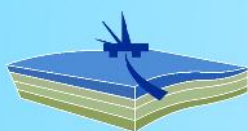
- Tubing & Annulus capacity are constant
- The Tubing consists of Gas and Oil (Gas above, Oil below)
- In Annulus filled with a heavy Brine
- Light fluid density is less than Brine density

1. What is the total volume of this well for Reverse circulation?
2. What is the Tubing head pressure at the start of the pumping operation?
3. What is the Tubing head pressure after pumping 100 bbls of Kill fluid?
4. What is the Annulus well head pressure After pumping 200 bbls of Kill fluid?
5. At what point on the graph does the lighter Fluid completely fill the annulus and the Original completion fluid (Brine) completely fill the Tubing?



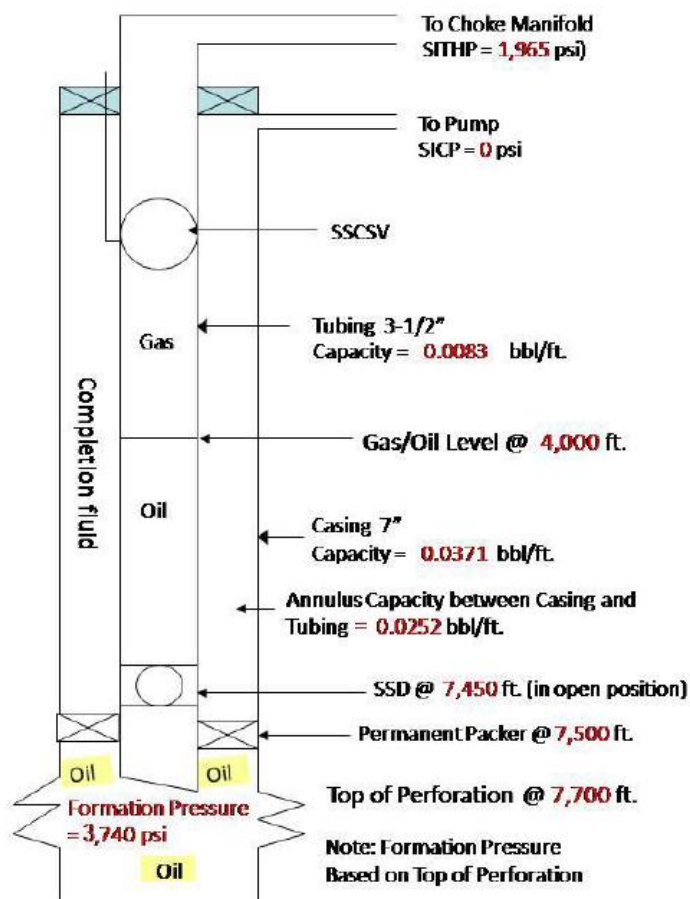
Reverse Circulation Kill Graph (in static condition)
Kill Fluid is lighter than the Completion Brine in Annulus





Reverse Circulation #5

COMPLETION DIAGRAM



Gradients:

Gas = 0.12 psi/ft. Oil = 0.35 psi/ft. Brine = 0.49 psi/ft.

Kill Fluid for reverse circulation = 0.52 psi/ft.

Over Balance Pressure apply during reverse circulation = 200 psi

STIHP = 1,965 psi

Tubing Capacity = 0.0083 bbl/ft

Casing Capacity = 0.0371 bbl/ft

Annular Capacity = 0.0252 bbl/ft

Gas/Oil Contact = 4,000 ft.

Gas in Tubing, gradient = 0.12 psi/ft

Oil in Tubing and in Casing,
Gradient = 0.35 psi/ft

Brine in Annulus as a completion
fluid, gradient = 0.49 psi/ft

Kill fluid, gradient = 0.52 psi/ft

SSD depth = 7,450 ft (TVD)

Packer Depth = 7,500 ft. (TVD)

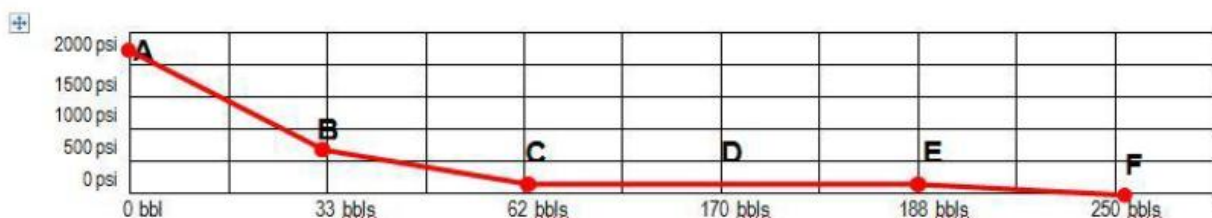
Top of Perforation = 7,700 ft. (TVD)

Formation pressure = 3,740 psi

Reference at Top of perforation

During reverse circulation;

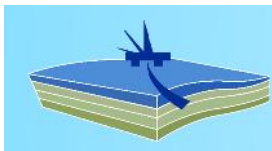
Over balance pressure = 200 psi



Pressure Schedule (tubing head pressure only)

Point A	Point B	Point C	Point D	Point E	Point F
2,165 psi	685 psi	200 psi	200 psi	200 psi	-22

Use this information, calculate and answer the following five (5) questions;



Reverse Circulation #5 - Questions

1. What is the bottom hole pressure (BHP) at the sliding side door (SSD) during reverse circulation well kill?

Answer: _____psi

2. After 62 barrels of kill fluid has been pumped, the tubing head pressure has stabilized at 200 psi (point C), the pressure remains unchanged until we have pumped 188 barrels (point E). What is the reason for stabilization at 200 psi?
 - a) The level of fluid in tubing has dropped to below surface
 - b) The gas coming out of the well, therefore, no longer expanding
 - c) The tubing remains filled with original completion brine and hydrostatic head remains unchanged
 - d) The oil is coming out the well and the choke opening remains unchanged

3. What is the total volume in annulus between well head and sliding sleeve (SSD)?

Answer: _____barrels

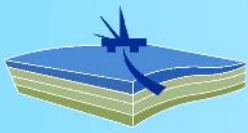
4. If the tubing head pressure between point [C] and point [E] is held constant at 150 psi, instead of 200 psi, will the well be under balance?

Answer: _____

5. At what point on the graph does the kill fluid partly filled in annulus while the gas has just been displaced out of the tubing string?

Answer: Point _____



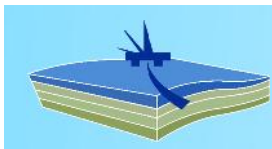


PTS

IWCF Well Intervention
Well Control WORKBOOK

LEVEL 3/4





END-OF-COURSE PAPER COMPLETION OPERATIONS 6

1. Which are correct definitions for Formation Pressure and of Fracture or Breakdown Pressure?

TWO ANSWERS

- a. Formation Pressure is the pressure exerted by fluid or gas in a formation
- b. Fracture Pressure is the pressure exerted by a static column of fluid
- c. Fracture Pressure is the pressure at which formation starts to break down
- d. Formation Pressure is the pressure at which the formation will breakdown
- e. Fracture Pressure is the surface pressure at which formation starts to break down
- f. Formation Pressure is equal to the surface pressure when the well is just closed in
- g. Formation Pressure is the pressure recorded at surface with the well producing

2. Before starting with a reverse circulation job, the following information is available:-

Depth of Circulation Point:	11,555 ft MD and 9,986 ft TVD
Casing Capacity:	0.0745 bbls/ft
Tubing Capacity:	0.0385 bbls/ft
Casing/Tubing Capacity:	0.0255 bbls/ft
Pump Output:	2.8 bbls/min

- 2a. Calculate the time required for 'bottoms up'

Answer: _____ min

- 2b. Calculate the time required for a 'full' circulation

Answer: _____ min

3. Before starting with a reverse circulation job, the following information is available:-

Depth of Sliding Sleeve:	9,825 ft MD and 9,638 ft TVD
Gas Gradient:	0.12 psi/ft
Packer Fluid Density:	9.6 ppg
Shut-In THP:	4000 psi
Shut-In CHP:	0 psi

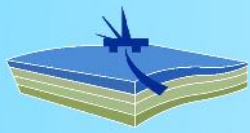
- 3a. What is the differential pressure at the Sliding Sleeve

Answer: _____ psi

- 3b. Which side [Tubing or Annulus] must be pressured up before safely opening the Sliding Sleeve?

Answer: _____





4. We are about to start a forward circulation. The following information is available: -

End of the Tubing:	8,847 ft MD and 7,629 ft TVD
Casing Capacity:	0.0486 bbls/ft
Tubing Capacity:	0.0106 bbls/ft
Tubing Metal Displacement:	0.0040 bbls/ft
Pump Output:	0.26 bbls/stroke

- 4a. How many pumps strokes are required to circulate the tubing string?

Answer: _____ strokes

- 4b. How many pumps strokes are required to circulate tubing and annulus?

Answer: _____ strokes

5. We are observing a gas well for pressures. The following information is available: -

Top of Reservoir:	11,756 ft MD and 9,882 ft TVD
Formation Pressure Gradient:	0.68 psi/ft
Gas Gradient:	0.095 psi/ft

- 5a. Calculate the Kill Fluid Density

Answer: _____ ppg

- 5b. Calculate the Shut-In Tubing Pressure

Answer: _____ psi

- 5b. Calculate the Shut-In Bottom Hole Pressure

Answer: _____ psi

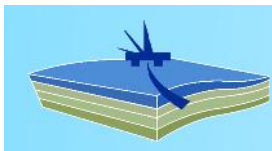
6. We are observing a gas well for pressures. The following information is available: -

Depth of Well:	9,444 ft MD and 8,666 ft TVD
Gas Gradient:	0.096 psi/ft
Packer Fluid Density:	11.2 ppg
Packer Depth:	9,180 ft MD and 8,408 ft TVD
Shut-In Tubing Pressure:	3500 psi

What is the differential pressure between tubing and annulus below the Tubing Hanger?

- a. 590 psi greater in the annulus than the tubing
- b. 590 psi greater in the tubing than the annulus
- c. 3500 psi greater in the annulus than the tubing
- d. 3500 psi greater in the tubing than the annulus
- e. 2910 psi greater in the annulus than the tubing
- f. 2910 psi greater in the tubing than the annulus
- g. There is no differential pressure





7. Following a handover of a production well from the Production Supervisor to the Well Intervention Team, a Well Intervention job is in progress. During a E-line Production Logging Test [PLT], a leak is observed at the Production Choke, which is part of the Production Manifold.

Who is considered responsible for managing this well control situation?

- a) The Well Intervention Supervisor
- b) The Well Intervention Equipment Operator
- c) The Production Operations Supervisor
- d) Both the Production Operations Supervisor and Well Intervention Supervisor
- e) Fracture column of fluid

8. Which of the following conditions are considered essential for Well Intervention work to be conducted safely?

THREE ANSWERS

- a) Using the Xmas Tree as the Primary Barrier at all times
- b) Using inspected, tested and well maintained equipment
- c) Having a pre-job meeting with all parties involved before starting any job
- d) Having a Well Intervention Supervisor present on the job at all times
- e) Performing frequent drills, so that the crews know what to do in case of a well control incident
- f) Calling the Well Intervention Supervisor to shut in the well when the crew is facing a well control incident

9. What is the primary purpose of a MoC [Management of Change] system?

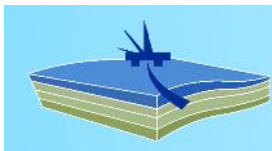
TWO ANSWERS

- a) To reduce the cost to as low as practically possible
- b) To make the Well Intervention service providers responsible for avoidable risks
- c) To reduce the number of changes that can be made to procedures or equipment
- d) To ensure that a proposed change is part of the risk control protocol
- e) To evaluate the risks associated with the proposed change, such as to avoid unintended consequences

10. What is the primary reason for conducting a risk assessment?

- a) To have a fall back option in case an activity is threaten to fail
- b) To identify potential consequences and likelihood of an equipment or a procedural failure, such that appropriate controls can be put in place to prevent or mitigate an incident from happening
- c) To supplement a work permit, so that workers do not get injured or sick when performing the activity
- d) To ensure that crew members and supervisors involved in an activity are fully aware of their responsibilities and will have the correct behaviours to perform an activity safely and efficiently





11. Why is it considered important for workers to be properly trained in well control procedures and using well control equipment in accordance with global and regulatory acceptable standards?

THREE ANSWERS

- a) To have effective daily, bi-weekly or monthly shift handovers
- b) To prevent well control incidents and uncontrolled pressure releases
- c) To facilitate fast and effective promotion through the ranks
- d) To ensure that companies can rely on their work force, because it provides them with the tools of what to do in case of a well control incident
- e) To make it more attractive for workers in terms of salaries and bonuses paid
- f) To ensure that workers will respond swiftly and appropriately when faced with a well control incident

12. During a wireline activity we experience a leak at the Xmas Tree Adaptor Flange connection. The well has to be shut in as soon as possible. However, we suspect that the tool string may still be across the Xmas Tree. What should we do now?

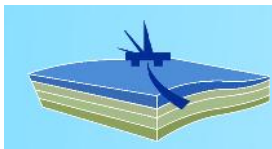
- a) Close the Shear/Seal BOP on top of the Xmas Tree. It will cut the tool string and this will drop below the Xmas Tree valves
- b) Close the hydraulically activated Upper Master Gate Valve, which will have enough force to shear the tool string
- c) Use the Lower Master Gate Valve, because this the designated emergency valve for these situations
- d) Close the Swab Valve, slowly, and by counting the turns, so that an obstruction can be detected and to avoid any damage to valve gate, tool string or wireline. Stop closing and back off the valve upon any detection of resistance!

13. We are in the process of running sand screens as part of a gravelpack assembly. What equipment should be available?

TWO ANSWERS

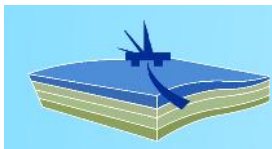
- a) A set of Pipe Rams, which allows a good fit around the sand screen joints. These can be installed quickly may the need arise
- b) A blank joint with the same OD as the Pipe Rams already in the BOP. This joint should have a crossover and Full Opening Safety Valve installed on top of it.
- c) A Blind/Shear Rams capable of shearing the sand screens
- d) A crossover and Full Opening Safety Valve that can be installed on top of any of the sand screen joints in case of a well control incident





14. A producing well was shut in. The Tubing Head Pressure first increased sharply, then gradually. Over the hours that followed, the pressure continued to rise at a slow but steady rate. What is the most likely cause of this pressure behavior?
- a) A gas cap is developing. Over time, gas is slowly separating from the oil and then migrating up the well
 - b) The reservoir pressure is still flowing slowly into the wellbore. For that reason, the shut-in surface pressure has not stabilized as yet either
 - c) The oil is separating slowly from the water and because oil has a lighter density than water, the surface pressure will continue to go up
15. With the wireline tool string at 900 ft, we observe that hydrates are starting to form at the stuffing box. What is the most likely reason?
- a) An environment with cold temperatures
 - b) A residue of water that remains in the lubricator after a pressure test
 - c) A gas leak at the stuffing box
 - d) All of the above
 - e) None of the above
16. A completion with a permanent packer is being run to just above the perforated zone. We intend to displace the brine in the well to inhibited seawater, by using forward circulation.
- | | |
|---------------------------------|------------------------------|
| Top of Perforated Interval: | 8,840 ft MD and 7,630 ft TVD |
| Bottom of Perforated Interval: | 8,880 ft MD and 7,660 ft TVD |
| End of Tubing: | 8,800 ft MD and 7,600 ft TVD |
| Casing Capacity: | 0.07240 bbls/ft |
| Tubing Capacity: | 0.00817 bbls/ft |
| Closed-End Tubing Displacement: | 0.01190 bbls/ft |
- Before we set the packer, how many barrels of inhibited seawater will have to be pumped to ensure we can use this seawater as packer fluid?
- Answer: _____ bbls
17. We are testing the Swab Valve on a live well and it fails the original pressure test at 110% of the rated work pressure. Would it be necessary to replace this valve?
- a) If it would still pass the maximum anticipated surface pressure, then it would be acceptable to use this valve, no need to replace it
 - b) The Swab Valve should be removed, then visually inspected and if necessary, worn parts redressed. Then re-installed, and pressure tested to the maximum anticipated surface pressure
 - c) Yes, the valve should be replaced with another certified valve, and then pressure tested to 110% of the rated work pressure as per original plan.





18. Wireline has been used to install a deep-set plug in the tailpipe of the completion string in anticipation of Xmas Tree removal. Given the high pressures in this well, we intend to perform an inflow test. In order to determine the differential pressure across the plug, which of the following considerations should be made?

TWO ANSWERS

- a) Down Hole Safety Valve Collapse Pressure
- b) Casing Burst Pressure
- c) Casing Collapse Pressure
- d) Tubing Burst Pressure
- e) Tubing Collapse Pressure
- f) Xmas Tree Pressure Rating

19. How many barriers are recommended to be in place, according to API?

- a) One active barrier and a procedure to ensure its integrity
- b) In all cases, a primary, a secondary and a tertiary barrier
- c) At least one active and tested barrier
- d) A minimum of two tested and available barriers
- e) Two active barriers

20. Can a T-Gate Valve be a primary barrier?

- a) Yes
- b) No

21. When performing a pressure test to verify a barrier, who is responsible for the sign-off and acceptance of this barrier?

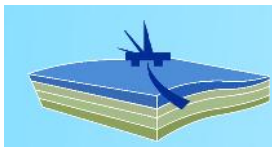
- a) The Well Intervention Company Representative
- b) The Well Intervention Service Company Supervisor
- c) The Production Supervisor
- d) The Equipment Supervisor or Representative

22. We are opening a gate valve with pressure on one side only. Which of the following statements is correct?

TWO ANSWERS

- a) The differential pressure across the gate valve will assist in opening it
- b) Damage can be caused to the stem and to gate/seat sealing surfaces
- c) Damage can be caused to equipment downstream of the gate valve
- d) The risk of a pressure lock across the gate valve will be reduced





23. Below is a diagram with a number of barrier elements for a production well. The well is shut in so that we can safely rig up for Well Intervention activities. The TR-SSV remains in an open position.

23a. Identify the active barrier elements from the list below, that are part of the primary barrier envelope

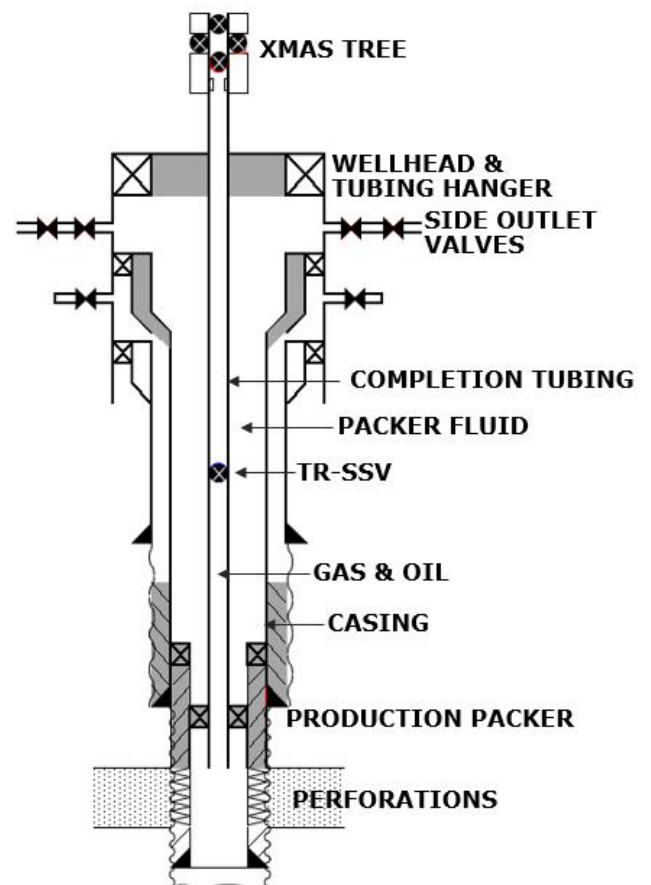
Answer: _____

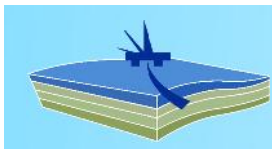
23b. We found out that there is a leak in the tubing below the TR-SSV. Identify the active barrier elements from the list below, that are now becoming active and are therefore part of the secondary barrier envelope. The TR-SSV is now in a closed position.

Answer: _____

Barrier Elements:-

- a) Xmas Tree
- b) Wellhead/Seals & Tubing Hanger
- c) Wellhead Side Outlet Valves
- d) Tubing above TR-SSV
- e) TR-SSV
- f) Tubing below TR-SSV
- g) Completion Fluid
- h) Casing above Production Packer
- i) Liner/Cement above Prod. Packer
- j) Production Packer
- k) Liner/Cement below Production Packer





24. Which of the following fluids or gases are the most commonly used to function as a barrier?

THREE ANSWERS

- a) Nitrogen
- b) Drilling Mud
- c) Seawater
- d) Condensate
- e) Diesel
- f) Brine

25. Which components would need to be tested before we can safely rig up any Well Intervention equipment?

- a) The Production Packer
- b) The Xmas Tree valves
- c) The Annulus
- d) The Tubing string

26. We are not able to perform an inflow test on a positive plug in the tubing. Should we instead perform a pressure test from above?

- a) Yes
- b) No

27. Which of the following checks should be made before and after we have run a wireline plug in the tubing?

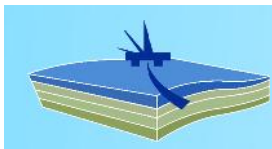
THREE ANSWERS

- a) Check that pressure is equalized before installing the plug
- b) Check that the plug holds pressure after it has been installed
- c) Check the the pressure rating is correct
- d) Check that the plug is installed as close as possible to the Xmas Tree
- e) Check that a contingency plan is in place in case solids settle on top of the plug

28. What do we mean with 'performing an inflow test'?

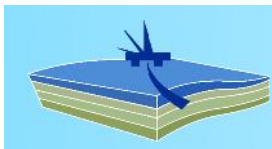
- a) To apply pressure below an installed barrier
- b) To equalize pressure across an installed barrier
- c) To apply pressure above an installed barrier
- d) To bleed off pressure or reduce hydrostatic head above an installed barrier





29. A well is incapable of natural flow. How many well control barriers need to be in place before we can perform a workover?
- a) One
 - b) Two
 - c) Three
 - d) Sometimes one and sometimes two
30. What is the function of a 'positive' plug?
- a) It prevents flow from above
 - b) It prevents flow from below
 - c) It prevents flow from above and below
31. Which of the following are 'closable barriers'?
- TWO ANSWERS
- a) The Blowout Preventer
 - b) The Production Packer
 - c) The BPV in the Tubing Hanger
 - d) The Positive Plug set in the Nipple of the Tail Pipe
32. We are performing a workover on a well with open perforations. Which of the following 'barrier classifications' apply to the workover fluid we use?
- a) Primary
 - b) Secondary
 - c) Tertiary
33. There are two 'types' of barriers. What are these type of barriers generally called?
- TWO ANSWERS
- a) Elastomer type of barrier
 - b) Mechanical type of barrier
 - c) Upper barrier
 - d) Lower barrier
 - e) Fluid type of barrier
 - f) Positive barrier
 - g) Negative barrier





34. As part of the lower completion, we are running sand screens and slotted pipe. Which of the following equipment must be included to allow the crew to safely shut in the well?

TWO ANSWERS

- a) A standard rig-up of Pipe Rams and Annular Preventer is adequate and no additional equipment is necessary
- b) Shear Rams able to cut sand screens and slotted pipe
- c) A blank joint of pipe with crossover and Safety Valve installed on top, which can be run swiftly and on which we can close the Pipe Rams in use
- d) Blind/Shear Rams able to cut the sand screens and slotted pipe and seal the well thereafter
- e) Crossover able to fit sand screens and slotted pipe and a Safety Valve to be available on the rig floor

35. During bullheading, which factors may cause the Surface Pressure to become too high?

THREE ANSWERS

- a) Tubing Burst Pressure
- b) Kill Fluid Density
- c) Scale and deposits in the tubing
- d) Rated Working Pressure of surface equipment
- e) Maximum Surface Pressure that we can apply
- f) Tubing with a small Inside Diameter
- g) Formation Fracture Pressure
- h) High Shut-In Tubing Head Pressure [SITHP]

36. We intend to perform a bullhead kill on a well, which has a Xmas Tree rated to 5000 psi. However, the Shut-In Tubing Head Pressure is 4860 psi. Will it be practical to make an attempt to go ahead with the bullhead?

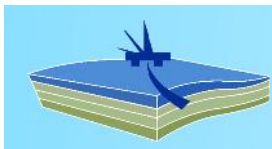
- a) Yes, the Shut-In Pressure is less than the rating of the Xmas Tree
- b) No, there is insufficient margin for injectivity and friction pressure losses between the SITHP and rating of the Xmas Tree
- c) Yes, there is always 10% allowed 'above' the rating of the Xmas Tree or other equipment in use

37. What are the important kill fluid properties to be considered when selecting a well kill fluid?

TWO ANSWERS

- a) Density
- b) Viscosity
- c) Gel Strength
- d) Additives that do not damage the formation or formation fluids





38. Which statement is true in describing how the Lubricate & Bleed well kill method is performed on a tubing string with a Shut-In Pressure?

- a) By pumping pre-determined volume of kill fluid and then after a short time, to bleed off gas to a pre-determined pressure to keep BHP constant
- b) By bleeding SITHP to zero, then circulate or fill up the tubing to kill fluid
- c) By filling or pumping the tubing string full with kill fluid, then bleeding off the Tubing Head Pressure
- d) By pumping kill fluid through the kill wing and bleeding gas of the flow wing at the same time

39. During bullheading, which factors will always limit the 'Maximum' Surface Pressure?
THREE ANSWERS

- a) Tubing Inside Diameter
- b) The Shut-In Wellhead Pressure
- c) Formation Fracture Pressure
- d) Maximum Pump Rate
- e) Rating of Surface Equipment
- f) Operating Pressure of the DHSV
- g) Burst Rating of the Tubing

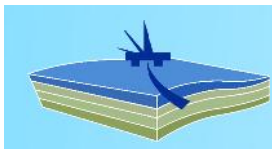
40. Which of the following statements are correct when it relates to 'hydrates'?
FOUR ANSWERS

- a) Hydrates will disappear at the same temperature under which they are formed
- b) Hydrates often occur downstream of a choke
- c) Hydrates can cause damage if they become dislodged
- d) The presence of free water is necessary for the formation of hydrates
- e) The temperature must be below 0 [zero] deg C before they can be formed
- f) Hydrates are less likely to form if we inject glycol
- g) Low pressure will increase the likelihood of hydrates forming

41. For a production well, which of the following are advantages using the reverse circulation to kill the well?
THREE ANSWERS

- a) It is always the fastest method that can be applied
- b) It never requires wireline intervention
- c) The Annulus Pressure remains low
- d) There is a low risk of formation damage
- e) The Annulus remains free of formation fluids





42. Which of the following factors determine whether we can or cannot perform a bullhead to kill a well that is being worked over?

TWO ANSWERS

- a) The injectivity rate of the formation in which we want to bullhead
- b) The rated working pressure of the surface equipment in use
- c) The collapse rating of the work string in use
- d) The availability of a Blind/Shear Ram BOP
- e) The outside diameter of the work string in use

43. In which of the following situations is bullheading the preferred method to kill a production well?

TWO ANSWERS

- a) In circumstances where speed to act is important
- b) In circumstances where there is a high risk of formation damage
- c) In a well with a damaged DHSV, which cannot be retrieved by wireline
- d) In a well with a stuck wireline plug in the upper completion

44. Which of the following factors are very important when selecting the pump rate in order to kill a production well?

TWO ANSWERS

- a) The ability to control pressures of the return flow by choke manipulation
- b) The frequency with which we must perform maintenance on the pumps
- c) The operational limitations of the surface separator equipment
- d) The time available to perform the kill operation

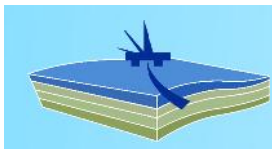
45. While performing wireline activity on a well we experience a leak at the Xmas Tree flange connection. The Well Intervention Supervisor decides to kill the well without further delay. Which of the following methods should be used?

- a) Volumetric Method
- b) Lubricate and Bleed Method
- c) Reverse Circulation Method
- d) Bullheading Method
- e) Forward Circulation Method

46. Which of the following methods are mostly used to prevent the forming of hydrates?

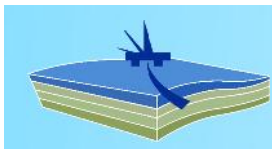
- a) Injecting methanol in places where hydrates are expected
- b) Increasing the temperature of the Xmas Tree
- c) Bleeding off gas rapidly
- d) Using a mixture of water and glycol during pressure testing
- e) Not performing pressure tests above a barrier that is closed or put in place
- f) Flaring off any gas that is bled off from the well





47. Which of the following methods are mostly used to remove hydrates?
- a) Injecting methanol in places where hydrates are expected
 - b) Increasing the temperature of the Xmas Tree
 - c) Bleeding off gas rapidly
 - d) Using a mixture of water and glycol during pressure testing
 - e) Not performing pressure tests above a barrier that is closed or put in place
 - f) Flaring off any gas that is bled off from the well
48. Before we are able to kill a production well, we intend to open the Sliding Sleeve. However, it seems that the sleeve is stuck in a closed position and we do not have any other circulation path in the completion string. Which of the following methods should be used instead, which will also prevent formation damage?
- a) Volumetric Method
 - b) Lubricate and Bleed Method
 - c) Bullheading Method
 - d) Forward Circulation Method
 - e) Engineers Method
49. We are performing a well kill during a workover operation. Which of the following statements is correct?
TWO ANSWERS
- a) Losses will always occur in the upper sections of a producing zone
 - b) Losses can occur in all zones of a producing reservoir
 - c) Losses will always occur in the lower sections of a producing zone
 - d) Losses can occur in one zone while another zone is producing
 - e) Losses can be prevented by keeping light fluid in the bottom of the well
50. Which of the following factors are important when selecting a brine as a kill fluid?
TWO ANSWERS
- a) To ensure that we have compatibility with the formation and formation fluids
 - b) To achieve a high kill pump rate
 - c) To achieve a low kill pump rate
 - d) To create a slight overbalance over the formation pressure
 - e) To reduce annulus pressure loss





51. On the following page is a well schematic and also a reverse circulation graph.

Answer the questions that follow [51a to 51e] !

The relevant well information is as follows:

Top of Perforated Interval:	9,000 ft MD/TVD
Formation Pressure Gradient:	0.480 psi/ft
Depth of Sliding Sleeve:	8,900 ft MD/TVD
Tubing Capacity:	0.0090 bbls/ft
Annulus Capacity:	0.0245 bbls/ft
Packer Fluid Gradient:	0.460 psi/ft
Oil Gradient:	0.350 psi/ft
Gas Gradient:	0.12 psi/ft
Oil to Gas Contact:	5,000 ft MD/TVD
Shut-In Well Head Pressure:	2320 psi
Kill Fluid Gradient:	0.485 psi/ft

An additional overbalance of 200 psi is held over the formation pressure at the Sliding Sleeve during the entire reverse circulation. Friction pressures and potential losses to the formation are to be ignored.

51a. At what point [A, B, C, D, E, F or G] has all of the gas just been circulated out?

Answer: _____

51b. What is the pressure at the Sliding Sleeve throughout the well kill?

Answer: _____ psi

51c. What is the Annular Volume from surface to Sliding Sleeve?

Answer: _____ bbls

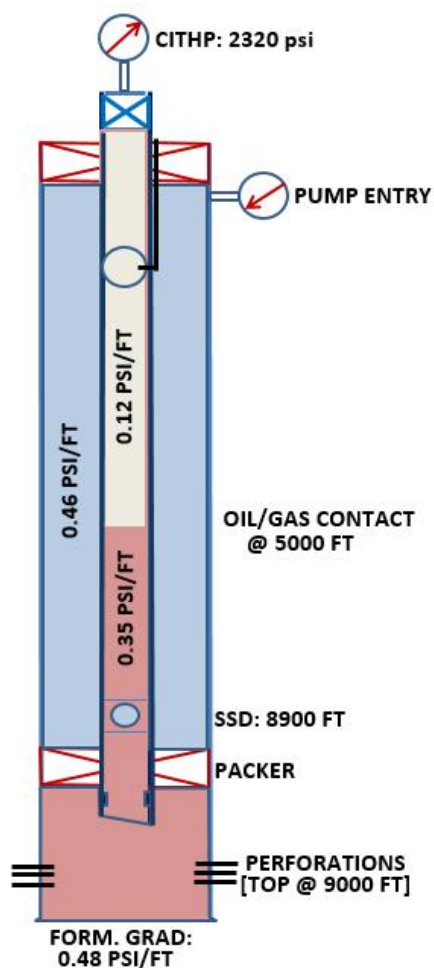
51d. If from point C to point E, the THP was kept 100 psi too low, which of the following statements would be correct?

- a) The well is still overbalanced
- b) The well is now in balance
- c) The well is now underbalanced

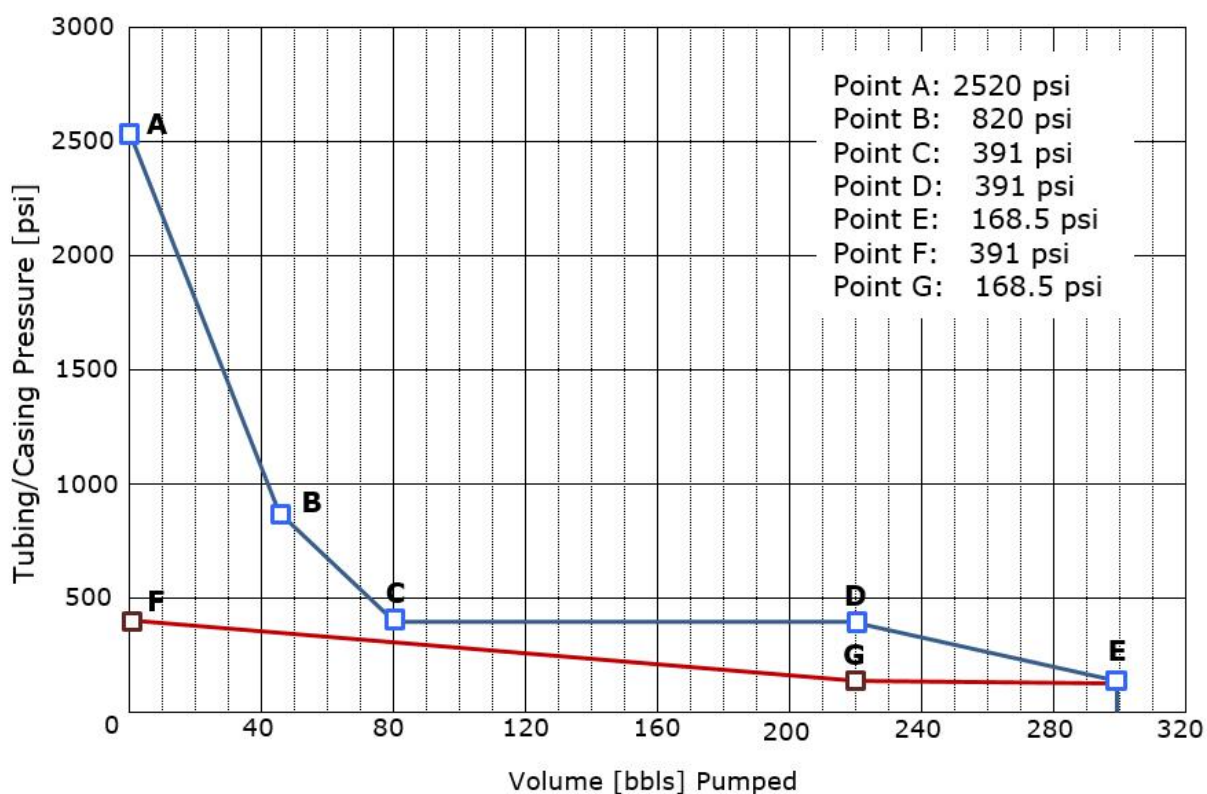
51e. After pumping 80.1 bbls, the Tubing Pressure stabilizes at 391 psi [point C]. This pressure remains constant until point D. What is the reason for this?

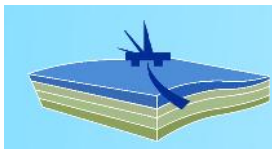
- a) The choke size remains unchanged while the oil is exiting the well
- b) The tubing stays filled with old packer fluid and therefore there is no change in the hydrostatic head of the tubing contents
- c) The gas is exiting the well and has stopped expanding any further
- d) The fluid level in the tubing has fallen





Top of Perforated Interval:	9,000 ft MD/TVD
Formation Pressure Gradient:	0.480 psi/ft
Depth of Sliding Sleeve:	8,900 ft MD/TVD
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Gas Gradient:	0.12 psi/ft
Oil to Gas Contact:	5,000 ft MD/TVD
Shut-In Well Head Pressure:	2320 psi
Kill Fluid Gradient:	0.485 psi/ft





52. You are planning to set a tubing plug in a nipple profile. What should be considered when you perform this job?

THREE ANSWERS

- a) Debris that may set on top of the tubing plug
- b) Pressure that the tubing plug will have to hold from below
- c) Shear crews of the locking dogs
- d) Pressure rating of the tubing plug
- e) Equalize the pressure before setting the tubing plug

53. Which of the following are the three (3) barriers that can be opened and closed?

- a) BOP, Surface-Controlled Sub-Surface Safety Valve, Xmas tree valve
- b) BOP, Cement Plug, Xmas Tree Valve
- c) BOP, Tubing Plug, Cemented Casing
- d) Retrievable Bridge Plug, BOP, Xmas Tree Valve

54. What is the function of a Landing Nipple positioned above the Production Packer?

- a) To enable setting of the Production Packer
- b) To enable setting of a junk catcher prior running SSD shifting tool
- c) To enable pressure testing completion components and tubing above the Production Packer
- d) To enable setting a downhole choke for production purposes
- e) To enable setting an orifice gas lift valve

55. What is the function of Landing Nipple positioned below the Production Packer?

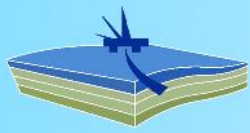
- a) To enable setting a junk catcher below the Production Packer prior shifting SSD
- b) To prevent a wireline tool from falling to the bottom of the completion string and into the liner sump
- c) To isolate the reservoir at the lowest point of the completion string
- d) To pressure test the completion string at any time while running the tubing

56. It is defined that 600 psi is the pressure margin that we have in the A annulus before compromising integrity of the well. From the given data below, how much can you reduce the fluid density in the tubing before reaching 600 psi pressure margin?

Packer setting depth 15,000 ft MD / 13,500 ft TVD

- a) 0.85 ppg
- b) 0.77 ppg
- c) 7.69 ppg
- d) 0.42 ppg





57. After you shut in a gas well, you noticed a rapid pressure increase, followed by a long and lasting pressure build up on the pressure gauge of the Xmas Tree. What are the most likely causes for this to happen?

TWO ANSWERS

- a) Gas migration
- b) Pressure build up from formation pressure
- c) Temperature drop
- d) Cross flow from a producing zone

58. What do we do when we apply a 'Lubricate and Bleed' well control method?

- a) Circulate kill fluid across the well and bleed off the gas that is liberated
- b) Gradually create an overbalance in the well by pumping kill fluid
- c) Pump a set volume of kill fluid into the well, then bleed off gas to compensate for gas being compressed and the additional hydrostatic head
- d) While bleeding off gas, pump a set volume of kill fluid into the well



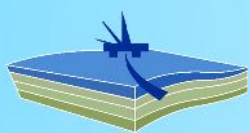


PTS

IWCF Well Intervention
Well Control WORKBOOK

LEVEL 3/4

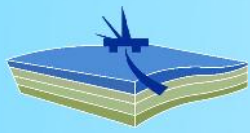




WORKBOOK COMPLETION OPERATIONS – ANSWER KEYS

EXERCISE COMPLETION OPERATIONS-1	
1.	10.0 ppg
2.	4427 psi
3.	2700 psi
4a.	3718 psi
4b.	3259 psi
4c.	5000 psi
5.	11.0 ppg
6a.	102 psi
6b.	Annulus
7.	100 psi
8.	3083 psi
9a.	66 minutes
9b.	97.5 minutes
10.	1015 strokes
11.	Formation FRACTURE pressure is the pressure that initiates the <u>first fractures</u> to which formation is exposed [such as formation across perfs].
12.	Formation BREAKDOWN pressure is the pressure that breaks down the formation and is higher than the fracture pressure. When we break down the formation, the fractures we initiated now rapidly extend radially. It has the risk of reducing the maximum allowable surface pressure on the well to be <u>lower</u> than the pressure applied when initiating first fractures.
13.	Suspend the operation [and usually means that we have to await further advice from the office-based Well Intervention Supervisor].
14.	63 bbls
15.	189 bbls
16a.	3859 psi [use formation pressure + 200 psi overbalance]
16b.	3859 psi [answer 'must' be the same as 16a]
16c.	3900 psi [kill brine creates overbalance of 241 psi]
17.	Tubing is now filled [and remains to be filled] with <u>completion brine</u> , so that the hydrostatic pressure over that interval pumped remains unchanged
18.	No
19.	35 bbls
20.	Bullheading
21.	Lubricate & Bleed
22.	98 minutes
23.	a, e





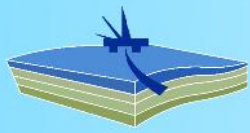
EXERCISE COMPLETION OPERATIONS-2

1.	5309 strokes
2.1	11.0 ppg
2.2	5000 psi
3.	100 psi
4.	a, e, f
5.	Primary
6.	a, c, d, f
7.	Reverse Circulation
8.	b, d, e
9.	No
10.	b
11.	c, f
12.	Yes
13.	a
14.	c, e
15.	Yes

EXERCISE COMPLETION OPERATIONS-3

1.	b, d
2.	c
3.	c, d, e
4.	a, e
5.	a, e
6.	d
7.	a, e
8.	c, e
9.	a, b, e
10.	b
11.	b
12.	b
13.	a, c
14.	b, e
15.	b, d, e

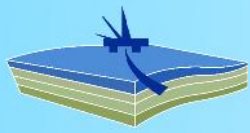




EXERCISE COMPLETION OPERATIONS-4

1.	d, e
2.	b
3.	a
4.	b, f, g
5.	c
6.	b
7.	a, c, d
8.	a
9.	b
10.	f
11.	b
12.	a
13.	d
14.	c
15.	a
16.	c
17.	b
18.	a
19.	e
20.	d
21.	c
22.	b
23.	a
24.	a
25a.	TRUE
25b.	FALSE
26.	d
27.	a, c, e, g
28.	a
29.	b, d, f





EXERCISE COMPLETION OPERATIONS-5

Reverse Circulation #1

- | | |
|----|---------------|
| 1. | 1200 bbls |
| 2. | 2367 psi |
| 3. | 600 – 650 psi |
| 4. | 0 psi |
| 5. | Point E |

Reverse Circulation #2

- | | |
|----|------------|
| 1. | 347.8 bbls |
| 2. | 58 bbls |
| 3. | 126.2 bbls |
| 4. | 58 bbls |
| 5. | 347.7 bbls |
| 6. | 3969.2 psi |

Reverse Circulation #3

- | | |
|----|----------|
| 1. | 3720 psi |
| 2. | 1670 psi |
| 3. | 770 psi |
| 4. | 120 psi |
| 5. | 0 psi |

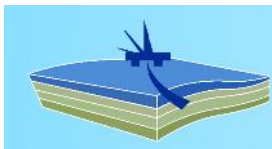
Reverse Circulation #4

- | | |
|----|-----------|
| 1. | 1200 bbls |
| 2. | ~2320 psi |
| 3. | 1500 psi |
| 4. | 0 psi |
| 5. | Point E |

Reverse Circulation #5

- | | |
|----|------------|
| 1. | 3852.5 psi |
| 2. | c |
| 3. | 188 bbls |
| 4. | No |
| 5. | Point B |





COMPLETION EQUIPMENT

EXERCISE COMPLETION EQUIPMENT 1

1. What are two most common types of Down-Hole Safety Valves [DHSVs] which are available for a well completion? (TWO ANSWERS)
 - a) Permanent
 - b) Tubing Retrievable
 - c) Temporary
 - d) Coiled Tubing Retrievable
 - e) Wireline Retrievable

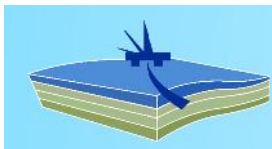
2. What are main functions of a Polished Bore Receptacle? (TWO ANSWERS)
 - a) It supports the weight of the completion tubing
 - b) It allows tubing to be pulled up from the packer
 - c) It compensates for contraction and/or elongation of tubing

3. When using a Polished Bore Receptacle and the tubing is not anchored, how is the tubing length affected when a well is started up for production?
 - a) The tubing string will become longer
 - b) The tubing string will become shorter

4. When using a Polished Bore Receptacle and the tubing is not anchored, how is the tubing length affected when a well is stimulated or started up for water injection?
 - a) The tubing string will become longer
 - b) The tubing string will become shorter

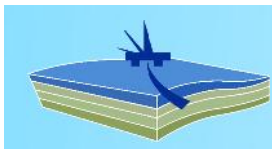
5. What are the main functions of a Tubing Hanger? [TWO ANSWERS]
 - a) It suspends the weight of the completion string
 - b) It allows communication from inside the tubing to the casing/tubing annulus through the control line ports
 - c) It isolates the completion from the casing/tubing annulus
 - d) It is the place where the well can be shut-in with control line pressure





6. What is the main purpose of Sliding Sleeve [SSD]?
 - a) To close off the tubing bore
 - b) To provide a communication path between the annulus and tubing and the other way around
 - c) To close off the annulus
7. Does a Down-Hole Safety Valve [DHSV] prevent the flow in both directions when it is closed?
 - a) No
 - b) Yes
8. When a Gas Lift Mandrel is installed, but not in use, what equipment must be installed to achieve a positive closure (i.e to prevent flow from both directions)?
 - a) Gate Valve
 - b) Chemical Injection Valve
 - c) Dummy Valve
 - d) Circulating Valve
 - e) Gas Lift Valve
9. Which of the following statements show the main purposes of having a Side Pocket Mandrel in the completion string? (TWO ANSWERS)
 - a) To provide a profile for landing some flow control devices
 - b) To provide a communication path between tubing and the casing annulus
 - c) To plug off the bore of the tubing
 - d) To act as a receptacle for gas lift, chemical injection, circulating or dummy valves
 - e) To act as a receptacle for a Wireline Retrievable DHSV
10. We want to use a surface controlled Wireline Retrievable DHSV. How do we establish hydraulic communication with the control line once the DHSV has been set and locked inside the Tubing Retrievable DHSV profile?
 - a) Through a hydraulic stab-in feature.
 - b) Between two packing seal stacks once the lock mandrel is set.
 - c) Through the SSD when the sleeve is opened.
11. Which of the following statements are true about Xmas tree? (TWO ANSWERS)
 - a) When we close the valves, it is necessary to close them as tightly as possible.
 - b) All valves on the Xmas Tree take 25 turns to open and close
 - c) After closing a manual valve, it should be backed out part of a turn.
 - d) Counting turns while operating the valve can indicate if there is an obstruction across the valve.
 - e) There is an indicator which shows how many turns remain to fully close the valve.





12. Which of the following statements are true with regards to the Circulating Devices in a well killing operation? (TWO ANSWERS)

- a) Check that the circulating device is fully opened
- b) Check that the catcher is installed below the SSD
- c) Check that the pressure rating is adequate for the job
- d) Check that the pressure is equalized before opening
- e) Check that the tail pipe plug is in place before opening the sleeve

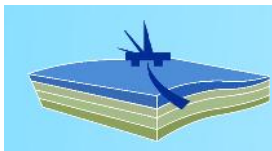
13. To prevent the formation fluids or gases from flowing, how are Down-Hole Safety Valve [DHSV] designed?

- a) To hold pressure from below
- b) To hold pressure from below and above
- c) To hold pressure from above

14. How can we set a Hydraulic Set Packer? (TWO ANSWERS)

- a) Apply pressure from the tubing side
- b) Apply pressure from the annulus side
- c) Set a positive plug below the packer





EXERCISE COMPLETION EQUIPMENT 2

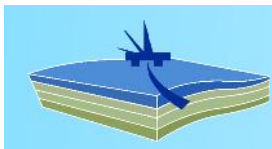
1. We are opening a closed gate valve, with one side having a pressure of 3,500 psi and the other side having no pressure [zero]. Which of the following are two (2) correct statements? [TWO ANSWERS]
 - a) Gate valves are designed to maintain pressure and to be opened with pressure on one side only.
 - b) High pressure differential across a gate valve can damage the equipment on the lower pressure side due to sudden surge effects.
 - c) The high differential pressure assists the gate to move easily when opening.
 - d) The mechanical force which is required to turn the valve handle can damage the valve itself, and especially the stem.
 - e) The equalizing poppet in the gate ensures that the pressure is equalized across the valve as soon as we start to open the valve.
2. The statement is made that, if an inflow test on a barrier is not possible, an Integrity Test can be performed by applying pressure from above.
 - a) TRUE
 - b) FALSE
3. How should we perform a test a closed Sliding Sleeve [SSD], if the annulus is filled with brine and the tubing is filled with diesel oil?
 - a) Flow the well so that we perform an inflow test
 - b) Bleed off the Shut-In Tubing Head Pressure [SITHP]
 - c) Pressure test the annulus side
 - d) Bleed off the annulus pressure
4. What is the primary advantage of a Wireline Retrievable Down-Hole Safety Valve?
 - a) Can be retrieved such as to allow intervention operations through the tubing.
 - b) Can be installed and retrieved with wireline.
5. Given data: -

Tubing capacity:	0.0055 bbl/ft
Casing capacity:	0.0381 bbl/ft
Annular capacity:	0.0293 bbl/ft
Tubing depth:	6,500 ft (TVD/MD)
Well/Casing Depth:	8,500 ft
Pump Output:	0.85 bbls/min

If we use forward circulation, calculate time in minutes required to pump from the bottom the annulus to the surface?

Answer: _____ Minutes





6. When does the column of fluid become an effective barrier?
- a) When the static BHP of this fluid column is equal to reservoir pressure
 - b) When the static BHP of this fluid column is less to reservoir pressure
 - c) When the static BHP of this fluid column is more to reservoir pressure
7. Why is it necessary to select an appropriate kill fluid to kill a well that is on production (TWO ANSWERS)?

- a) To avoid over excessive pressure on the formation
- b) To reduce potential annulus losses
- c) To maintain higher kill rate
- d) It enables us to select lower kill rate
- e) To ensure we have a fluid compatible with formation fluid and rock

8. The following data has been collected from a producing oil well: -

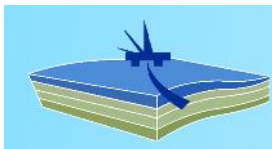
SITHP:	2,500 psi
SSD depth:	7,500 ft [TVD/MD]
Packer depth:	7,900 ft [TVD/MD]
Well/Casing depth:	9,000 ft [TVD/MD]
Top Perforations:	8,000 ft [TVD/MD]
Brine in Annulus:	0.48 psi/ft
Oil in Tubing:	0.36 psi/ft
Form. Press. at Top Perfs:	5,380 psi

What is the differential pressure between tubing and annulus at the underside of the tree/well head?

Answer: _____psi

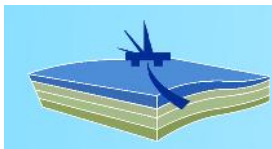
9. When a side pocket mandrel is being used for gas-lift or chemical injection, how are well fluids prevented from flowing into the production annulus?
- a) By means of a pressure differential across the gas lift mandrel
 - b) By means of a check valve in the gas lift mandrel
 - c) By means of a venture effect across the gas lift mandrel
10. When installing a BOP Stack with a rated WP of 10,000 psi onto a wellhead with a rated WP of 5,000 psi, which of the following statements is correct?
- a) The BOP Stack/wellhead combination permits a max. WP of 10,000 psi
 - b) The BOP Stack/wellhead combination permits a max. WP of 7,500 psi
 - c) The BOP Stack/wellhead combination permits a max. WP of 5,000 psi
 - d) The wellhead rating does not play any role, because only the BOP ensures that we have wellhead integrity on a live well





11. During a work over operation, and after retracting and unseating a retrievable packer, what procedure should be followed prior pulling the unseated packer to prevent potential swabbing?
 - a) Wait for about 1 minute to allow packer element to relax and retract, then start pulling out the completion string.
 - b) Set weight down on the packer to relax and retract the element, then start pulling out of hole
 - c) Unseat the packer by a straight pull, and slowly come out of the hole.
 - d) Wait for 1 hour or more to allow packer element to relax and retract, then start pulling out the completion string
12. During [body] testing of a 10,000 psi valve body, it has failed the test at 150% of its rated WP. Is it permitted to use this valve for a well operation with a maximum expected surface pressure of 7,000 psi?
 - a) Yes, because the applied test pressure is more than its expected working pressure
 - b) No, because the valve body test criteria remain to be 150% of its working pressure
13. When should testing of well control equipment, such as BOPs, be carried out prior using it?
 - a) Well control equipment should be tested every 21 days as per API Standard 53, regardless of testing performed in the workshop.
 - b) After the initial test in the workshop, we should test well control equipment once more after a component fails during scheduled operations.
 - c) There is no need to test well control equipment again, because it is always tested in the workshop prior transporting it to well site.
 - d) After installing well control equipment onto the wellhead and/or Xmas tree, it should be tested prior commencing any operation.
14. What are the main functions of a production packer? (TWO ANSWERS)
 - a) It isolates the annulus from the completion string
 - b) It allows anchoring of and sealing with the completion string
 - c) It allows suspension of the tubing string
 - d) It permits gas lifting on wells that can only produce by artificial lift
15. How often do we have to pressure test permanent barriers? (TWO ANSWERS)
 - a) Every year
 - b) Every 5 years
 - c) Before installation
 - d) After installation
 - e) When we detect a fault or leak, after we have performed a repair
 - f) Before and after installation





EXERCISE COMPLETION EQUIPMENT 3

1. A straddle packer is being run because we have a tubing leak. However, the straddle packer is not holding any pressure. What is the correct action to take?
 - a) Run another straddle packer above
 - b) Pull out and run a 'back-up' straddle packer
 - c) Kill the well by bull heading
 - d) Close the down hole safety valve

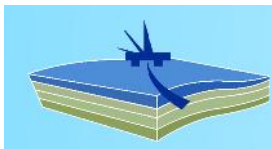
2. The Xmas tree has to be changed out. Which of the following is the correct sequence to ensure safe operations?
 - a) Kill the well – unseat packer – circulate – change tree
 - b) Set plug at the bottom tubing – pump killing fluid – set plug above – change tree
 - c) Set plug at the bottom – kill well by reverse circulation – set plug at tubing hanger – change tree

3. Which of the following is a correct definition of 'barrier' requirements in a completed well?
 - a) We must have a Primary, Secondary and Tertiary ENVELOPE
 - b) We must have at least 1 x primary and 1 x secondary BARRIER
 - c) We must have at least 2 independent barriers for any work activity
 - d) We must have a Primary, Secondary and Tertiary ELEMENT

4. You are pulling a retrievable packer with 40,000 lbs overpull and witness a surge in pressure, possibly from swabbing. How can this potential swabbing effect be reduced?
 - a) After unseating the packer, let it 'hang' for 1 hour or more without movement to allow packer element to relax and retract
 - b) Pick up & go down approximately 10 ft. before attempting to pull out of hole
 - c) Forward circulation around the packer to retract element before pulling
 - d) Run further into the hole as deep as possible before pulling

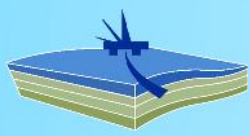
5. What are the main advantages of having production packers in well completions? (TWO ANSWERS)
 - a) It isolates the inner annulus [between casing & tubing] from the tubing string
 - b) It anchors the tubing string
 - c) It suspends the tubing string
 - d) It prevents well fluids and treatment fluids entering the outer annulus [between casing & formation or casing & casing]





6. The well is filled with 8.6 ppg. density fluid. The formation fracture gradient is 0.847 psi/ft and the well depth is 10,000 ft. (TVD). Calculate the Maximum Allowable Surface Pressure (MASP).
- a) 1,000 psi
 - b) 3,000 psi
 - c) 4,000 psi
 - d) 5,000 psi
7. When pressure testing a barrier, what should be avoided when the pressure test involves a deep positive plug?
- a) Do not allow differential pressure to exceed the string collapse pressure during bleeding off.
 - b) Do not allow different pressure to exceed the string burst pressure during bleeding off.
8. When run a completion string, how can we ensure that the tubing is made up correctly and then documented properly?
- a) By using a casing tong
 - b) By using the iron roughneck
 - c) By using a casing tong with computerized torque record
 - d) By using a rig tong and the rotary table
9. We plan to complete a well and run the completion tubing with a drilling rig. Which of the following statements are correct? (TWO ANSWERS)
- a) The cemented casing well bore with rig BOPs is sufficient for well barriers without using overbalance fluid.
 - b) The well must have a minimum of two barriers.
 - c) Tubing conveyed guns can not be run if there is no heavy mud.
 - d) All procedures must be followed in accordance with drilling and service contractor plans and the available equipment.
10. Where is the position of the seat in relation to a two-way check valve plunger?
- a) Above
 - b) Below
 - c) Above and below





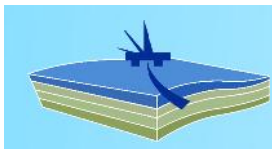
11. What type of closure mechanism can be fitted to the 'surface controlled' Wireline Retrievable Down-Hole Safety Valve? (TWO ANSWERS)

- a) Ball
- b) Flapper
- c) Orifice
- d) Gate

12. What type of closure mechanism that can be fitted to the TRSV?

- a) Ball
- b) Flapper
- c) Orifice
- d) Gate





EXERCISE COMPLETION EQUIPMENT 4

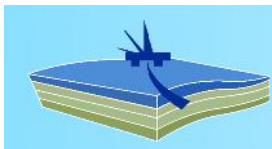
1. The BOP stack has rated working pressure of 5,000 psi. The well head pressure is 4,860 psi. The well is planned to be killed with the bullheading method. With the provided information above, is the BOP stack working pressure adequate for this operation?
 - a) The BOP stack is only OK with a 10% safety pressure margin
 - b) The BOP stack is OK, but bull heading should not be performed
 - c) The BOP stack is OK, because it has a 5,000 psi working pressure
 - d) The BOP stack working pressure is irrelevant

2. Why do we install Down Hole Safety Valves?
 - a) To close in the well to allow maintenance of topside equipment to take place.
 - b) To close in the well when production is to be shut down.
 - c) To close in the well in an emergency.
 - d) To control the rate of flow from the well.
 - e) To stop production if a topside valve is opened accidentally

3. Which barriers should be in place when completing a well and running the completion string? (THREE ANSWERS)
 - a) Overbalance fluid
 - b) Sliding Side Door
 - c) Rig BOP
 - d) SCSSSV
 - e) Casing

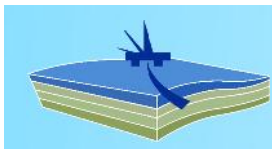
4. Which of the following should be mentioned in a barrier test verification document? (THREE ANSWERS)
 - a) The casing wall thickness
 - b) The kick off depth
 - c) The pressure rating of equipment
 - d) Official signature from authorized personnel
 - e) The deviation survey
 - f) The maximum BOP hydraulic pressure
 - g) The test fluid weight





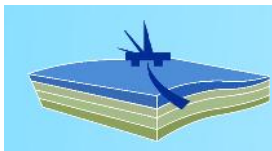
5. What statements are true regarding the Tubing Hanger? (TWO ANSWERS)
- a) It allows communication between completion string and annulus through control line ports
 - b) It supports the weight of the completion
 - c) It supports the weight of the completion and casing string.
 - d) It accommodates a Back Pressure Valve or Two-Way Check Valve
 - e) It allows communication with the completion string through control line ports.
6. What is a good practice when running a completion?
- a) To have a check valve fitted in the cement unit line, so that the well can be 'topped up' without fluids flowing back to the tanks.
 - b) When the TR-SSV is well below drilling BOP, the Pipe Rams can be closed on the tubing string to ensure we can maintain well control at all times
 - c) Ensure appropriate crossovers on the rig floor, so that a Drill Pipe Safety Valve can be made up to the completion regardless of size or type of thread being run
 - d) It will be easier to run the completion if there is no pressure in the TR-SSV control line. This makes it easier to monitor the displaced fluid flows with the TR-SSV run in closed position
7. To what barrier group does completion fluid belong if it can be checked, weighted up and monitored?
- a) Multiple Barrier
 - b) Tertiary Barrier
 - c) Secondary Barrier
 - d) Primary Barrier
8. What is the active barrier when running the Completion String?
- a) Casing
 - b) Over balanced fluid
 - c) Wellhead
 - d) Drilling Rig BOP
9. What are good practices when running a bridge plug with E-line? (TWO ANSWERS)
- a) The shear stud will weaken or part if there is too high an impact or too much pulling force generated on the releasing tool and the packer
 - b) The running speed should be restricted to ensure the bridge plug will not expand on the way down.
 - c) The running speed should be as high as practically possible to avoid pressure build up while running in the hole.
 - d) We must ensure that the pulling tool is appropriate for the bridge plug.





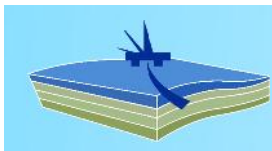
10. Can a Tee-Gate Valve be a primary barrier?
- a) No
 - b) Yes
11. If a Deep-Set Downhole Plug does not hold pressure, what action can be taken? (TWO ANSWERS)
- a) Retrieve the failed plug and replace with a new one
 - b) Place cement on top of the plug
 - c) Set another plug on top of the failed one
 - d) Mill out the plug
12. Who will approve the final outcome of any barrier testing on location?
- a) Production Manager
 - b) Well Service Supervisor
 - c) Chief Engineer in charge
 - d) Production Superintendent
13. How to keep the TR-SSV in an open position whilst running the completion? (TWO ANSWERS)
- a) By applying pressure on the control line
 - b) By using brine pressure in the casing annulus
 - c) By using the Lock Open Tool or Prong
 - d) By using a Hold Open Tool or Straddle Sleeve
14. How many types and/or methods are available to equalize pressure above and below the DSV allowing the DHSV to be opened?
- a) Two types, Non Equalizing and Self Equalizing
 - b) Two types, Non Equalizing and Self-Equalizing plus one method, Intervention
 - c) Two types, Non Equalizing and Self-Equalizing and two methods, Intervention and Bullheading
15. How can mechanical plugs be installed in the well? (TWO ANSWERS)
- a) By well intervention operations
 - b) By hydraulic pressure from the control line
 - c) By well velocity across the plug
 - d) By the freeze method
16. Can a Xmas Tree Valve be a primary barrier?
- a) Yes
 - b) No





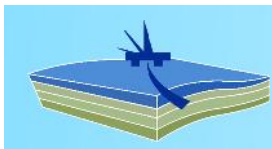
17. What is/are the first action[s] to take to re-instate production in a well with a failed Tubing Retrievable Down-Hole Safety Valve?
- a) Perform work over operations
 - b) Lock the valve mechanism open
 - c) Lock the valve mechanism open and install a wireline insert valve
18. Which type of Down-Hole Safety Valves are sub-surface controlled? (TWO ANSWERS)
- a) Flapper Valve
 - b) Differential Pressure Valve
 - c) Ball Valve
 - d) Wireline Retrievable Valves
 - e) Ambient Pressure Valve
19. How do we run the surface controlled Wireline Retrievable DHSV in an open position in the well?
- a) With a Lock-Open Sleeve
 - b) By applying hydraulic pressure to keep it locked open
 - c) With an automatic "J-slot" device
 - d) With a Prong on the Lock Mandrel Running Tool
20. If the SSD could not be opened, what would you do next to ensure communication can be established?
- a) Unseat the Production Packer
 - b) Connect the tubing and 'A' annulus at surface instead
 - c) Make 1 or more holes in the tubing with a tubing punch
 - d) Retrieve the Wireline Retrievable Down Hole Safety Valve
21. Which one of the following statements is correct regarding a barrier element?
- a) A barrier element is the same as a barrier envelope
 - b) A barrier element is the same as what we call primary barrier
 - c) A barrier element is the same as what we call secondary barrier
 - d) A barrier element is part of a series of barriers which together form a barrier envelope
22. What is the main cause that results in the surface-controlled DHSV to be closing?
- a) A significant drop in annulus pressure
 - b) A significant rise in annulus pressure
 - c) A significant rise in well pressure
 - d) A significant drop in tubing head pressure
 - e) A small drop in hydraulic control line pressure
 - f) A small rise in hydraulic control line pressure





23. While cementing a production casing, severe losses have been observed. What would be a good practice to perform after this cement job?
- a) Abandon well
 - b) Run 'cement bond log' to check for any potential poorly cemented interval
 - c) It okay because the casing itself has high integrity
 - d) Drill out cement shoe and set another casing inside
24. A tubing string will be run into the well during completion operation. What are correct practices? (TWO ANSWERS)
- a) Since drilling BOP is in place and the well has not been perforated yet, there is no need to kill the well first
 - b) Need a cross over sub to stab the FOSV to whatever completion string connections
 - c) We will use a string 'closed end displacement' to monitor trip tank volume
 - d) We will use a string 'open end displacement' to monitor trip tank volume
25. Which of the following are reasons to monitor annulus pressure at all times? (TWO ANSWERS)
- a) To ensure we are able to control the DHSV function.
 - b) To ensure we will be able to maintain barrier integrity status.
 - c) To check for any leaks of completion string, production packer, casing or wellhead seals
 - d) To check for the forming of hydrates below surface.
26. Which of the following are the most likely reasons for Annulus Pressure Build-Up? (TWO ANSWERS)
- a) The heating up of produced fluids inside the tubing, when starting up the production of a well.
 - b) A leak across the production packer, completion tubing connection or any [other] completion component
 - c) A leaking BPV or TWCV in the Tubing Hanger.
 - d) The gas cap effect after stopping the production for a long period of time.
27. An Annulus Pressure on a producing well is monitored and from one day to another observed to be much higher than expectation. What should now be done and for what reason?
- a) Nothing should be done. Pressures usually fluctuate because of day and night temperature changes.
 - b) This requires a well intervention in order to run a downhole memory gauge which measures changes in reservoir pressure.
 - c) The Annulus Pressure should be kept below a pre-determined maximum pressure, so that we do not have a risk of losing barrier containment.
 - d) The well should be closed in immediately. We may have cross flow across multiple zones from which we produce.





END-OF-COURSE PAPER COMPLETION EQUIPMENT 5

1. Which of the following statements are true about Permanent Packers?
TWO ANSWERS
 - a) Can be released and retrieved together with the completion string
 - b) Can only be pushed down or retrieved by milling or other destructive means
 - c) May be retrieved with a special pulling tool on a work string, after milling the top slips of the packer
 - d) Can be converted into a Retrievable Packer by inserting a prong

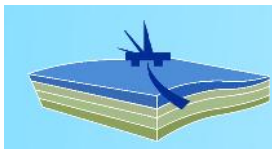
2. What is the primary barrier when running a completion string in a well that has open hole formation or open perforations?
 - a) The Casing and good quality cement around it
 - b) The Production Packer
 - c) The Fluid Hydrostatic Head, provided fluid to surface and of correct density
 - d) The Sub-Surface Downhole Safety Valve
 - e) The BOP Stack

3. Which of the following statements is true regarding Xmas Tree Gate Valves?
 - a) Xmas Tree Gate Valves always function as a Tertiary Barrier
 - b) Xmas Tree Gate Valves always function as a Primary Barrier
 - c) Xmas Tree Gate Valves can be Primary, Secondary or Tertiary Barriers, as it depends on the operation and other circumstances

4. How are Hydraulic Packers normally set?
 - a) Run the Packer to depth, then apply pressure to the control line
 - b) First set a plug in the tail pipe, then apply pressure on the tubing
 - c) Run the Packer to depth, then apply pressure against the casing below the tail pipe, provided the well is not yet perforated
 - d) First set a plug in the tail pipe, then apply pressure below this plug
 - e) First set a plug in the tail pipe, then apply pressure on the annulus

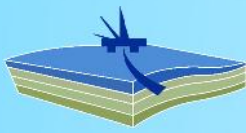
5. What kind of gas is used for the precharge of accumulator bottles?
 - a) Air
 - b) Carbon Dioxide
 - c) Nitrogen
 - d) Hydrogen
 - e) It could be any type of gas



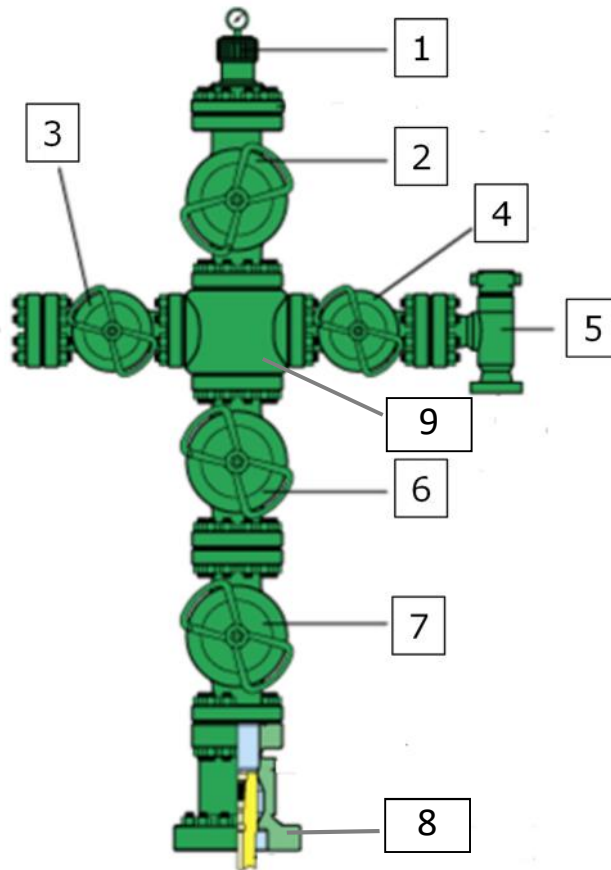


6. What is the API Standard 53 recommended maximum interval between pressure tests for BOPs, before using it for a completion and/or workover operation?
- a) Within 21 days of the last test
 - b) Within 14 days after shutting in on a kick
 - c) Within 7 days of the last test
 - d) No specific requirement after a successful stump test
 - e) No specific requirement as long as there is no leak detected
 - f) No specific requirement as long as we have not performed a repair
7. Which of the following information should be on a BOP barrier test document?
THREE ANSWERS
- a) The test fluid density used for the test
 - b) The test pressure that has been applied to test the barrier
 - c) The type of BOP barrier [e.g. Pipe Rams]
 - d) The name of the person performing the test, including his signature
 - e) The hydraulic pressure with which the BOP was closed
 - f) The manufacturer of the BOPs in use
8. Which of the following statements are true about Xmas Trees?
TWO ANSWERS
- a) Lower Master Valve should be used to cut slick line in case of an emergency
 - b) Upper Master Valve are often designed to cut slick line in case of an emergency
 - c) Flow Wing Valve can be used to cut slick line in case of an emergency
 - d) Swab Valve can be used to cut slick line, but sealing areas may get damaged
9. Which of the following statements are true about Xmas Trees Gate Valves
THREE ANSWERS
- a) A Gate Valve always has an indicator showing how many turns have been made to either open or close the valve
 - b) A Gate Valve always take 30 turns to open or close the valve
 - c) After closing a Gate Valve, some tree valve handles should be backed out by a quarter turn
 - d) After closing a Gate Valve, some tree valve handles should be closed firmly to ensure a good seal
 - e) Always count the turns as the valve is opened or closed, because this provides an indication of any obstruction across the valve, e.g. a tool string



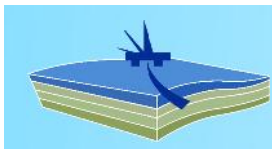


10. Below is a drawing of a composite Xmas Tree. Match the various components with the identification number



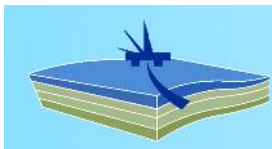
- Lower Master Gate Valve _____
- Tree Cap _____
- Kill Wing Valve _____
- Production Choke _____
- Upper Master Gate Valve _____
- Swab Valve _____
- Choke Line Valve _____
- Flow Cross _____
- Adapter Flange _____





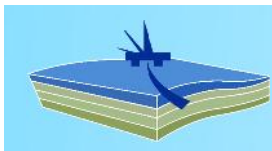
11. What kind of downhole conditions would trigger a sub-surface controlled DHSV to close, depending on its design?
TWO ANSWERS
- a) A change of fluid density, e.g. the packer fluid
 - b) A change of temperature, e.g. the surrounding formation temperature
 - c) A change of pressure, e.g. a sudden decrease
 - d) A change of flow, e.g. a flow increase
12. How should a Down Hole Safety Valve, already installed in the well, be tested?
- a) By slam closing the DHSV under high rate flowing conditions, then checking leak rate
 - b) By closing the DHSV, then pressurizing above it and monitoring the leak rate
 - c) By closing the DHSV, measuring the control line fluid flowback and then performing an inflow test
 - d) By closing the DHSV and measuring the volume of the control line fluid flowback
13. How can a sub-surface controlled DHSV be 're-opened' after it has been closed and the pressure above has been bled off?
- a) By increasing the pressure above the valve until the pressures below and above the DHSV are equalized
 - b) By running and then stabbing an opening device
 - c) By simply opening the well
 - d) By applying additional control line pressure
14. To permit free flow of fluids through the TR DHSV while running the completion, what kind of method can we use?
TWO ANSWERS
- a) Keeping pressure on the control line until we run the Tubing Hanger
 - b) Keeping pressure on the tubing using an Internal Packer
 - c) Using an 'hold-open tool' or 'straddle sleeve' that is locked inside the TR DHSV landing nipple
 - d) Using an 'lock-open' device that is pinned with shear screws
 - e) By using heavier fluid inside the tubing than in the annulus





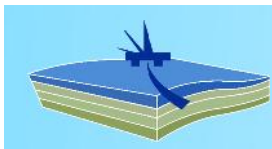
15. How is a WR DHSV kept open while running it on wireline to its landing nipple?
- a) By a prong fitted to the running and retrieving tools
 - b) It is held open by hydraulic pressure on the control line
 - c) By using an 'hold-open-tool' or 'straddle sleeve' fitted inside the WR DHSV
 - d) By using a J-latch device
16. During a test on a TR DHSV we observe that the leak rate is well above acceptable volume per minute. What should we do to re-commence production, but maintain well integrity?
- a) We should use the Annulus Safety Valve instead
 - b) We have no choice then to perform a workover
 - c) We should use well intervention to lock open the TR DHSV
 - d) We should use well intervention to lock open the TR DHSV, then install a WR insert DHSV
17. Which type of Down Hole Safety Valve has the largest 'internal' diameter when comparing it with the internal diameter of the tubing to which it is connected?
- a) A WR Down Hole Safety Valve
 - b) Any DHSV that works on differential pressure
 - c) Any surface controlled DHSVs
 - d) A TR Down Hole Safety Valve
18. What type of closing mechanisms are used in WR surface controlled DHSVs?
TWO ANSWERS
- a) Poppet Valves
 - b) Flapper Valves
 - c) Ball Valves
 - d) Gate Valves
 - e) Choke Valves
19. Which types of the following DHSVs are sub-surface operated?
TWO ANSWERS
- a) Ambient Pressure DHSV
 - b) Differential Pressure DHSV
 - c) WR SC-SSV
 - d) TR SC-SSV
 - e) Ball Valves
 - f) Flapper Valves





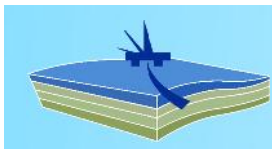
20. How are mandrels of wireline running tools 'locked' into a nipple profile?
- a) By using metal-to-metal seals
 - b) By using wedge type slips
 - c) By using locking dogs that match the nipple profile
 - d) By using steel re-inforced packings that fit tightly inside the nipple profile
 - e) By using a landing ring
21. How do wireline running tools 'seal' inside a landing nipple?
- a) By using a landing ring
 - b) By using elastomer packings which seal across the nipple polished bore
 - c) By using wedge type slips
 - d) By using elastomer packing that seal on the no-go shoulder
 - e) By using metal-to-metal seals
22. What is the primary function of a No-Go in a landing nipple?
- a) To position the appropriate lock correctly, so that the keys engage the profile in the landing nipple profile
 - b) To prevent the wireline plug falling through the bottom of the tubing or casing
 - c) To withstand the force of differential pressure across the wireline plug
 - d) To engage and lock the keys of the wireline plug
23. What is the primary reason for using landing nipples in the completion string?
- a) To serve as a depth reference when running wireline tools
 - b) To enable installation of gas lift valves
 - c) To serve as a latch for anchor seal assemblies
 - d) To enable installation of flow control equipment
24. From which direction should a DHSV be tested?
- a) From above, by applying test pressure
 - b) From below, by inflow testing
 - c) Can always be tested in both directions
 - d) From above, through the control line





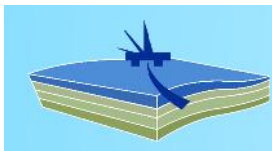
25. What is the primary reason for installing an Annulus Safety Valve [ASV]?
- a) It serves as a back-up to the regular DHSV
 - b) In gas lift wells, it serves to stop flow from tubing to annulus in case the check valves are not holding
 - c) In gas lift wells, it serves to stop flow from the annulus below the valve in case of surface damage or another emergency
 - d) It serves as a back-up production packer
26. What is the primary reason of installing a Down Hole Safety Valve [DHSV]?
- a) It enables shutting in the well for maintenance on the Xmas Tree
 - b) It enables shutting in the well for a temporary suspension of production
 - c) It stops further flow from the well in case of surface damage or emergency
 - d) It stops flow from the annulus in gas lift wells
27. What is the most important condition when determining the setting depth for a Down Hole Safety Valve [DHSV]?
- a) It should be set deep enough to avoid being damaged by surface impact or by explosion damage at surface
 - b) It should be set shallow enough to minimize the consequences of an accidental collision with a deep adjacent well being drilled into the producing well
 - c) It should be set deep enough to prevent sabotage of the valve itself
 - d) It should be set shallow enough to minimize time to retrieve the DHSV for a repair or maintenance
 - e) It should be set shallow enough to minimize loss of well fluid [primarily gas]
 - f) It should be set deep enough to permit gas lifting of the well above it
28. In gas lift wells, what prevents gas flowing back from tubing to annulus?
- a) The differential pressure across the gas lift valve
 - b) The check valve inside the gas lift valve
 - c) The friction effect of gas trying to flow through an orifice
 - d) The dome nitrogen pre-charge setting in the gas lift valve
29. In gas lift wells, what do we install in a Gas Lift Mandrel in order to fully isolate the tubing from the annulus?
- a) A circulation valve
 - b) A gas lift valve
 - c) A gate valve
 - d) A dummy valve
 - e) An injection valve





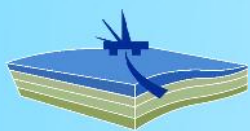
30. Where would be usually place a Sliding Sleeve in a single string completion to produce a single production zone?
- a) Directly above the Production Packer
 - b) Directly below the Production Packer valve
 - c) Between two Production Packers
 - d) Just below the Landing Nipple in the Tail Pipe
31. How will a Production Packer function as a barrier?
- a) By stabbing and then sealing within a Liner Polished Bore Receptacle
 - b) By closing off the flow path between tubing and casing
 - c) By sealing the upper completion string within the bore of the Production Packer
 - d) By hydrostatic pressure manipulation from the annulus
32. What is the definition of a Permanent Packer?
- a) A completion item that is always retrieved with designated retrieving tools
 - b) A completion item that can be installed and retrieved with wireline
 - c) A completion item that can only be retrieved with the tubing in place
 - d) A completion item that can only be removed by milling or using other destructive methods
 - e) A completion item that has a setting mechanism which incorporates a releasing system, allowing recovery of the packer
33. What is the primary purpose of a Permanent Packer?
- a) To isolate the annulus from the tubing and the formation
 - b) To anchor the tubing string
 - c) To support the weight of the tubing
 - d) To isolate the completion fluid above from the hydrocarbons below it
34. What is the definition of a Retrievable Packer?
- a) A completion item that is always retrieved with designated retrieving tools
 - b) A completion item that can be installed and retrieved with wireline
 - c) A completion item that can only be retrieved with the tubing in place
 - d) A completion item that can only be removed by milling or using other destructive methods
 - e) A completion item that has a setting mechanism which incorporates a releasing system, allowing recovery of the packer



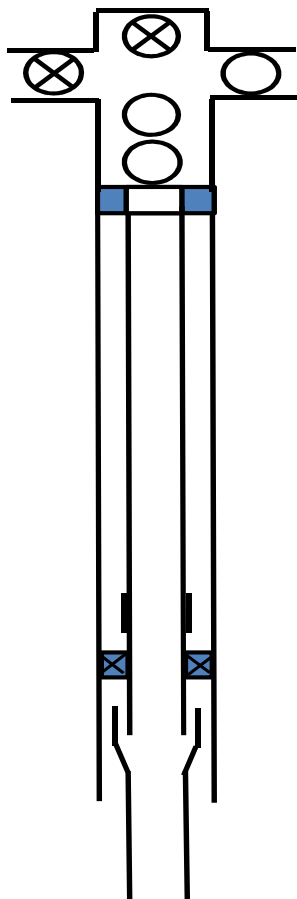


35. How can reverse circulation be established if the Sliding Sleeve is stuck in a closed position?
TWO ANSWERS
- a) By applying torsion to the completion string
 - b) By punching 1 or more holes in the tubing
 - c) By installing a circulation valve in a Gas Lift Valve
 - d) By using the DHSV control line
 - e) There is nothing we can do. Use the bullhead kill method instead
36. Which of the following statements are correct regarding Gas Lift Mandrels?
TWO ANSWERS
- a) The Gas Lift Mandrel allows installation of a gas lift valve
 - b) The Gas Lift Mandrel allows installation of a tubing plug
 - c) The Gas Lift Mandrel allows communication between tubing and annulus
 - d) The Gas Lift Mandrel allows installation of a DHSV
 - e) The Gas Lift Mandrel allows installation of a retrievable tubing bridge plug
37. Which of the following statements show good practices prior 'opening' a Sliding Sleeve in a completed well?
TWO ANSWERS
- a) Check if the pressure rating of the Sliding Sleeve is correct before running it
 - b) Check if the Sliding Sleeve is fully open prior starting any circulation
 - c) Check if the tail pipe has a positive plug installed prior opening the Sliding Sleeve
 - d) Check if the pressure between annulus and tubing at SSD depth is equalized prior opening the Sliding Sleeve
 - e) Check if we have the correct control line pressure for the DHSV being run
38. How do you open a Sub-Surface Controlled Sub-Surface Safety Valve [SSC-SSSV]?
TWO ANSWERS
- a) Pull out SSC-SSSV with wireline and reset setting pressure, then rerun again
 - b) Equalize pressure across the SSC-SSSV
 - c) Pull out tubing to reset SSC-SSSV
 - d) Run opening sleeve to open SSC-SSSV



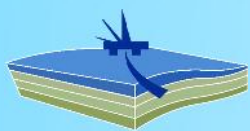


39. You are running a completion in a well designed for water injection [see picture below]. In which 'stroke position' will you set the shear pins or shear ring in the Polished Bore Receptacle [PBR]?

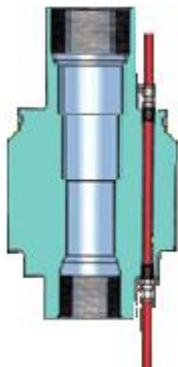


- a) Mid Stroke
b) Bottom Stroke
c) Top stroke
40. A Dump Kill Valve is installed in a Side Pocket Mandrel of a completion string. A small positive pressure is kept on the 'A' annulus between completion string and production casing. What will be the indication that tells you that the Dump Kill Valve may be leaking?
- a) Increase of tubing pressure
b) Decrease of annulus pressure
c) Increase of annulus pressure
d) Rapid drop of fluid level in annulus





41. You are planning to set a positive plug in a tubing hanger profile [see schematic of tubing hanger below]. What kind of seal[s] should be used to ensure this positive plug can hold pressure from above and below?



- a) Not able to be seal in a tubing hanger
 - b) Set chevron seal facing down
 - c) Set chevron seal facing up
 - d) Bonded single elastomer seal
42. You are running a completion assembly with sand screens. The Joint Operations Manual states that if a well control event occurs with a non-shearable assembly across the Shear/Blind Rams, then the procedure is to drop the completion string and close the Shear/Blind Rams. What problem may arise with this procedure?
- a) The well can not be killed through the kill line
 - b) The well can not be killed through the choke line
 - c) Unable to open the elevator due to the weight of completion string hanging on these elevators





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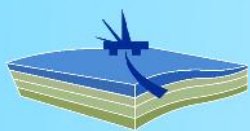


WORKBOOK COMPLETION EQUIPMENT – ANSWER KEYS

EXERCISE COMPLETION EQUIPMENT-1	
1.	b, e
2.	b, c
3.	a
4.	b
5.	a, c
6.	b
7.	a
8.	c
9.	b, d
10.	b
11.	c, d
12.	a, d
13.	a
14.	a, c

EXERCISE COMPLETION EQUIPMENT-2	
1.	b, d
2.	a
3.	c
4.	b
5.	224 minutes
6.	c
7.	a, e
8.	2500 psi
9.	b
10.	c
11.	d
12.	b
13.	d
14.	a, b
15.	d, e





EXERCISE COMPLETION EQUIPMENT-3

1.	b
2.	c
3.	c
4.	a
5.	a, b
6.	c
7.	a
8.	c
9.	b, d
10.	c
11.	a, b
12.	b

EXERCISE COMPLETION EQUIPMENT-4

1.	b
2.	c
3.	a, c, e
4.	c, d, g
5.	b, d
6.	c
7.	d
8.	b
9.	a, b
10.	b
11.	a, c
12.	b
13.	a, d
14.	a
15.	a, d
16.	a
17.	c





18.	b, e
19.	d
20.	c
21.	d
22.	e
23.	b
24.	b, d
25.	b, c
26.	a, b
27.	c



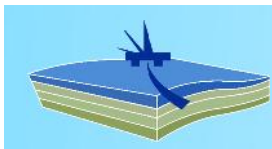


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WIRELINE EQUIPMENT

EXERCISE WIRE LINE EQUIPMENT 1

1. Name the equipment that is used to act as a barrier for a slick line rig up with only a single wireline BOP: -

Primary Barrier: _____

Secondary Barrier: _____

Tertiary Barrier: _____

2. When doing a wireline job on a live well, which of the following statements is true regarding the use of BOPs?

- a) There is no need for blowout preventers when doing wireline jobs, because we can close the Xmas Tree valve
- b) Wireline blowout preventers operate in a similar way as pipe rams
- c) The blowout preventer stack is supported by a telescoping gin pole
- d) Ram type preventers cannot be used because the rams do not form a good seal around a wire

3. How will the tension reading be affected if the angle between slick line and the slick line sheave pulley is more than 90 degrees?

- a) It will show less (but tension at load cell will be more)
- b) It will show more (but tension at load cell will be less)

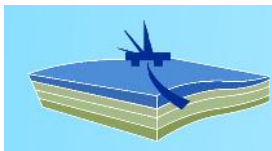
4. Which of the following component can never be part of a lubricator section?

- a) Pressure Gauge
- b) Quick Union 'O' ring seal
- c) Rope socket
- d) Bleed-off valve

5. What is the main purpose of having wireline BOPs installed on the well?

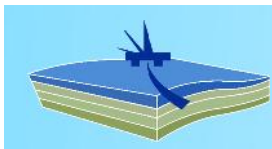
- a) To provide a much improved protection against well pressure over that of the stuffing box.
- b) To contain well pressure and enable to repair and change components if any connection above the BOPs should leak.
- c) To permit pressure testing of lubricator assembly and stuffing box.
- d) To provide a tool trap, preventing the tool string from dropping back into the well when they are pulled hard against the stuffing box





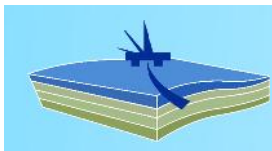
6. Which one of the following statements is true regarding braided line Grease Injection Heads (GIH)?
- a) It is the applied hydraulic pressure that pushes up the pack-off which makes the seal around the braided line cable.
 - b) It is the wellhead pressure that pushes up the pack-off which makes the seal around the braided line cable
 - c) It is the grease that is pumped into the flow tube through the lower grease inlet which makes the seal around the braided line cable
 - d) It is the grease, pumped into tubes through the upper grease inlet which makes the seal around the braided line cable
7. Which component is the primary barrier during a slick line operation?
- a) Wireline BOP
 - b) Lubricator
 - c) Stuffing box
 - d) Upper Master Valve
8. In which case/situation should the Slick Line BOP always be closed? (TWO ANSWERS)
- a) When changing the tool string or running tool.
 - b) When the wire has to be wiped cleaned when pulling out of hole.
 - c) When the wire parts near surface and has fallen down into the well.
 - d) When a broken wire has been successfully fished and then has to be reeled back onto the drum through the Stuffing Box.
 - e) When a tool gets stuck in the hole and the Cutter Bar has to be dropped.
9. When using a braided line BOP, what is the main reason to install a lower ram upside down?
- a) It is standard design for ram preventers to hold pressure from below.
 - b) It improves the overall weight balance of the braided line BOP.
 - c) It allows a pressure test of the lubricator and GIH assembly.
 - d) The lower ram will only function with grease pressure from above, not well pressure.
10. What are the advantages of installing a wireline BOP directly on top of the Xmas Tree? (THREE ANSWERS)
- a) Will have less potential leak paths between barriers
 - b) Be able to maximize length of the lubricator above the wireline BOP
 - c) It will minimize the potential of getting a tool stuck across the Xmas tree
 - d) It will reduce the use of Xmas Tree valves to function as barriers
 - e) Provide good handling access to the X/mas Tree and BOP





11. What is the main purpose of having a Ball Check Valve or Safety Check Union installed below the Grease injection head when running the braided line?
- a) To clean the grease off the braided line while pulling out.
 - b) To prevent both grease and well fluid from contaminating each other.
 - c) To prevent escape of well bore fluids through the GIH in case the cable would part at surface.
 - d) To prevent well bore fluids from entering the Chemical Injection line.
12. After closing the wireline BOP and before breaking out the lubricator, what action must be carried out before we can proceed? (THREE ANSWERS)
- a) Kill the well
 - b) Inflow test the wireline BOP
 - c) Pressure test the wireline BOP
 - d) Lock the hydraulic rams by screwing in the manual stems
 - e) Bleed off well pressure above the closed wireline BOP
13. What is the best description of 'Explosive Decompression' with regard to Wireline Seal elements?
- a) The damage that occurs to packing elastomeric elements when they impact with wireline tool strings just after shut in well with the wireline BOP.
 - b) When trapped gas in micro pores of sealing elements rapidly expands due to a release of surrounding pressure causing damage to sealing elements such as tears, holes, blisters and cracks.
 - c) The explosive damage that occurs when a wireline cable has been stripped through a closed wireline BOP due to excessive tool string weight.
 - d) The damage that occurs when due to extreme temperatures of the wellbore fluids tool string seals compress/decompress and become rapidly torn up.
14. What is a safe and recommended practice when bleeding down pressure from pressure control equipment installed above a closed BOP (on land wells)?
- a) Bleed off pressure directly into the atmosphere in case of hazardous fluids in the well.
 - b) Bleed off pressure by using a temporary flare stack in case of hazardous fluids in the well.
 - c) Bleed off pressure through a buffer tank to allow for a controlled expansion.
15. The slick line has broken off near surface and the wire has dropped down the well. Meanwhile the remaining wire blew out of the stuffing box by well pressure. What is the primary barrier to prevent the well pressure from being released to atmosphere?
- a) Down-Hole Safety Valve
 - b) Stuffing Box Plunger
 - c) Lower Master Valve
 - d) Swab Valve





16. Referring to question no. 15, what is the secondary barrier?

- a) Down-Hole Safety Valve
- b) Stuffing Box Plunger
- c) Lower Master Valve
- d) Swab Valve

17. After a slick line parted and was lost down hole, a plan is made to fish the slick line out with braided line. What are recommended procedures in order to perform this operation safely? (TWO ANSWERS)

- a) It is necessary to rig up both slick line and braided line BOPs before we can perform a fishing operation.
- b) The lubricator must be changed out to one of higher rated working pressure.
- c) Modify and redress the slick line BOP so that it can be used as single braided line BOP.
- d) It is required to assess the need to pick up extra lubricator sections to accommodate both fishing tool string and fish of the slick line tool string.

18. If a Quick Union of a lubricator is made up by hand, could this cause a leak path?

- a) No (as it designed to be made up by hand and still create an effective seal)
- b) Yes

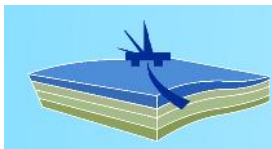
19. What are primary barriers of a completed well? (TWO ANSWERS)

- a) Wellhead Side Outlet Valves
- b) Production Packer
- c) Production String (Tubing)
- d) Completion Fluid

20. A wireline job has been scheduled on a well that is in production. Which of the following precautions must be taken to ensure the SCSSSV stays open during these wireline operations? (TWO ANSWERS)

- a) Install a fusible plug on the hydro-pneumatic actuator
- b) Monitor the pressure on the control line from the production control room
- c) Install a needle valve on the tubing spool to lock-in the control line pressure
- d) Run a straddle sleeve to ensure the SCSSSV stays open at all times

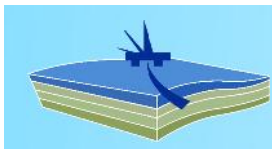




EXERCISE WIRE LINE EQUIPMENT 2

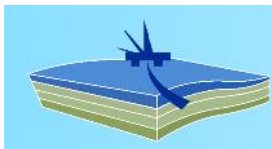
1. What are the main purposes of having a BOP? (TWO ANSWERS)
 - a) To provide better protection and pressure control than provided by a Stuffing Box
 - b) To perform the job safely and to contain well pressure
 - c) To clean the wire when pulling out of hole so that we save time
 - d) To enable the repair of any connection or pressure control equipment above the BOPs, that may start to leak
2. Which of the following statements is correct if a single BOP is used?
 - a) The single Ram BOP holds pressure from both above and below
 - b) The single Ram BOP only holds pressure from below
 - c) The single Ram BOP only holds pressure from above
3. In which situation should a wireline BOP be used?
 - a) When we want to clean the wire during pulling out of the hole
 - b) When we need to lay down or make up a wireline tool string
 - c) When we want to replace or energize the packing unit in the stuffing box
 - d) When we to catch the tools string if the wire would unexpectedly break
4. Which of the following are advantages of setting a wireline BOP directly on top of the X/mas tree? (THREE ANSWERS)
 - a) It provides a more direct access to the X/mas tree and well head.
 - b) It allows the running of full bore tools without any obstructions.
 - c) There are less potential leak paths between the barriers.
 - d) It allows retrieval of a full bore tool in case it gets stuck in the Xmas tree.
 - e) It allows a maximum lubricator and riser length to accommodate longer tools.
5. Before exposing the riser or lubricator to the well pressure (i.e. before opening a Swab Valve), what has to be checked? (THREE ANSWERS)
 - a) We have to check that the hydraulic pump is connected.
 - b) We have to ensure that the lubricator is in a vertical position.
 - c) We have to check that the seal faces and 'O' rings are in good condition.
 - d) We have to check that the pressure rating is equal to or greater than the maximum operating pressure.
 - e) We have to pressure test the lubricator to at least 3000 psi.
 - f) We have to pressure test the riser or lubricator, as a part of the rig up, to at least the minimum SITHP.





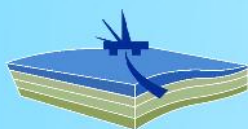
6. In which situation would you have to rig up for an additional wireline?
- When operating in a high angle hole or horizontal well.
 - When we have to perform a fishing operation.
 - When we have to make the lubricator longer
 - If a leak develops in the primary BOPs
7. Which of the following statements are true when rigging up slick line on a well?
(TWO ANSWERS)
- A damaged lubricator needle valve or gauge connection may cause a lubricator nt to hold pressure
 - If the BOP stems are not screwed in all the way, they may cause a leak in the BOP
 - A damaged quick union 'O' ring and/or seal surfaces may cause a leak at the union
 - A quick union only made up hand tight may cause a leak at that union
8. Where is the Safety Check Union installed?
- Below Lubricator and above BOP
 - Below Stuffing Box
 - Below the Grease Injection Head (GIH)
 - Immediate above X/mas tree
9. Are inner seals of a Ram the same for Slick line and Braided line?
- YES
 - NO
10. Can a Tee-Gate valve [e.g. a wellhead or Xmas Tree valve] on a wireline rig up be a primary barrier?
- YES
 - NO
11. During a casing cement job, we observe to have significant losses. Which one of the following statements is correct?
- Run cement bond log (CBL) to check cement integrity. We may need to perform a cement squeeze job
 - Do nothing. The casing is strong enough, in term of capability and integrity
 - Drill out the casing shoe and perform a leak-off test. If okay, continue operations.
 - Determine additional cement volume required to make up for the observed losses



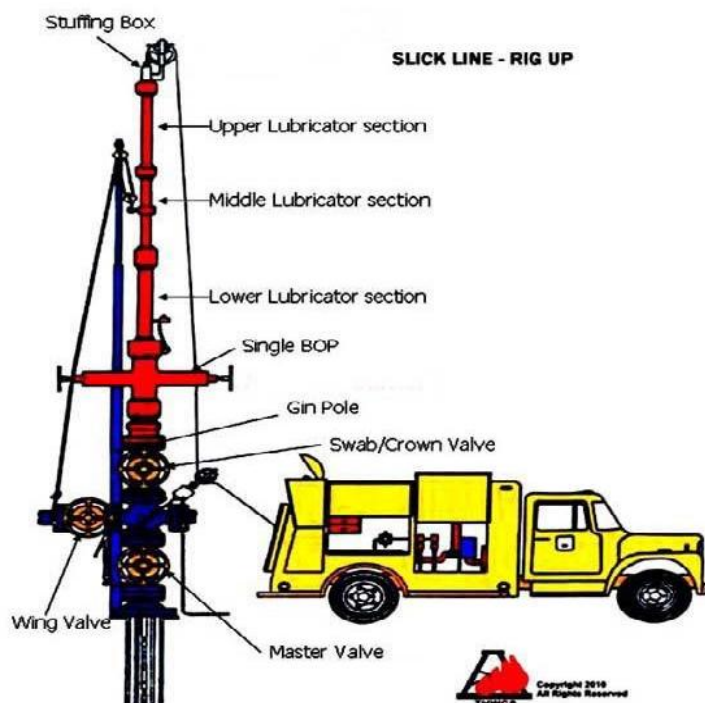


12. During wireline operations, hydrates have formed at stuffing box. Which one of the following statements is correct?
- a) It is formed because of a leakage at the stuffing box
 - b) It is formed because of the cold weather
 - c) It is formed because of the wireline hanging up inside lubricator
 - d) It is formed because the wireline is jammed inside stuffing box
13. There are cracks, holes and blisters on the seal elements of the ram assembly. What is the likely cause of this?
- a) Elastomeric Expansion
 - b) Explosive Decompression
 - c) Sealing Element Explosion
 - d) Sealing Element Ageing
14. Does well pressure increase the sealing capability of the GIH when running a braided line cable during fishing or logging job?
- a) YES
 - b) NO
15. During which situation do we need to pick up extra lubricator sections and rig up with braided line pressure control equipment?
- a) Before we can start with a wireline fishing operation
 - b) When we have to run braided line into high pressure gas well
 - c) When the stuffing box needs to have a back-up for pressure containment
 - d) When the wireline has to be cut down hole
16. The Ball Check Valve (Safety Check Union) does not seal well pressure when tested. Do we need to change this Ball Check Valve before running the braided line operation?
- a) YES
 - b) NO





17. Identify the Barrier Group of this rig up?



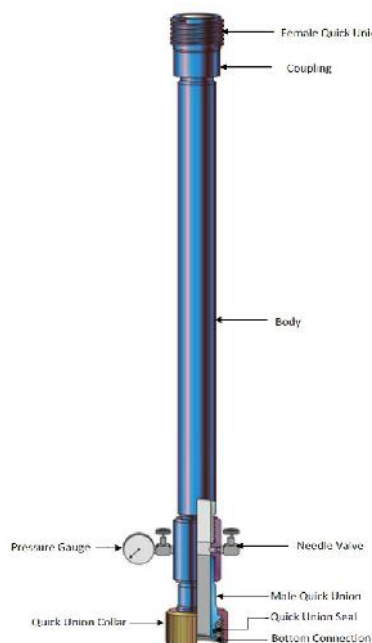
a) Primary Barrier:

b) Secondary Barrier:

c) Tertiary Barrier:

18. Control Equipment (PCE) is rigged up on well and the pressure test is taking place by applying low pressure first and then the full well pressure.

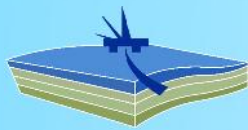
The quick union between the lower and the middle section of the lubricator starts to leak at low pressure, but not at a high test pressure.



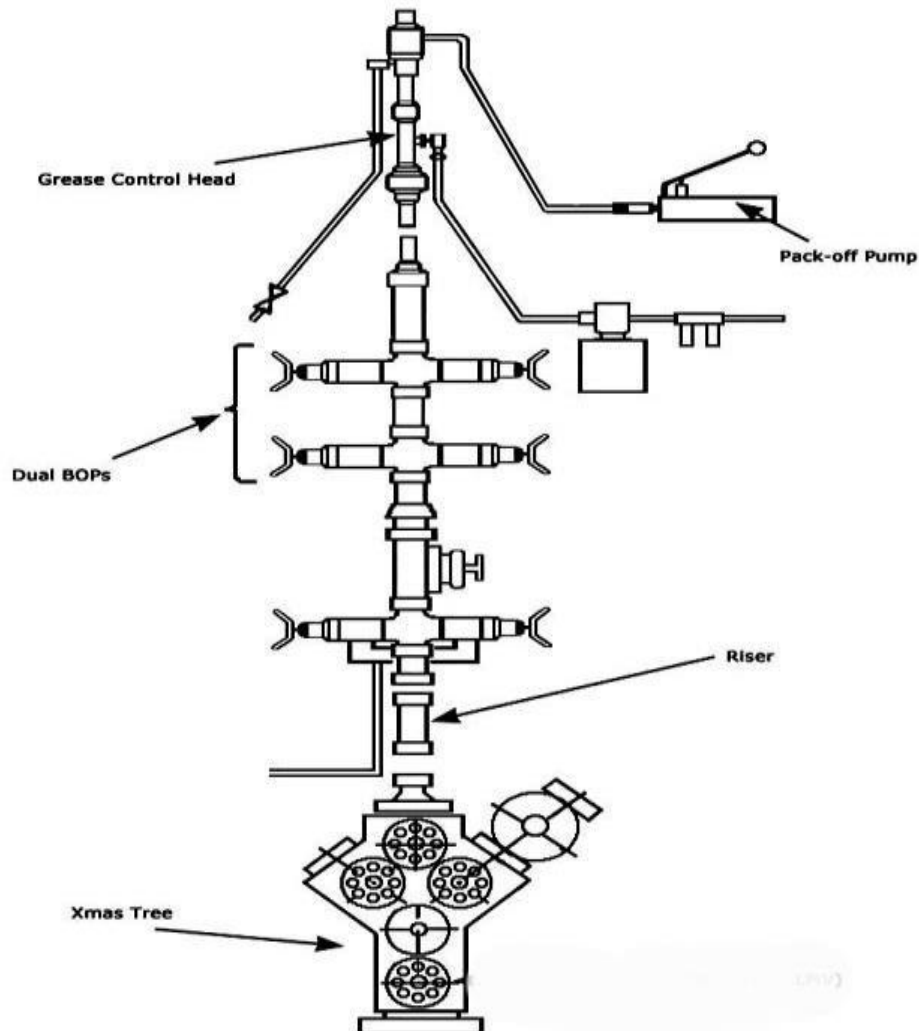
What is the likely cause of this problem?

- a) The 'O'-ring groove at the leaking connection is somewhat worn
- b) The 'O'-ring has split or has a cut
- c) The Female Internal Bore at the leaking connection has a worn surface
- d) The [Male] Box ACME connection at the leaking connection shows handling damage in some places



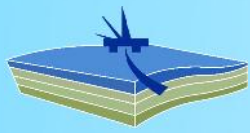


19. Identify the barrier group of this rig up: -



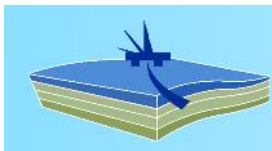
- a) Primary Barrier: _____
- b) Secondary Barrier: _____
- c) Tertiary Barrier: _____





20. When the slick line cable breaks off from the rope socket and the wire is blown out from the Stuffing Box, what is then the closable barrier that comes into effect and acts as a primary barrier?
- a) Stuffing Box Plunger (internal BOP)
 - b) DHSV
 - c) Swab valve
 - d) Ball Check valve
 - e) BOP
21. A dual BOP with a lower inverted ram is installed on the well. There is no Shear/Seal or other type of wire cutter rigged up on top of the X/mas tree valve. To get Double Barrier Protection, which of the following is correct?
- a) A Dual Ram BOP can be supplemented by a 2nd identical Dual Ram BOP.
 - b) A Dual Ram BOP can be supplemented by a Shear/Seal BOP.
 - c) A Dual Ram BOP can be supplemented by a 2nd Single Ram BOP.
 - d) A Dual Ram BOP is sufficient.





EXERCISE WIRE LINE EQUIPMENT 3

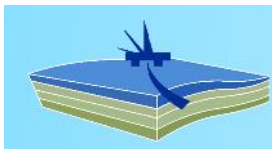
1. A wireline BOP has a temperature rating of -20 to +120 °C. The seal element has a temperature rating of -20 to 90 °C. The well head assembly has temperature rating of - 20 to 180 °C. What is the maximum rated temperature of this wireline stack?
 - a) 180 °C
 - b) 90 °C
 - c) 120 °C
 - d) 60 °C

2. What is the correct procedure to shut in well after pulling a tool string out of hole? (THREE ANSWERS)
 - a) Close Swab Valve and Upper Master Valve, bleed off and unscrew lubricator
 - b) Inform Supervisor
 - c) Check tool string pulled into lubricator, e.g. by counter, by sound, by 'feeling' the wire or by use of a tool catcher
 - d) Close Swab Valve and count turns
 - e) Note the time
 - f) Close and inflow test Upper Master Valve
 - g) Close Upper Master Valve, inflow test, close Swab Valve

3. What are the appropriate actions when running a tractor in a horizontal well and encountering a blockage? (TWO ANSWERS)
 - a) Continue as tractors are not stopped by sand nor debris piled up
 - b) Continue as a collapsed liner or casing is not a possible cause
 - c) Nothing can be done. Abort operation
 - d) As there is a possible sand blockage, we must circulate the sand out first, then try to pass with the tractor once more
 - e) Investigate well conditions first before proceeding with next step

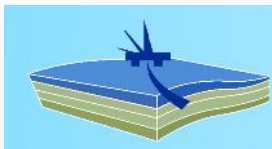
4. You are running braided wireline. When the grease injection seal is lost and observe a small leak, you attempt to re-energize the seal but that has failed. What action[s] is/are required to give you an opportunity and enough time to repair the GIH?
 - a) Close the grease return
 - b) Increase the grease injection pressure
 - c) Stop cable movement. Close both braided line rams and inject grease between them
 - d) Stop cable movement and close the Pack-Off [Stuffing Box]
 - e) Stop cable movement





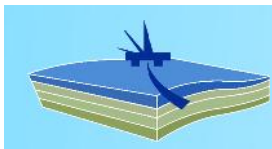
5. The wireline rig-up consists of;
Stuffing Box – Lubricator – Single BOP – Swab Valve – Wire Cutter Master Valve
Identify primary and secondary barrier if wire is blown out of well?
- | | |
|---------------------------|--------------------------------------|
| a) Primary – Swab valve | Secondary – Wire Cutter Master Valve |
| b) Primary – Stuffing box | Secondary – Swab Valve |
| c) Primary – Single BOP | Secondary – Swab Valve |
| d) Primary – Single BOP | Secondary – Wire Cutter Master Valve |
6. You are rigging up on a well with 5,000 psi wireline equipment. Prior to perforating the well, the max. WHP is 4,800 psi. Well depth is 12,892 ft. and the hole filled with 9.1 ppg. After perforating, WHP has risen to 5,020 psi.
What action should be taken?
- a) Check gauge calibration
 - b) Stop and call engineer in charge
 - c) Carry on as it's within 10% safety margin
 - d) It's OK as the fluid is 9.1 ppg. Fluid will reduce the BHP
7. During a wireline run in the well, the weight indicator shows a sudden drop in tension and is not going down anymore. What are the most likely reasons for this to happen? (TWO ANSWERS)
- a) The tool string has hit a gas pocket or a change to low density well fluid
 - b) The tool string has hit some deposited scales in the well
 - c) The tool string is now running through high angle section of the hole
 - d) The wire has parted
 - e) The production tubing is buckled close to the production packer
8. During a wireline run in the well, the weight indicator shows a gradual drop in tension, but the tool string is still going down. What is the most likely reason for this to happen?
- a) The wireline tool string hits the gas or change to low density of well fluid
 - b) The wireline tool string hits some deposited scales in the well
 - c) The wireline has run through high angle section of the hole
 - d) The wireline is broken in the well
9. Considering wireline surface equipment, which barrier components should, as a minimum, be available for a Slick Line operation, but not for a Braided Line operation? (TWO ANSWERS)
- a) Stuffing Box
 - b) Riser
 - c) Single BOP
 - d) X/mas tree





10. You are currently running Slick Line in the well. If you want to run Braided Line for a fishing job, what change should be made in order to run this braided line safely?
- a) Slickline BOP should be supplemented with a Dual Ram Braided Line BOP
 - b) Slickline BOP should be supplemented with Single Ram Braided Line BOP
 - c) Do nothing, the current rig up is OK
 - d) Remove Slickline BOP and replace with a Dual Ram Braided Line BOP
11. Which two of the following statements are correct regarding Wireline Shear Rams?
(TWO ANSWERS)
- a) All Shear Rams have a seal
 - b) Some Shear Rams have an integral seal
 - c) Some Shear Rams are combined with a Blind Ram
 - d) Shear Rams do not have seals





EXERCISE WIRE LINE EQUIPMENT 4

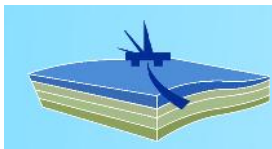
1. We are testing a Braided Line BOP on the Xmas tree using a Test Rod and Lubricator Pack-Off. Which barriers are required to be closed?
 - a) Master Valve, SSSV (not tested)
 - b) Swab Valve, BOP
 - c) Master, swab, Kill Wing & Flowing Valve
 - d) Swab Valve & Wing Valve

2. We have installed a Dual Ram BOP [with a bottom inverted ram] on the wellhead. We have no wire cutting valve on the Xmas tree. In order to achieve double barrier protection, what is considered correct?
 - a) Dual Ram BOP can be supported by a 2nd Dual Ram BOP, identical to the 1st Dual Ram BOP
 - b) Dual Ram BOP can be supported by a Shear/Seal BOP
 - c) Dual Ram BOP can be supported by a second Single Ram BOP
 - d) Dual Ram BOP already qualifies as a double barrier protection

3. Which of the following statements are correct when using BOP Shear Rams? (TWO ANSWERS)
 - a) They will not cut anything other than a single wire.
 - b) They will not cut any tool string nor any wireline tools.
 - c) They will not cut any tool strings, but only wireline tools.
 - d) They may cut as many as 8 to 10 conductor wires going through BOPs.

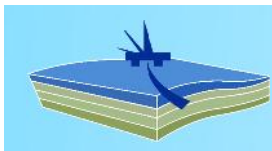
4. We are checking seals and sealing surfaces on the quick unions during a rig-up. Which of the following findings would disqualify the O-rings from being used? (THREE ANSWERS)
 - a) O-ring fits very tight
 - b) O-ring has a black color
 - c) O-ring is slack or oversized in groove
 - d) There is no back up O-ring
 - e) There are cuts and cracks on the O-ring
 - f) There is a smooth surface on the O-ring
 - g) The O-ring is flattened and has a worn surface
 - h) A thin line on the outside of O-ring





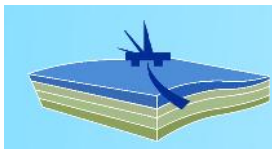
5. After setting a deep-set retrievable bridge plug, it was observed that the plug failed to hold the required pressure. What are the correct actions to take? (TWO ANSWERS)
- If the leak is small, then do nothing as this is, generally speaking, acceptable
 - Mobilize Coiled Tubing and place a cement plug on top of it
 - Pull the plug and replace it with a new plug
 - Mill the plug out and set a new plug
 - Set a back-up plug above the first plug
6. During a fishing job for a lost wireline plug in the well, it was observed that the line tension was 90% of max. permissible tension. You walk the line and notice a leak at the Hydraulic Stuffing Box. You attempt to pressure up on the Stuffing Box, but the in-line filter (which is a part of pump) appears to be blocked and we are unable to apply sufficient pressure. What should you do to bring the well back in safe condition?
- Remove in-line filter, pump up Packing of Stuffing Box, then release from the fish and POOH. Repair or replace Hydraulic Pump.
 - Close BOP. Advise OIM for the need to bullhead the well.
 - Remove in-line filter, pump up Packing of Stuffing Box and return to fishing
 - Do nothing as the wireline is under tension and once the tension decreases somewhat, then wireline will seal properly in the Stuffing Box.
7. We have pulled out of the well with wireline and the tool string is currently inside the lubricator. We have closed the Swab Valve and are in the process of performing an inflow test. What action should be taken if the Swab Valve fails this inflow test?
- Stab the Lubricator back on
 - Energize the Stuffing Box
 - Close the Upper Master Valve
 - Close the SC-SSV
8. For a slick line rig-up, we are putting measures in place to mitigate the consequences of a primary barrier failure. Where should these measures be documented?
- In the job risk register
 - In the incident report
 - In the well file
 - In the daily morning operations report





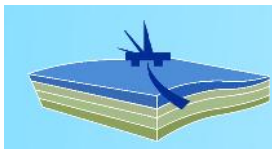
9. After re-perforating a live well on e-line, a gun has been pulled back to surface. Suddenly, the gun got stuck across the Xmas tree. The 'top' of the gun tool string is above the Dual Ram BOP. If the tool string cannot go up or down, what action should we take?
- Pull the weak point at the rope socket and rig up another set of Dual Ram BOP
 - Prepare to kill the well (no mechanical barrier left in this case)
 - Close the SC-SSV and perform an inflow test. Disconnect and pick up the lubricator and remove the perforating gun by mechanical force
 - Pressure up above the gun in an attempt to push the string back into the well
10. List precautions that should be in place when recovering a suspected 'hot' (unfired) gun at surface (THREE ANSWERS).
- Remove all non-essential personnel from the area
 - Stop at a safe depth and discuss all necessary precautions with essential personnel
 - Call the location manager for advice
 - Unit switched off and the key removed
 - Wire clamped and flagged
 - Grease injection head relaxed to avoid the tool string 'hanging up'
11. What is the principle reason for conducting a pressure test of a wireline lubricator package (include the BOP and riser) prior introducing well fluids?
- To verify integrity of the primary well control envelope
 - To comply with regulatory test requirements
 - To test the wireline BOPs
 - To verify integrity of Xmas Tree Valves
12. Whilst using braided e-line on a live well, the wire parts and is ejected from the well. What immediate action should you take?
- Close the Dual Ram BOPs. Bleed down the Lubricator.
 - Close in the Xmas Tree Upper Master Valve. Bleed down the Lubricator.
 - Pump up and energize the Grease Injection Head.
 - Contact production to report the incident.
13. While running deep into the well with a slick line drift tool, the wire parts at surface and the wire tail falls into the well. What would normally be the first intervention run prior any fishing operations?
- Blind box run to tag rope socket and release wire from tool string.
 - Wireline grab to locate and attempt to 'pick up' wire tail.
 - Wire-finder to locate top of wire.
 - Run with overshot to swallow rope socket fishing neck.





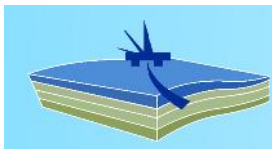
14. Which Xmas tree valves should be closed and tested before rigging up for a well intervention operation?
- a) Swab Valve and Upper Master Valve
 - b) Swab Valve and Upper Master Valve, Flow Wing Valve[s], Kill Wing Valve[s]
 - c) SC-SSV and Swab Valve
 - d) Wireline BOPs
15. A slick line tool string is stuck in the well. An attempt to jar free has been unsuccessful and the decision has been made to drop a cutter bar. The lubricator has been lifted and the cutter bar is inserted over the wire. What is the primary barrier now and how will it be verified?
- a) The Stuffing Box. This has been tested at the start of the operation and its integrity maintained by a continuously applied hydraulic pressure on the packing
 - b) The Dual Ram BOPs. These are closed. The upper ram is inflow tested, after which the lower ram is inflow tested with the equalizing port between the two rams in an open position.
 - c) The Xmas Tree Valves. These are inflow tested to provide a double barrier against any possible flow
 - d) The Wireline Riser. As it stills contains pressure an therefore providing a satisfactory verification of its own integrity.
16. When pulling out of hole after logging operation, the weight indicator starts acting sluggishly and unexpectedly starts to show increasing tension. What could have happened?
(TWO ANSWERS)
- a) A broken strand is making a bird nest inside the lubricator.
 - b) The wire is not properly lubricated.
 - c) The engine oil filter should be changed immediately.
 - d) The weight indicator showing the wrong tension.
 - e) Hydrates may be forming in the well or across pressure control equipment
17. What is the correct braided line ram configuration (from top to bottom)?
- a) Braided Inverted, Braided normal, Shear Seal
 - b) Braided Normal, Braided Inverted, Shear Seal
 - c) Braided Inverted, Shear Seal, Braided Normal
 - d) Shear Seal, Braided Normal, Braided Inverted





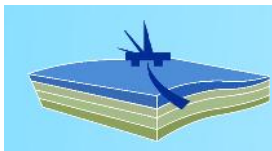
- 18.** We are running a memory gauge at the bottom of the hole and observe that the control pressure for the TR-SCSSV reads zero psi. What is the correct action to take?
- a) It is best to do nothing and check this out later
 - b) Re-establish control line pressure and pull out of hole, checking wireline for damage. Perform integrity test on TR-SCSSV before re-running memory gauge
 - c) Re-establish control line pressure and complete run with memory gauge
 - d) Re-establish control line pressure and pull out of hole. Run a Hold-Open Tool for TR-SCSSV and complete run with memory gauge
- 19.** Which of the following statements is true when pressure testing the wireline rig up with tool string installed in the lubricator?
- a) In order to get the Stuffing Box to seal properly, the pressure must be applied as fast as possible
 - b) The pressure is applied through a test port in the Stuffing Box
 - c) The pressure must be applied slowly to avoid pushing the rope socket into the underside of the Stuffing Box
 - d) An equipment set with a working pressure of 5,000 psi must always be tested to 5,000 psi, regardless of the SITHP
- 20.** We are running braided line in the hole at depth of 3,000 ft. The brass bushing and cable rubber in the grease head body are not functioning properly. It creates a problem on the hydraulic pack off unit which can no longer hold any pressure. What is the correct action to take?
- a) Stop the grease pump which energizes the pack-off
 - b) Close the Dual Ram BOPs
 - c) Increase the grease pressure
 - d) Close valves on Xmas Tree
- 21.** An accident occurs during a rig up of wireline PCE equipment on the well head. The lubricator has dropped from a height, resulting in minor damage on the ACME [male] pin end connection of this lubricator. However, the seal element of this quick union connection was still in good condition. Will you use this lubricator for the job in hand?
- a) Yes, because its pressure integrity is OK for this job.
 - b) No, it is needed to be repaired and re-certificated by OEM.





- 22.** The low and high pressure tests are normally performed on components that are exposed to well pressure. Which statement is true regarding this pressure test?
- a) If no visible leakage observed, it is OK and accepted.
 - b) The acceptance criteria shall be found in relevant documents such as well program, API, NORSOK or manufacturer recommendation.
 - c) Acceptance must be 10% of its integrity.
 - d) Acceptance must be 20% of its integrity.
 - e) Acceptance must be 5% of its integrity.
- 23.** During a maintenance check on wireline BOP, it was found that one of the Ram Assemblies had a seal that was swollen as a result of saturated oil from the well. What should be done?
- a) Fully redress the BOP and change out all seals
 - b) It is only necessary to replace the swollen seal
 - c) No need to change anything at this moment in time. The pressure test will tell you more conclusively if a change is necessary
 - d) Place the swollen seal in a 'cold' pack. This will allow the oil to come out and the seal can then be used again
- 24.** What is the best statement which describes what the Shear/Seal BOP can or cannot do?
- a) A Shear/Seal BOP should be able to cut the tool string at any point. If not, the tool string (BHA) should be made up such that a combination of lubricating or cutting can be done. The BOP should seal off the well.
 - b) The Shear/Seal BOP should be able to cut tool string at any point and seal off the well after cutting.
 - c) The Shear/Seal BOP should be able to cut tool string at any point

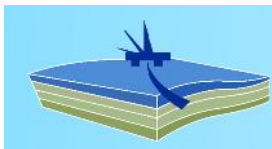




END-OF-COURSE PAPER WIRELINE EQUIPMENT 5

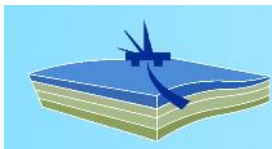
1. We are testing the braided line BOP with a test rod. We do not have a Pump-in Tee below the BOP. Which 'other' barriers must be closed when performing this test?
 - a) The Swab Valve and Kill Wing Valve
 - b) The Upper Master Valve, Swab Valve, and inner Flow Wing Valve
 - c) The Upper Master Valve and inner Flow Wing Valve
 - d) The Upper Master Valve and Down Hole Safety Valve
2. During a slick line job, we experience a failure of the hydraulic system. We are unable to use the hydraulic system to close the BOP. Which of the following statements is true if an attempt is made to manually operate the Shear/Seal Rams?
 - a) The Shear/Seal Rams can be made to shear and seal
 - b) The Shear/Seal Rams cannot be made to operate
 - c) The Shear/Seal Rams can be moved and will shear, but not seal
 - d) The Shear/Seal Rams can be moved and will seal, but not shear
3. The operating temperature of the BOP in the manufacturers' data is 250 °F. The temperature rating of the elastomers is 170 °F. What is the maximum well fluid temperature at which the BOPs should be used?
 - a) 170 °F
 - b) Unable to say. It also depends on the temperature on location
 - c) 250 °F
 - d) It only depends on the temperature on location
4. During e-line operations we use a Shear/Seal BOP. Which of the following statements is correct?
TWO ANSWERS
 - a) It will be able to cut 8 to 10 wires
 - b) It will only cut a single wire
 - c) It may not cut the tool string nor wireline tools
 - d) It will cut the tool string, but not the wireline tools
5. While running a tractor in a horizontal we experience hanging-up of the tool. What would be the most appropriate action to take?
 - a) Pull out of hole and make a number of runs to bail out the sand blockages
 - b) Reverse clear of the blockage and evaluate the well conditions and nature of the blockage before making the next move
 - c) Continue moving forward and try to work through the obstruction





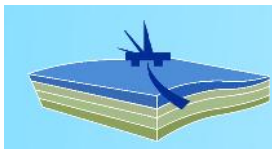
6. We intend to use slickline to pull a wireline-set BPV from the Tubing Hanger. Where should the wireline BOPs be located?
- a) At a height above the Xmas Tree, which would accommodate the entire tool string inside a riser, when we latch onto the BPV
 - b) As close to the Xmas Tree as practically possible
 - c) Removing a BPV is not a critical operation, so any height that is convenient for the crew is more important
7. A low and high pressure was conducted on a wireline lubricator. We observed a leak between the lubricator's lower sub and the quick union. The pressure leaked off at low pressure, but held at high pressure. What is the most probable cause?
- a) The 'O' Ring may be split
 - b) The seal faces on the box end of the quick union may be worn or damaged
 - c) The 'O' Ring groove may have some scratches
 - d) The seal faces on the pin end of the quick union may be worn or damaged
8. The slickline tool string has become stuck and is located across the Xmas Tree and wireline BOP. As we are trying to free the tool string, the wire breaks and is blow out of the well. What barriers are now available to control well pressure?
- a) By closing the DHSV we create a barrier
 - b) The plunger in the Stuffing Box will automatically seal off the well
 - c) The well must be killed and the kill brine will create a barrier
 - d) The packing of the Stuffing Box will seal off the well when the packing nut is tightened or the hydraulic pressure is increased
9. A Gate Valve is in a closed position with 3500 psi on one side and 0 psi on the other. Which of the following statements are true about opening this valve?
TWO ANSWERS
- a) The equalizing port in the gate ensures that the pressures are equalized across the valve the moment we start opening it
 - b) The sudden pressure surge can damage equipment downstream of the flow being released
 - c) All valves are designed to be opened with pressure on one side only
 - d) The mechanical force required to turn the valve handle can damage the stem and the gate
 - e) The high differential pressure assists the gate to move when opening it





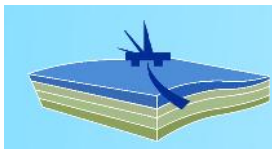
10. We are rigging up for a braided line activity. The dual braided line BOP has a grease injection system that is connected between the rams. Which of the following statements is true?
- a) The dual braided line rams can be considered as two barriers
 - b) The dual braided line rams can be considered as one barrier
 - c) The lower braided line ram can be considered as the tertiary barrier
11. We are running braided line with a Grease Injection Head, but are unable to create a satisfactory seal, no matter what we try. What is the best action to take?
- a) The only safe action to take is to kill the well. We can then repair and replace the Grease Injection Head or flow tubes
 - b) Activate the Shear/Seal. Then perform an inflow test. We can then repair or replace the Grease Injection Head or flow tubes. If okay, then fish and recover the wireline tools and wire.
 - c) Close the dual braided BOPs and pump grease between them. Then perform an inflow test. We can then repair or replace the Grease Injection Head or flow tubes.
 - d) This a problem that often occurs. Increase hydraulic pressure on the Stuffing Box and pull out of hole. We can then repair or replace the Grease Injection Head or flow tubes.
12. We are running slickline with a Memory Logging Tool as part of the tool string. The tool is now close to the bottom of the well. We observe that the control pressure on the TR-SSV has been lost and reads zero psi. What action should we take?
- a) Re-establish control line pressure. If it can be maintained, then complete the logging run.
 - b) This should not be a problem. Continue with the job. If we have a problem with pulling the tool string past the TR-SSV, then pull out of the rope socket and retrieve the wire. We can then lock the TR-SSV open and fish for the tool string
 - c) Re-establish control line pressure. If it can be maintained, then pull out of hole and inspect the line that was across the TR-SSV. In addition to this, re-test the TR-SSV with an inflow test.
 - d) The flapper of the TR-SSV will always cut the slickline. Re-establishing control line pressure will not help. We can lock the TR-SSV open and fish for the remainder of the wire and the tool string
13. While pulling out of the hole with braided line, there is a sudden and unexpected increase in pulling weight. What is the most likely cause?
- a) There is a weight indicator error and this can be ignored
 - b) There is not enough lubrication grease on the cable
 - c) There are hydrates forming at the Grease Injection Head
 - d) There are broken strands on the braided line and we are therefore experiencing birdnesting at the Grease Injection Head





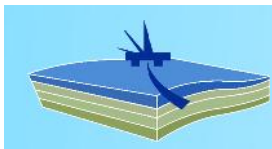
14. Under which operational conditions would we have to close a slickline BOP?
THREE ANSWERS
- a) When a cutter bar has to be dropped
 - b) When a leaking stuffing box has to be repaired
 - c) When a tool string or running tools needs to be changed out between runs
 - d) When fished wire needs to be stripped and threaded through the stuffing box ready for recovery and spooling back on the slickline drum
 - e) When a leak is observed at the Adaptor Flange
15. A wireline bridge plug has been set in the completion string. Along with a BPV in the Tubing Hanger this will permit a repair on the Xmas Tree to be performed. However, the bridge plug fails the inflow test. What is the best action to take?
TWO ANSWERS
- a) If the leak is small, then continue as it will not affect the repair. We still have a BPV that is installed in the Tubing Hanger.
 - b) Set a second bridge plug above the first one and perform another inflow test. If successful, then continue with the operation as intended
 - c) Retrieve the bridge plug and repair or replace with a new one. Perform another inflow test. If successful, then continue with the operation as intended
 - d) Mill out the bridge plug. Then set a new bridge plug and perform another inflow test. If successful, then continue with the operation as intended
16. We are running braided line in a high pressure gas well. Between runs an inspection of the BOP seals reveals that the elastomer seals have small blisters. What is the most likely cause?
- a) Ageing and fatigue of the elastomer
 - b) The wells' [high] temperature
 - c) Explosive decompression
 - d) Highly corrosive well fluids
 - e) Grease used for sealing the dual braided BOPs
17. We are preparing e-line to perforate a high pressure gas well in underbalanced mode. The well has a TVD of 10,750 ft. Tubing is filled with 9.5 ppg completion fluid. After detonation we expect a maximum surface pressure of 5080 psi. The Xmas Tree is rated to 10,000 psi and the braided line BOP is rated to 5000 psi. What should we do next?
- a) Operations can go ahead. Immediately after perforating the zone, completion fluid will leak into the formation and pressures will drop well below 5000 psi
 - b) Operations can go ahead. We would only suspend the operations when the estimated surface pressure proves to be correct.
 - c) Operations can go ahead. The BOP is body tested to 10,000 psi. We therefore have a lot of margin left when comparing this to estimated surface pressure
 - d) Suspend operations and consult with the senior engineer in the office to plan the way forward





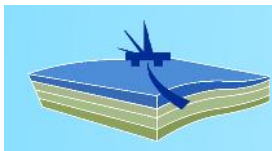
18. We are inspecting the braided wireline BOP and find that there is a serious cut on the upper end of the upper ram inner seal? What is the correct action to take?
- a) Replace the inner seal and pressure test the rams against a test rod
 - b) Cuts are very common. As long as there have been no leaks, continue with the operations
 - c) Pressure test the rams against a test rod. If okay, proceed as normal
 - d) Invert the ram so that the cut is on the lower end. This usually works well.
19. During a slickline job, the wire has parted and is blown out of the well. If the 'plunger' does not stop the leak, what would be the best closable barrier to use?
- a) Upper Master Gate Valve
 - b) Down Hole Safety Valve
 - c) Lower Master Gate Valve
 - d) Swab Valve
 - e) BOPs
20. On a wireline rig-up we find that the angle on the Hay Pulley, to which the weight sensor is connected, is 120° instead of 90°. Which of the following statements is correct about the weight indicator reading?
- a) It will read a higher value than the actual tension on the wire
 - b) It will read the same value than the actual tension on the wire
 - c) It will read a lower value than the actual tension on the wire
21. A slickline lubricator is fitted with a test sub. Which of the following statements is correct?
- a) A test sub can be used for retesting after a tool change, without testing the whole PCE rig-up, provided that only one connection above the BOP is broken for this tool change
 - b) A test sub eliminates the need to test the whole PCE rig up, when performing the initial test on this PCE
 - c) A test sub is not useful, because the lubricator is always tested against well pressure after a tool change
 - d) A test sub is commonly used as a barrier when the stuffing box requires a change of packing
22. During which type of wireline operations is a Safety Check Union used?
- a) Operations with slick wireline
 - b) Operations with braided wireline
 - c) Only in operations where a stuffing box is used





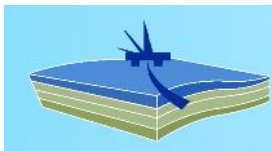
23. We are performing e-line work, but do not have a wire-cutting valve in the Xmas Tree. What should therefore be installed to provide a second closable barrier in case of a failure of the dual rams BOP, while there is e-line in the well?
- a) The dual rams BOP already functions as a double barrier
 - b) An additional BOP, dressed with Shear Rams
 - c) And additional dual rams BOP
 - d) An additional BOP, dressed with Shear/Seal Rams
24. A slickline BOP has been closed under pressure and with the tool string still in the well. The stuffing box needs to be repaired. What should be done before starting the repair work?
- a) Close the locking stems on the BOPs, bleed off the pressure above the BOPs and perform an inflow test
 - b) Bleed off the pressure above the BOPs and perform an inflow test
 - c) Connect to the test sub and pressure test the BOPs from above
 - d) Close the locking stems on the BOPs and bleed off the pressure above the BOPs
 - e) Connect to the pump-in sub and test the BOPs from below. Bleed off the pressure above the BOPs and perform an inflow test.
25. We intend to change over from slickline to braided line in order to perform a fishing job on parted slickline. What changes or additions to PCE are required?
THREE ANSWERS
- a) Add extra lubricator sections
 - b) Kill the well before doing making changes or adding PCE
 - c) Add a dual rams BOP and Grease Injector Head to the existing slickline BOP
 - d) Replace the rams in the slickline BOP with braided line rams
 - e) Add a Shear/Seal BOP or Shear/Seal Ball Valve, capable of cutting braided line
26. A deep-set positive plug has been set prior work on a well. However, it fails to hold pressure during an inflow test. Which of the following actions could be taken?
TWO ANSWERS
- a) Rig up a coiled tubing unit and set a cement plug above the positive plug
 - b) Pull the positive plug. Then redress and rerun, followed by an inflow test
 - c) Run a back-up positive plug in a nipple higher up, provided the nipple is still below packer depth
 - d) If the leak during the inflow test is relatively small, then it is acceptable to proceed with the job in hand
 - e) Pressure test the positive plug from above. If the plug holds pressure, then it is acceptable to proceed with the job in hand





27. During slickline operations and pulling on the line with 90% of line tension rating, the stuffing box starts to leak, which over time is getting worse and eventually becoming unacceptable. The hydraulic packing is not reacting to changes in hydraulic pressure. What is the best action to take?
- a) Back-off tension and close the slickline BOPs. Bleed off the pressure above the BOPs and perform an inflow test. Then repair the stuffing box.
 - b) Pull the slickline out of the rope socket, pull the wire out of the well and then prepare to repair the stuffing box
 - c) Continue to pull out of the well and then prepare to repair the stuffing box
 - d) Ask permission to bullhead kill the well. Once done, prepare to repair the stuffing box.
 - e) Close the Upper Master Gate Valve to cut the wire. Pull back the parted wire and prepare to repair the stuffing box.
28. During a slickline job, what 'immediate' action should be taken if a small leak occurs in the hydraulically operated stuffing box and with a tool string in the well?
- a) Stop wire movement, then close the wireline BOP
 - b) Continue with the operations and meanwhile notify the supervisor
 - c) Stop wire movement, then close the shear ram, shear/seal or wire-cutting valve on the Xmas Tree
 - d) Increase sealing pressure to the hydraulically operated stuffing box
29. Which of the following circumstances would require the well to be killed, while running braided line?
- a) Tool string stuck across the Xmas Tree valves
 - b) A leak in the Grease Injection Head
 - c) A leak below the wire-cutting valve
 - d) A leak between the Grease Injection Head and the wireline BOPs
 - e) If we experience significant overpull which would limit any further pull on the braided line
30. While running braided line, the grease pump fails, grease pressure is lost and as a consequence gas leaks past the wire and stuffing box. The back-up grease pump is not functioning either. What is the best 'immediate' action to take?
- a) Close the dual ram BOPs and repair the grease supply system
 - b) Cut the braided wire with the Shear/Seal Ram, then shut in on the Tree and repair the grease supply system
 - c) Pull out of the well while controlling the leak at the stuffing box, then shut in on the Tree and repair the grease supply system
 - d) Stop wire movement, increase pressure on the stuffing box to control the leak, then close the dual ram BOPs and repair the grease supply system





31. You have noticed that the certification for the wireline BOPs will expire the following day. You have planned for a 5-day wireline operation. What should you do?
- a) Start with the operations, because the wireline BOP will only expire the following day
 - b) Start and complete the operations, if the wireline BOP can be tested successfully
 - c) Suspend the work. Arrange for another set of wireline BOPs with a certification valid throughout the operations
 - d) Start with the operations, provided we pressure test the wireline BOP on a daily basis
 - e) Work can be started, but arrange for another set of wireline BOPs with a certification valid throughout the operations. In this manner we can guarantee redundancy
32. What is the reason for a Mule Shoe Guide or Bell Guide to be tapered and bevelled?
- a) To hang off a wireline tool
 - b) To permit entry of tools into the PBR of a Liner
 - c) To minimize friction when a wireline tool is run in a deviated well
 - d) To avoid wireline tools getting stuck when they enter the tubing, as some wireline tools may may have a square shoulder
33. The completion string has multiple packers and multiple production zones. To selectively produce from the various individual zones, how should you place the SSDs with respect to opening the sliding sleeve?
- a) The 2 top SSD are to be in a jar-up position and the bottom SSD to be in a jar-down position
 - b) All SSDs are to be in a jar-down position
 - c) All SSDs are to be in a jar-up position
 - d) The 2 top SSD are to be in a jar-down position and the bottom SSD to be in a jar-up position
34. Dual slickline BOPs are being used on a job. After some runs made in the well you notice some severe cuts on the packer element of the upper BOP. What should you do?
- a) Continue operations, you still have the lower slickline BOP.
 - b) Pressure test the dual slickline BOPs; if successful, then continue operations
 - c) Suspend the work. Redress the upper slickline BOP with a new packer element. Pressure test and if successful, continue operations.
 - d) Replace the upper BOP rams with those of the lower BOP rams. Only then can we continue the operations, because we must always use the upper BOPs first



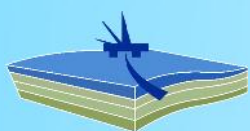


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IWCF Well Intervention
Well Control WORKBOOK

LEVEL 3/4





WORKBOOK WIRE LINE EQUIPMENT – ANSWER KEYS

EXERCISE WIRE LINE EQUIPMENT-1

1.	Primary Barrier: Stuffing Box [including Plunger] + Lubricator Sections
	Secondary Barrier: Wire Line BOPs [Blind Rams]
	Tertiary Barrier: Upper Master Valve [provided it can cut the wire]
2.	b
3.	a
4.	c
5.	b
6.	c
7.	c
8.	d, e
9.	d
10.	a, b, e
11.	c
12.	b, d, e
13.	b
14.	b
15.	b
16.	d
17.	a, d
18.	a
19.	b, c
20.	a, c

EXERCISE WIRE LINE EQUIPMENT-2

1.	b, d
2.	b
3.	c
4.	a, c, e
5.	c, d, f
6.	b
7.	a, c
8.	c
9.	b
10.	a





11.	a
12.	a
13.	b
14.	b
15.	a
16.	a
17a.	Primary Barrier: Stuffing Box [including Plunger] + Lubricator Sections
17b.	Secondary Barrier: Wire Line BOPs [Blind Rams]
17c.	Tertiary Barrier: Upper Master Valve [provided it can cut the wire]
18.	c
19a.	Primary Barrier: Grease Injection Head [GIH]
19b.	Secondary Barrier: Dual BOPs with Inverted Rams [for Braided/e-Line]
19c.	Tertiary Barrier: Shear/Seal BOPs [as a Single BOP above Xmas Tree]
20.	a
21.	a

EXERCISE WIRE LINE EQUIPMENT-3

1.	b
2.	c, d, f
3.	d, e
4.	c
5.	b
6.	b
7.	b, e
8.	c
9.	a, c
10.	a
11.	b, c





EXERCISE WIRE LINE EQUIPMENT-4

1.	c
2.	a
3.	b, d
4.	c, e, g
5.	c, e
6.	a
7.	c
8.	a
9.	b
10.	a, b, d
11.	a
12.	b
13.	c
14.	b
15.	b
16.	a, e
17.	b
18.	b
19.	c
20.	b
21.	b
22.	b
23.	a
24.	a



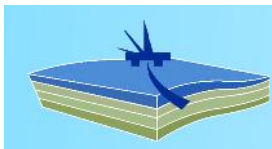


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COILED TUBING EQUIPMENT

EXERCISE COILED TUBING EQUIPMENT 1

1. Which factors affect the structural integrity of Coiled Tubing? (THREE ANSWERS)
 - a) The numbers of times the coiled tubing is run
 - b) The bending cycles of coiled tubing
 - c) The gooseneck radius
 - d) The bottom hole pressure
 - e) The chain tension at the injector head

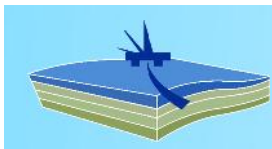
2. Statement is made that Slip Rams are designed to contain well bore pressure?
 - a) True
 - b) False

3. How is coiled tubing run in and out of the well?
 - a) Spooled on or off a reel using hydraulic power
 - b) Raised and lowered with an arrangement of sheaves supported by a telescoping gin pole
 - c) The coil is moved up and down the hole by means of Injector Head traction
 - d) Skates are fitted onto the reel to provide gripping friction

4. What is the main purpose of installing a Shear Seal BOP (Safety Head) on CT rig up?
 - a) To replace a Quad or Combi BOP if there are none available
 - b) To provide additional shear and seal capacity
 - c) To shear the CT but not seal the well
 - d) To seal the well effectively if closed around the CT

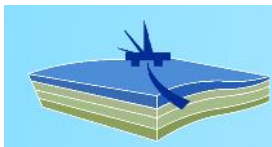
5. Which type of Stripper raises a major concern on buckling of CT?
 - a) Side Door Stripper
 - b) Conventional Stripper
 - c) Radial Stripper



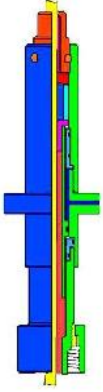
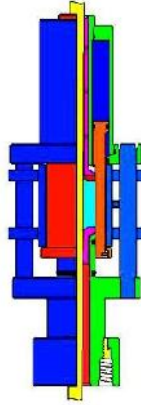


6. In typical Coiled Tubing operations, when and where do the highest bending stresses occur?
- a) Between the reel and the goose neck when RIH
 - b) At the mechanical footage counter, regardless of operation
 - c) Below the Injector Head when POOH
 - d) At the goose neck when POOH
7. On a coiled tubing unit, what is a Stripper often referred to?
- a) The 'Annular'
 - b) The 'Pack-Off Tool'
 - c) The 'Stuffing Box'
 - d) None of the above
8. The statement is made that all types of CT Strippers are well bore pressure assisted.
- a) True
 - b) False
9. The Quad BOP is commonly used in coiled tubing jobs. What is the recommended arrangement in this type of BOP, from top to bottom?
- a) Blind, Shear, Slip, Pipe
 - b) Pipe, Slip, Shear, Blind
 - c) Blind, Flow Tee, Shear, Slip
 - d) Slip, Pipe, Shear, Blind
10. Two advantages of using CT for remedial work are (a) the ability to work on live wells and (b) the ability to circulate while running in and pulling out of the hole. Which is the one main disadvantage associated with the above advantages?
- a) The pressure limits as a result of BOP rated working pressure of BOP
 - b) The high volume/low pressure pumps used on these CT units
 - c) The Injector Head may not be able to overcome the highest well pressure
 - d) Relatively low pumping rates due to the high friction created when pumping through a small diameter tubing





11. From the drawings below, describe the process of how the Stripper is energized?

	
Stripper Type: How to energize:	Stripper Type: How to energize:

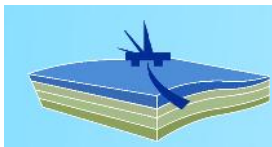
12. Why should the Chain Tensioner be adjusted during running coiled tubing?

- a) To maintain a secure gripping force on the CT while minimizing tubing damage and preventing slippage
- b) To ensure the CT will be centralized when required to close the pipe ram
- c) To avoid the chain from buckling when snubbing CT through the Injector Head
- d) To ensure the CT is able to lubricate with ease through the Stripper

13. If coiled tubing size is to be changed from 2-7/8" to 2" OD. What changes in the BOP stack have to be carried out? [TWO ANSWERS]

- a) All Rams have to be changed
- b) Pipe Rams have to be changed
- c) Slip Rams have to be changed
- d) Blind Rams have to be changed





EXERCISE COILED TUBING EQUIPMENT 2

1. Below is a coiled tubing motor assembly. We decided to include a circulating sub, to ensure we can circulate above the motor when so required. List the assembly you would run, from top to bottom, starting with the CT Connector.

1. _____
2. _____
3. _____
4. _____
5. _____
6. _____



NOTE: Do NOT mention the individual parts of the Motor i

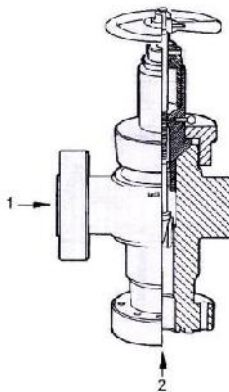
2. What do we mean when we talk about a 7-1/16" by 10,000 psi API-Flange?

Answer: _____

3. A coiled tubing rig up includes a choke line and choke manifold. There are two choke line gate valves before [upstream of] the choke. One is a hydraulically controlled and another one is manually operated. On which side should the manually operated valve be positioned?

Answer: _____

4. Below is a typical adjustable choke on coiled tubing rig up.

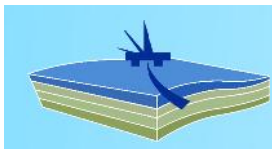


Match the number with the correct designation below.

INLET _____

OUTLET _____





5. What pressure does the manufacturer use to test the body [not the rams!] of a new 15,000 psi working pressure BOP?

Answer: _____

6. Coiled Tubing Barrier Principle:
Name the correct barrier for coiled tubing operations, both for external and internal pipe pressure controls: -

	External Pipe Pressure Control	Internal Pipe Pressure Control
▪ Primary Barrier	_____	_____
▪ Secondary Barrier	_____	_____
▪ Tertiary Barrier	_____	_____

7. What is the critical advantage that the flapper type of check valve has over the ball and seat type of check valve?

- a) Flapper valve closes faster
- b) Flapper valve requires less maintenance
- c) Ball, plug and dart can be pumped through them to activate other tools in the BHA
- d) Flapper valve has a higher rated working pressure

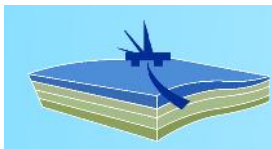
8. Which of the following may be indications that the CT has parted in the well? (TWO ANSWERS)

- a) Inside chain tension changes
- b) Choke pressure will increase
- c) Pump pressure shows a change
- d) Weight indicator shows a change
- e) Stripper pressure shows a change

9. With the CT across the X/mas tree in a high pressure-live well, the CT parts between the reel and the gooseneck. The check valves do not seem to hold pressure. Which of the following actions would then be the most appropriate to take immediately?

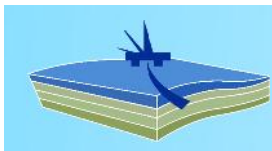
- a) Observe the flow first and evacuate all non-essential personnel from the worksite.
- b) Kill the well by bull heading down the CT annulus.
- c) Cut the CT using the Shear/Seal BOP.
- d) Phone the company man for approval to close the BOPs.





10. With coiled tubing in the hole, it is observed that the connection between the Quad BOP and the Stripper is leaking. Which secondary barrier must be closed to allow the leak to be repaired?
- a) Blind Ram
 - b) Pipe Ram
 - c) Swab valve
 - d) Upper Master Valve
 - e) DHSV
11. What are the advantages of a Combi-BOP in CT operations? (THREE ANSWERS)
- a) It reduces the stack height
 - b) It is more flexible than any other BOP
 - c) It is easier to activate the functions
 - d) It minimizes the steps for BOP operations
 - e) It is no longer necessary to use Shear/Seal [Safety Head] on the Xmas Tree
12. If a small but deep crack is found in the body of a CT BOP, which is brand new and has never been used before, what should we do?
- a) It is OK. It can be used some time longer since it is a brand new BOP.
 - b) Change the ram assembly before continuing with the operations.
 - c) Contact the OEM to perform a repair and then re-certificate it before use.
13. If during CT operations a leak occurs across the riser connection but below the shear rams of the Quad BOP, which one of the following is correct action?
- a) Close the Annular BOP
 - b) Close the SCSSV
 - c) Pick up CT +/- 10 ft and shear the tubing with the Shear/Seal BOP
 - d) Close the Swab Valve
14. We are using CT to clean out the well using inhibited seawater. A pin hole is detected on the CT between the gooseneck and reel level wind. What should we do to secure the well in a safe manner and bring it back to normal condition?
- a) Run in the CT until pinhole is below stripper but above BOPs, confirm BPVs are holding, then close the BOP Rams, lock and inflow test. Review situation.
 - b) Stop CT, stop pump, remove non-essential personnel from that area
 - c) If leak is getting worse by the minute, stop pump, POOH with CT until pinhole is located back on CT reel and repair CT with tube-to-tube connector
 - d) Run in the CT until pinhole is inside the stripper, close the Shear/Seal BOP





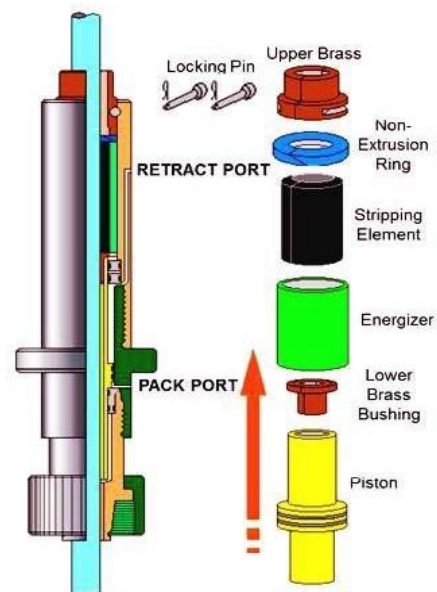
15. What is the best description of a 'CT Deployment System'?

- a) It is a means of running or feeding a very long BHA into the live well.
- b) It is a means of running or feeding a very long BHA into the Injector Head.

16. Where is the correct location of an adjustable choke on coiled tubing rig up?

- a) Where the fluid exits the completion/casing annulus
- b) Where the fluid exits the completion/tubing annulus

17. Have a look at the drawing:



How is this 'STRIPPER' energized?

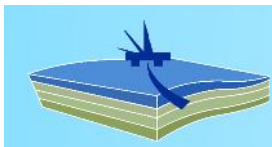
- a) Hydraulic pressure is applied to the lower bushing and this compresses the packing upwards.
- b) Hydraulic pressure is applied to the upper bushing and this compresses the packing downwards.
- c) Well head pressure will pack the packer without any assistance of hydraulic pressure.
- d) Hydraulic pressure is applied to the well head pressure port and this compresses the packing upwards

18. Have a look at the drawing:



How is this 'STRIPPER' energized?

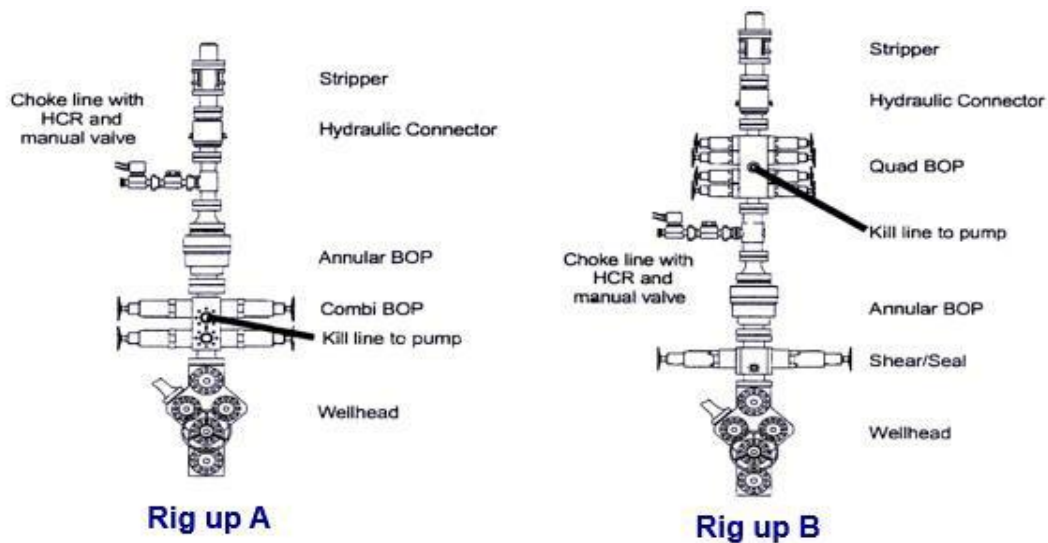
- a) Hydraulic pressure is applied to the lower bushing and this compresses the packing upwards.
- b) Hydraulic pressure is applied to the upper bushing and this compresses the packing downwards.
- c) Well head pressure will pack the packer without any assistance of hydraulic pressure.
- d) Hydraulic pressure is applied to the well head pressure port and this compresses the packing upwards



19. Have a look at the drawing:

If the choke line valves are leaking, which rig up will allow you to have two barriers closed while repairing the leak with coiled tubing in the hole?

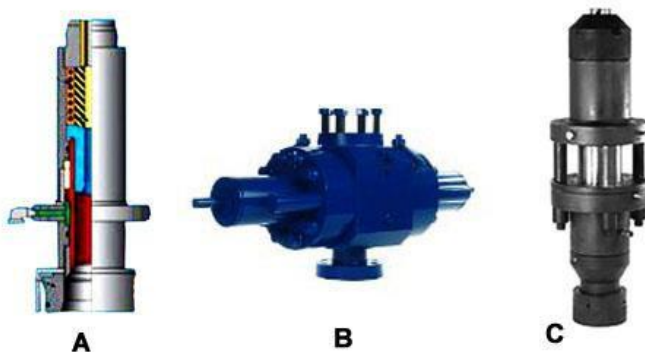
- a) Rig up A
- b) Rig up B



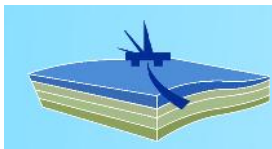
20. Referring to Question 19, if the stripper elements are worn out and need to be changed, which rig up would allow you to secure the well with two barriers closed while changing the strippers:

- a) Rig up A
- b) Rig up B
- c) Both

21. Have a look at the drawing. Name the type of CT Stripper as shown in the pictures:



- A. _____
- B. _____
- C. _____



EXERCISE COILED TUBING EQUIPMENT 3

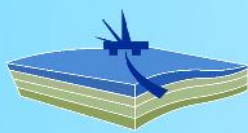
1. Which of the following statements about reverse circulation are true when working with coiled tubing? (TWO ANSWERS)
 - a) Reverse circulation is used whenever we have a mudmotor/bit combination.
 - b) Reverse circulation will lift the solids out of the tubing with more ease
 - c) Reverse circulation cannot be used when we use normal type of BPVs
 - d) Reverse circulation will create lower bottom hole pressures
 - e) Reverse circulation is only used when the CT is stuck

2. Which of the following statement is correct regarding the location of hydraulically operated and manually operated valves on short equalizing and bleed off lines, and the choke line that is routed to the choke manifold?
 - a) Manual Valve inside, Hydraulic Valve (HCR) outside
 - b) Hydraulic Valve (HCR) inside, Manual Valve outside
 - c) Hydraulic Valve (HCR) inside, Check Valve in the center, Manual Valve outside
 - d) Manual Valve inside, Check Valve in the center, Hydraulic Valve (HCR) outside

3. What essential precautions should be taken when stripping through an annular BOP? (TWO ANSWERS)
 - a) Have the BHA tool diagram available
 - b) Closely monitor the annular BOP pressure and weight indicator
 - c) Lubricate the tubing
 - d) Have a spare Annular Packing available
 - e) Set the Stripper in 'retract' mode

4. How do we commonly test the BPVs installed on the bottom of a coiled tubing BHA?
 - a) By pumping through the CT and pressure up from below
 - b) By using a straight bar with the Pipe Rams closed
 - c) By inflow testing after testing the Pipe Rams
 - d) By pumping through the kill wing on the Xmas tree





5. In the figure below, how does this stripper energize and seal well pressure when run coiled tubing into the well under pressure?



- a) Hydraulic pressure to wellhead port compress packing upward
- b) Wellhead pressure will pack off the stripper without hydraulic pressure
- c) Hydraulic pressure to wellhead port compress packing downwards
- d) Hydraulic pressure applied to the lower bushing compress packing upwards
- e) Hydraulic pressure applied to the upper bushing compress packing downwards

6. Does well pressure, if increased, helps to assist the sealing effect of the packing element inside the Side Door Stripper?

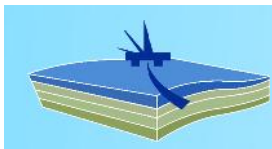
- a) YES
- b) NO

7. What happens when this stripper, in the figure below, is activated?



- a) Hydraulic pressure is applied to the lower bushing, which compresses the packer in an upward direction
- b) Hydraulic pressure is applied to the upper bushing, which compresses the packer in a downward direction
- c) Well pressure will activate/pack the stripper without the aid of hydraulic pressure
- d) Hydraulic pressure is applied to the wellhead pressure port, which compresses the packer in an upward direction





EXERCISE COILED TUBING EQUIPMENT 4

1. During a CT operation, the surface equipment leaks from the connection between the Quad BOP and the Stripper. Which barrier must be closed to make the well safe and allow the leak to be repaired?
 - a) Blind Ram
 - b) DHSV
 - c) Upper master valve
 - d) Pipe Ram

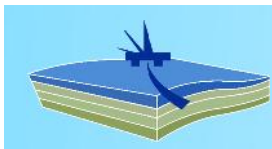
2. Which of the following statement is true?
 - a) The blind/shear or cutting ram is designed to cut the pipe and any BHA components.
 - b) The blind/shear or cutting ram is designed to cut the pipe only, not to cut the BHA.
 - c) The cutting action of the blind/shear or cutting ram is assisted by well bore pressure.
 - d) The blind/shear or cutting ram is operated with 5,000 psi hydraulic pressure.

3. When do we need to install an Annular Preventer?
 - a) When the stripper assembly is not available
 - b) When need extra security for high pressure operation
 - c) When need to seal around tools which have different ODs than the CT
 - d) When we strip the CT into the well under pressure

4. To deploy a BOP with 10,000 psi rated working pressure for the first time, we must conduct a 'body' test [also called 'shell test']. This done at the manufacturer's plant. To which pressure would this body test be carried out?
 - a) 15,000 psi
 - b) 20,000 psi
 - c) 10,000 psi

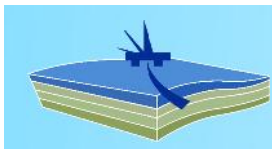
5. What is the best description of a CT deployment system?
 - a) It is the frame that supports the weight of the injector head
 - b) It is the action of feeding a long BHA through the injector head
 - c) It is mean of running a very long BHA into a live well
 - d) It supports the weight of the injector head and stripper when running coiled tubing on the floater





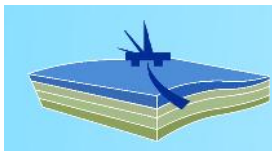
6. Coiled tubing is used for a reverse circulation operation in a live well by dropping a ball to open a circulation sub above the check valve. Which of the following statement is true when pulling out the coiled tubing?
- a) The coiled tubing can be pulled as long as the check valves were tested and are still holding pressure
 - b) While pulling out the CT and to maintain pressure in the coil, the valve on the reel will have to be closed
 - c) Continue with the reverse circulation to maintain adequate internal pressure control in the coil
 - d) While pulling out there will be no mechanical barriers at the bottom of the coil to prevent well bore fluids entering the coil
7. What gas is used to pre-charge the accumulator bottles used for the BOP Hydraulic Control System
- a) Nitrogen
 - b) Air
 - c) Oxygen
 - d) Carbon Dioxide
8. Why is a 'Flapper Type Check Valve' preferred over 'Ball and Seat Type of Check Valve' for most coiled tubing operations?
- a) Flapper Type Check Valves require less maintenance
 - b) Flapper Type Check Valves allow balls, plugs or darts to be pumped through them
 - c) Flapper Type Check Valves can withstand more pressure
 - d) Flapper Type Check Valves will close faster
9. How do we test the Pipe Ram of the Quad BOP?
- a) Pipe Rams must be tested from below using the kill wing connection
 - b) Pipe Rams must be tested by using the kill connection on the Quad BOP
 - c) Pipe Rams must be tested by pumping through the coil
 - d) Pipe Rams must be tested before rigging up with a 'straight bar'
10. What is the purpose of having a Check Valve installed in the CT BHA?
- a) It ensures that the coil will not collapse if exposed to high annular differential pressure
 - b) It ensures that pressure control can be maintained even if the CT fails at surface.
 - c) It ensures that BHA will not be exposed to any pressure.
 - d) It reduces the number of pressures test, because with a Check Valve it is no longer necessary to pressure test the CT itself.





- 11.** What are the main factors that have an effects on the fatigue life and therefore on the integrity of a coil? (THREE ANSWERS)
- a) The numbers of times the coiled tubing is run and pulled out
 - b) The BHP creating high pressure differentials across the coil
 - c) The radius of the gooseneck
 - d) The chain tension at the Injector
 - e) The bending cycles of the coil over gooseneck and reel
- 12.** What are the main advantages of a 'Combi' BOP over that of a 'Quad' BOP? (THREE ANSWERS)
- a) A Combi BOP reduces the height of stack
 - b) A Combi BOP creates more flexibility in the use of the stack
 - c) A Combi BOP minimizes the number steps to operate the BOP
 - d) A Combi BOP is easier to use
 - e) A Combi BOP is lighter in weight
- 13.** What is the Tertiary Barrier when we have a CT BOP Stack rigged up on a well on a high pressure well?
- a) Xmas Tree Valves
 - b) Shear and Blind Rams in a Quad or Combi BOP
 - c) Shear/Seal BOP [Safety Head]
 - d) Hydraulic Disconnect
- 14.** During coiled tubing operation, a leak is observed at the connection between Shear/Seal BOP and Xmas tree. What is the correct action?
- a) Close the Annular Preventer
 - b) Close the Swab Valve on the Xmas Tree
 - c) Close SC-SSV
 - d) Pick up about +/- 10 ft and shear the CT. Then close the Swab Valve
- 15.** While pulling the CT out of hole in a high pressure well, it is thought that we have a pinhole on the coil somewhere between surface and the BPVs. What is the best course of action?
- a) Continue pulling out at increased speed, regardless of the leak
 - b) Keep the string moving up and down to prevent it from getting stuck
 - c) Call the well supervisor or company man and agree on a meeting time.
 - d) Confirm BPVs are holding. Estimate leak point. Consider to kill the well.
 - e) Bleed down the internal pressure of coiled tubing to zero in safe manner, then continue pulling out.





END-OF-COURSE PAPER COILED TUBING EQUIPMENT 5

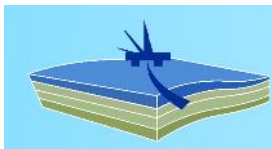
1. We experience a severe leak below the Shear/Seal BOP with the Coiled Tubing at a depth of 12,000 ft. What action[s] should we take?
 - a) Close the Slip and Pipe Rams and then kill the well
 - b) Close the Annular BOP and then kill the well
 - c) Close the Down Hole Safety Valve
 - d) Pick up 10 to 20 ft, operate the Shear/Seal BOP and then close the Upper Master Gate Valve on the Xmas Tree

2. During a BOP test, we observe fluid coming from one of the the weep holes on the Quad BOPs. What action[s] should we take?
 - a) One or more ram shaft seals are leaking. This BOP should be repaired or replaced and then retested before proceeding with CT operations
 - b) It seems a plug is missing. Obtain the appropriate manufacturer's threaded plug, close the weep hole and re-test the BOPs
 - c) No action is required. If the hydraulic system cannot maintain pressure, we can lock the rams instead, which will prevent any leakage from the rams
 - d) One or more ram shaft seals are leaking. Energize the emergency seal by squeezing plastic. Re-test the BOP before proceeding with CT operations

3. What is the purpose of a deployment system?
 - a) To run and retrieve a long BHA into the well in section, while the well is under pressure
 - b) To inject the Coiled Tubing into the well
 - c) This is another term used for the mobilization of the Coiled Tubing Unit to the assigned location
 - d) To provide a [extra] long lubricator for a long Bottom Hole Assembly

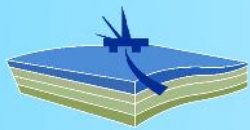
4. In which of the following situations would the Shear Ram of the Quad or Combi BOP be capable of shearing the items across the BOP?
 - a) The Bottom Hole Assembly and any other components we intend to run
 - b) The Coiled Tubing we intend to run along with any wireline that may be run inside it
 - c) The Coiled Tubing we intend to run
 - d) The Coiled Tubing we intend to run along with any perforation gun that may be suspended below it



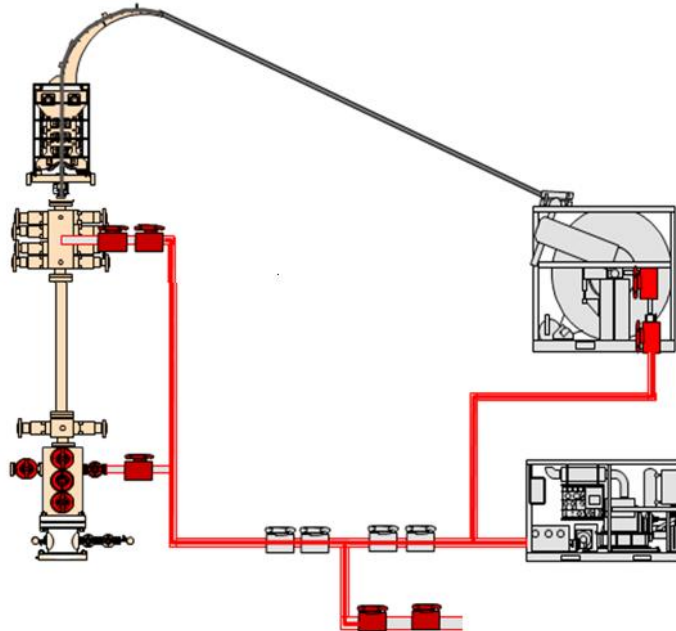


5. When would it be necessary to change Pipe Rams?
TWO ANSWERS
- a) When rigging up on a new and different well
 - b) When changing Coiled Tubing size
 - c) When the Pipe Rams are damaged, worn or do not hold pressure
 - d) When the elastomers change colour
 - e) Six-monthly
6. Why is it important to have the traction on the Injector Head set correctly?
TWO ANSWERS
- a) To ensure that the Coiled Tubing does not buckle
 - b) To ensure that the coil is not forced out of the well
 - c) To ensure that the Coiled Tubing is gripped properly, without causing damage as a result of slippage
 - d) To ensure that chain tension is correct
7. We have rigging up all of the Coiled Tubing Unit equipment, such as BOPs, riser and flow tee with kill and choke line. There are two valves on the choke line, one manually operated and hydraulically operated. According to API, where should the manual valve be located.
- a) Inside
 - b) Outside
8. We want to pump a ball down the coil to disconnect the Bottom Hole Assembly [BHA] at the BOSS [Ball Operated Separation Sub]. What kind of equipment is used to insert this ball?
- a) We do not drop a ball. Instead we use a ball carrier, which is fitted as part of the Bottom Hole Assembly before running the coil in the well
 - b) End of coil is disconnected from the low-torque valve situated at the centre of the reel and then the ball is dropped inside the coil before reconnecting the low-torque valve
 - c) A ball-injector is used, commonly rigged up between the reel swivel and the coil on the reel
 - d) Disconnecting the coil from the BHA is not possible by using a ball. It will not pass the check valves. Instead we use a hydraulic or tension disconnect.
9. We are using a Side Door Stripper and the Stripper Rubber is hydraulically energized. If the well pressure increases over time, will this also increase assist in energizing and sealing the Stripper Rubber on the coil?
- a) Yes
 - b) No



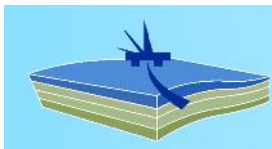


10. Coiled Tubing has been rigged up on a live well. There are lines from the pump connected to the Kill Wing of the Xmas Tree, to the Quad BOP and also to the Reel?



- A. The Blind Rams and Safety Head [Shear/Seal] are to be tested from the correct direction and without Coiled Tubing across the Quad BOP. Through which connection should test pressure be applied?
- A1) Coiled Tubing Reel
 - A2) Quad BOP Kill Port
 - A3) Kill Wing on the Xmas Tree
- B. When pressure testing the Pipe Rams, how would this be done?
- B1) By pumping through the Kill Wing connection
 - B2) By pumping through the coil
 - B3) From below, with a straight bar across the Pipe Rams
 - B4) From below by pumping through the Quad BOP Kill Port
- C. When pressure testing the Coiled Tubing Check Valves, how would this be done?
- C1) Pump through the coil and pressure up against the Stripper or Pipe Ram. Bleed back the pressure in the coil within its collapse limit, and check for pressure increase in the coil
 - C2) Pump into the Quad BOP up to the rated BOP pressure against the Stripper or Pipe Rams with the coil open, and check for flow back from the coil
 - C3) Pump into the Kill Wing against the Stripper or Pipe Rams with the coil open and check for back flow from the coil





11. The Coiled Tubing is used for a sand clean-out on a live well. Returns are taken through the choke line and onwards to the separator. To which upstream and downstream connections should the adjustable choke be routed?

TWO ANSWERS

- a) The inlet to the reel
- b) The inlet to the separator
- c) The coil/completion annulus exit
- d) The completion/casing annulus exit

12. Which of the following would normally be closed to seal in order to change a worn Stripper Rubber with the Coiled Tubing still in the well and a Quad BOP in use?

TWO ANSWERS

- a) Slip Rams
- b) Pipe Rams
- c) Blind Rams
- d) Shear or Cutter Rams
- e) Shear/Seal BOP [Safety Head]

13. When rigging up Coiled Tubing on a well, which of the following statements are correct?

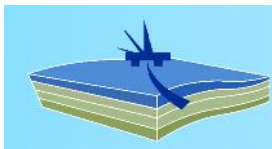
TWO ANSWERS

- a) A quick union that is made up hand tight only may cause a leak
- b) A damaged ring joint gasket may cause a leak
- c) A damaged 'O' ring or seal surface may cause a leak
- d) BOP locking stems not screwed in fully may cause the BOP Rams to leak

14. A ball has been dropped to open a circulating sub that is located just above the check valves. Reverse circulation can now be performed. If the well remains live, which of the following statements are correct?

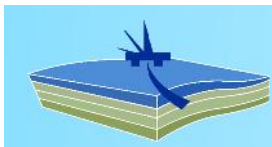
- a) While pulling out, the valve on the coiled tubing reel has to be closed to ensure we maintain proper internal well control
- b) The coil can be pulled out in a normal manner after the check valves have been tested successfully
- c) There will be no mechanical barriers at the bottom of the coil while pulling out
- d) To maintain proper well control, reverse circulation must be continued while pulling out





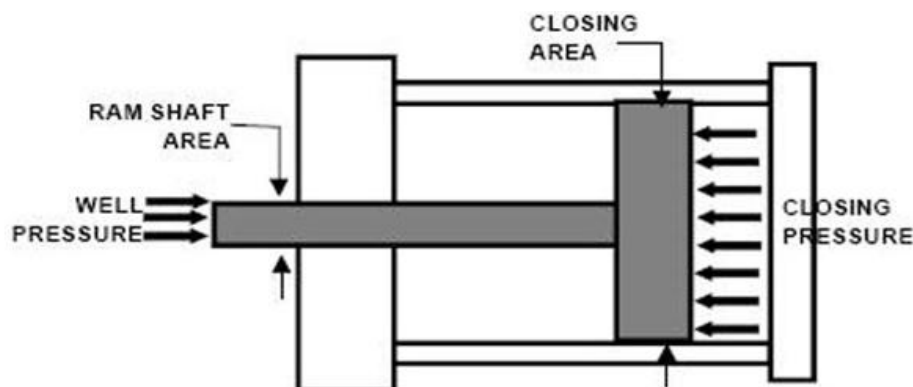
15. Of the three common types of stripper, which has the packing replaced through the top of the stripper?
- a) Conventional Stripper
 - b) Side Door Stripper
 - c) Radial Stripper
16. The Coiled Tubing has ruptured somewhere above the gooseneck and it appears that the Check Valves are not holding. Which of the following would be the most appropriate action?
- a) Kill the well by bullheading down the CT Annulus
 - b) Contact Operator's Representative and request for approval to close the BOPs
 - c) Observe the flow and evacuate all personnel from the worksite
 - d) Shear the Coiled Tubing and then seal open hole
17. What is the first action to take after connecting the BOP hydraulic hoses in preparation of BOP pressure testing?
- a) Function test the BOPs
 - b) Install the Injector Head
 - c) Open up the Xmas Tree Valves
 - d) Sign the handover document from production
18. What is the main reason for including an Annular Preventer in the rig up of a Coiled Tubing Unit?
- a) It is mandatory on high pressure wells
 - b) It permits closure around large diameter BHA items
 - c) It is the only way to strip Coiled Tubing into the well
 - d) It serves as a back-up in case of Stripper Rubber failure
19. What are the main advantages of a Combi BOP over that of a Quad BOP?
TWO ANSWERS
- a) A Combi BOP is shorter and requires less height between Xmas Tree and Injector Head
 - b) After cutting the Coiled Tubing, it will be much easier to pump kill fluid with a Combi BOP than with a Quad BOP
 - c) There are fewer steps to take in case of emergency when using a Combi BOP
 - d) After cutting the Coiled Tubing, it will be possible to pump down the annulus when using a Combi BOP and not with a Quad BOP
 - e) There will be less shearing force required when using a Combi BOP than when using a Quad BOP

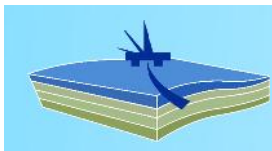




20. When using a Stripper, which of the following statements is a good definition of 'Well Pressure Assist'?
- a) The well pressure acting on the piston will produce an additional pressure in the closing chamber and therefore an additional closing force
 - b) The well pressure acting on the piston must be subtracted from the operating pressure in the closing chamber, resulting in a reduced force
 - c) The well pressure acting on the lower surface of the piston adds additional closing force to that of the hydraulic pack-off pressure
21. What is the main reason for having a 'weep hole' on a Ram Type BOP?
- a) To indicate that the Ram Body Seals are leaking
 - b) To indicate that the primary Ram Shaft Seals are leaking wellbore fluid or hydraulic operating fluid
 - c) To indicate that the bonnet seals are leaking
 - d) To indicate that pressure equalization above and below the BOP Rams has taken place and that the BOP Rams can be opened up
22. The Coiled Tubing is being used for a sand clean-out activity. We apply the reverse circulation method. Which of the following statements are true about reverse circulation?
- TWO ANSWERS
- a) Reverse circulation is only applied to prevent stuck coil situations
 - b) Reverse circulation cannot be applied when using regular Check Valves
 - c) Reverse circulation will lower the downhole pressures considerably
 - d) Reverse circulation will lift solids out of the well better, because the Tubing/CT annulus is usually greater than the CT capacity
 - e) Reverse circulation is applied when we have a mud motor in the BHA, because it has a suction effect that is able to clean out the sand very efficiently
23. What is the minimum hydraulic closing pressure required to close a ram with a 'closing ratio' of 9.80 : 1 and a wellbore pressure of 8,000 psi?

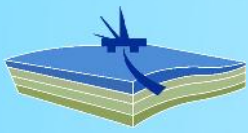
Answer: _____psi



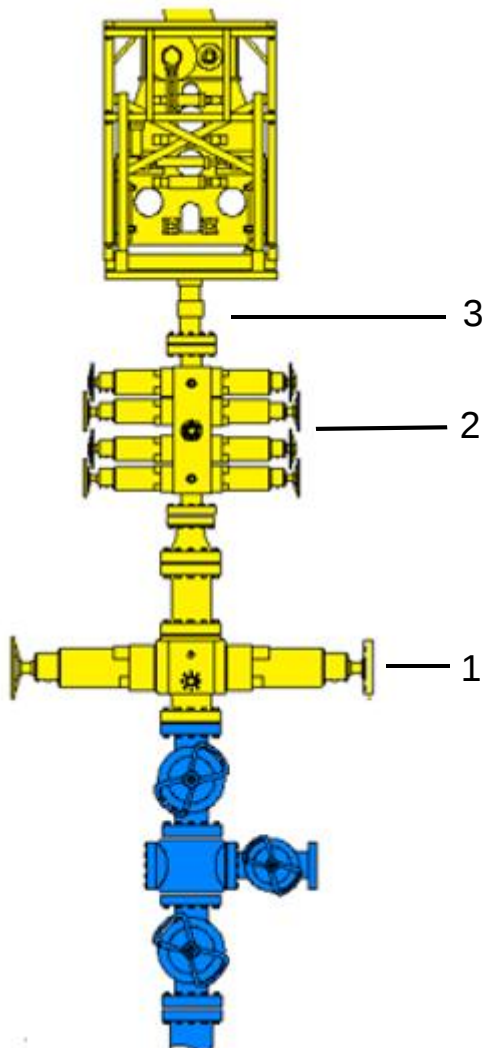


24. Of the 3 types of Strippers we commonly use, which Stripper requires the Stripper Rubber to be replaced from the top of the Stripper?
- a) Conventional Stripper
 - b) Side Door Stripper
 - c) Radial Stripper
25. What should be the first action to take if the Stripper starts to leak?
- a) Close the Slip Rams
 - b) Close the Pipe Rams
 - c) Increase the hydraulic pressure on the Stripper Rubber
 - d) Continue with the operation, but notify the Operator's Representative
26. Which of the following statements is true when we talk about Ram Type BOPs?
- a) It only seals pressure from below
 - b) It only seals pressure from above
 - c) It seals pressure from both directions
27. To what pressure is a 10,000 psi Coiled Tubing BOP body tested by the manufacturer before it can be put to use?
- a) 10,000 psi
 - b) 15,000 psi
 - c) 20,000 psi
 - d) 5,000 psi
28. Why do we install check valves to the bottom of the Coiled Tubing string?
- a) In order to prevent the Coiled Tubing from collapsing when exposed to differential pressures
 - b) In order to maintain pressure control if the Coiled Tubing starts to leak at surface
 - c) In order to ensure that the BHA is not exposed to pressure
 - d) To facilitate testing of the Quad BOP Pipe Rams



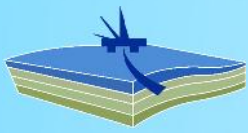


29. What is the correct order of BHA elements from bottom of Coiled Tubing string downwards to the Mill or Bit?
- a) Connector, Check Valve 1, Release Joint, Check Valve 2, Circulation Sub, MudMotor, Mill or Bit
 - b) Connector, Release Joint, Check Valve 1, Check Valve 2, Circulation Sub, MudMotor, Mill or Bit
 - c) Connector, Release Joint, Circulation Sub, Check Valve 1, Check Valve 2, MudMotor, Mill or Bit
 - d) Connector, Check Valve 1, Check Valve 2, Release Joint, Circulation Sub, MudMotor, Mill or Bit
30. Below is a schematic of a Coiled Tubing Stack rig-up. Match the correct number with barrier shown in the schematic.

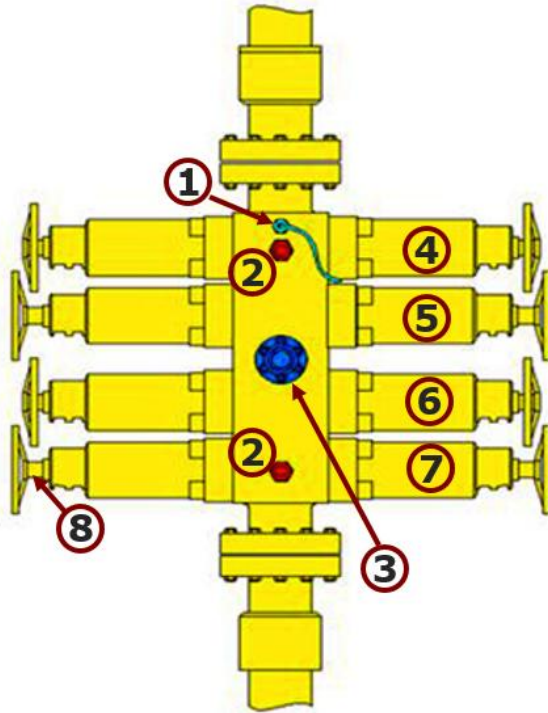


- a) Primary Barrier: _____
- b) Secondary Barrier: _____
- c) Tertiary Barrier: _____





31. Below is a schematic of a Quad BOP. Match the correct number with text on the right of the schematic.



- a) Shear Rams: _____
- b) Slip Rams: _____
- c) Pressure Sensor Port: _____
- d) Blind Rams: _____
- e) Equalizing Port/Valve: _____
- f) Pipe Rams: _____
- g) Ram Lock Stem: _____
- h) Kill Port: _____

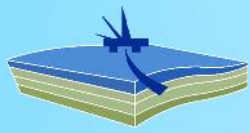
32. In Coiled Tubing BHAs, what is the main advantage of Flapper Type Check Valves over that of Ball & Seat Type Check Valves?

- a) Flapper Type Check Valves close much faster
- b) Flapper Type Check Valves require less maintenance
- c) Flapper Type Check Valves have a higher pressure rating
- d) Flapper Type Check Valves permit balls to be pumped through

33. What are the most important reasons for using Coiled Tubing BOPs?
TWO ANSWERS

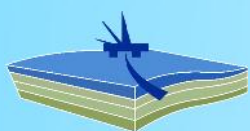
- a) To operate in safe manner and maintain well control
- b) To facilitate safe repair of everything that fails above the CT BOPs
- c) To supply a greater degree of protection compared to only Strippers
- d) To comply with the minimum requirements of API standards



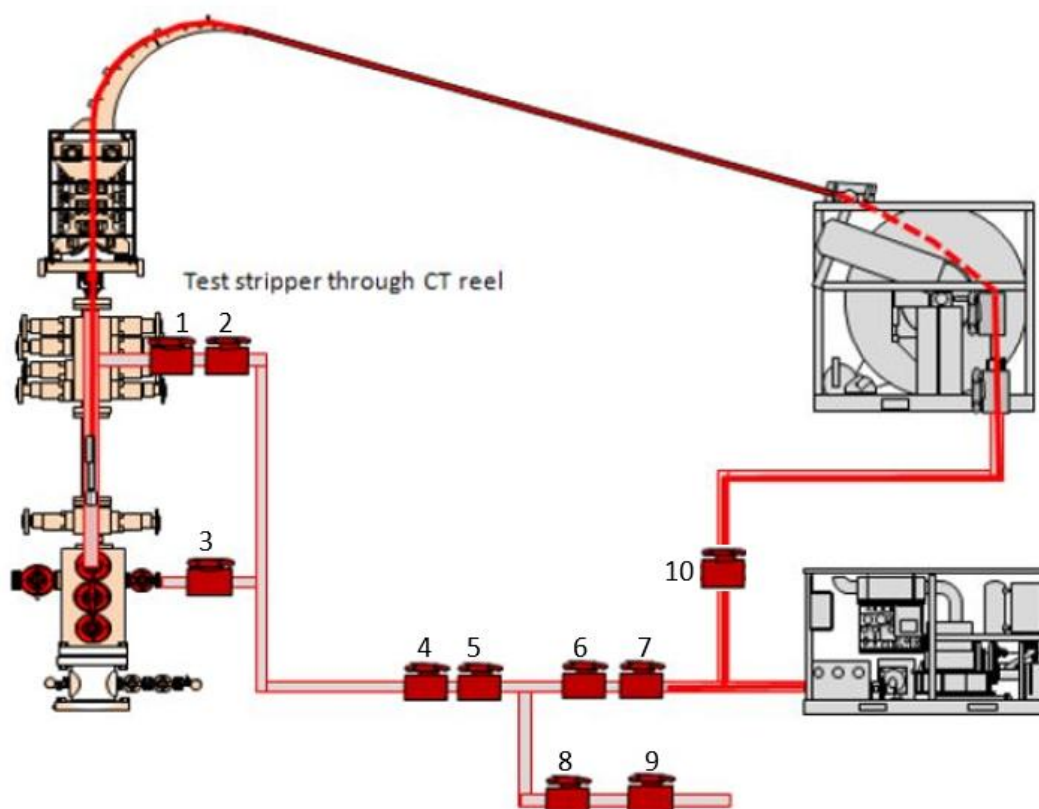


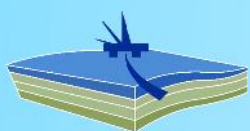
34. A Tandem Stripper is rigged up on Coiled Tubing well control equipment. While running Coiled Tubing in the hole, the Upper Stripper starts leaking, What should you do?
- a) Close Shear/Blind Rams, replace worn out Upper Stripper Rubber
 - b) Close Lower Stripper, replace worn out Upper Stripper Rubber
 - c) Close Lower Stripper, close Pipe Rams and inflow test, then replace Upper Stripper Rubber and pressure test
 - d) Pull out to surface, and then replace the worn-out Upper Stripper Rubber
35. You rigged up a Tandem Stripper on Coiled Tubing well control equipment. You close the Lower Stripper and Pipe Rams to change out the leaking Upper Stripper Rubber. How do you know if the Pipe Rams would hold pressure?
- a) Well fluid would run out from vent line between Lower Stripper and Pipe Rams
 - b) Pressure increase at Lower Stripper above the Pipe Rams
 - c) One can never tell if the Pipe Rams are leaking or not
 - d) Pressure test the Pipe Rams from above using the Kill Port
36. You have a pump-off sub at the end of the coiled tubing BHA. What do you need in order to release this pump-off sub?
- a) Pull approx. 10,000 plbs over free CT weight
 - b) Bleed off coiled tubing pressure before dropping the ball
 - c) Pump down the annulus and pressure up
 - d) Pump down the ball and pressure up
37. You want to rig up a flow tee on Coiled Tubing pressure control equipment. Where should you position the Shear/Seal BOP related to the flow tee?
- a) Shear/Seal BOP below the flow tee
 - b) Shear/Seal BOP above the flow tee
 - c) Shear/Seal BOP position is not important





38. You are planning a Coiled Tubing operation to clean up the well by pumping down the CT. Where should you position the adjustable choke to control bottom hole pressure?
- a) At the fluid exit between completion tubing and casing
 - b) At the fluid exit between coiled tubing and completion
 - c) At the inlet of the production separator
 - d) At the fluid inlet of the reel, next to the swivel
39. At the start of the pressure test sequence, all valves in the diagram below are in closed position. Which valve should be opened to pressure test the Stripper?
- a) Valve 10
 - b) Valve 3, 4, 5, 6 and 7
 - c) Valve 1, 2, 4, 5, 6 and 7
 - d) Valve 1, 2, 3, 4, 5, 6 and 7





WORKBOOK COILED TUBING EQUIPMENT – ANSWER KEYS

EXERCISE COILED TUBING EQUIPMENT- 1

1.	a, b, c
2.	b
3.	c
4.	b
5.	b
6.	d
7.	c
8.	b
9.	a
10.	d
11.	Stripper Type: Conventional Stripper How to energize: Hydraulic pressure and also well pressure (if increased) are applied to the lower bushing, compressing the Energizer <u>upwards</u>
	Stripper Type: Side Door Stripper How to energize: Hydraulic pressure is applied to the upper bushing, compressing the Energizer <u>downwards</u>
12.	c
13.	b, c

EXERCISE COILED TUBING EQUIPMENT- 2

1.1	CT Connector
1.2	Back Pressure Valve 1
1.3	Back Pressure Valve 2
1.4	Release Joint or Safety Valve
1.5	Circulating Sub enabling By-Pass Flow
1.6	Motor, Stabilizer, Bit
2.	Flange has 7-1/16" thru-bore and 10,000 psi working pressure rating
3.	On the upstream side, i.e. the first valve from the well
4.	INLET: 1 and OUTLET: 2
5.	22,500 psi
6.	Primary Barrier: <u>External</u> : Stripper & Annular + <u>Internal</u> : Dual Check Valves
	Secondary Barrier: <u>External</u> : BOPs [Safety Ram] + <u>Internal</u> : Cutter Ram [Shear Ram]
	Tertiary Barrier: <u>External</u> : Shear/Seal + <u>Internal</u> : Shear/Seal
7.	c
8.	c, d
9.	c





10.	b
11.	a, c, d
12.	c
13.	c
14.	a
15.	a
16.	b
17.	a
18.	b
19.	a
20.	c
21a.	Conventional Stripper
21b.	Radial Stripper
21c.	Side Door Stripper

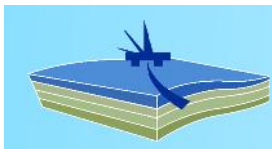
EXERCISE COILED TUBING EQUIPMENT-3

1.	b, c
2.	a
3.	a, b
4.	c
5.	e
6.	b
7.	a

EXERCISE COILED TUBING EQUIPMENT-4

1.	d
2.	b
3.	c
4.	a
5.	c
6.	d
7.	a
8.	b
9.	c
10.	b
11.	a, c, e
12.	a, c, d
13.	c
14.	d
15.	d





SNUBBING EQUIPMENT

EXERCISE SNUBBING EQUIPMENT 1

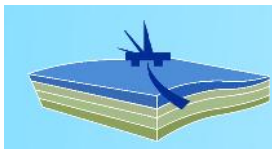
1. What do we mean when we use the term 'pipe light'?"
 - a) The pipe is run in or pulled out dry, and not filled with mud
 - b) The upward force that the well exerts is greater than the weight of the string at a given depth
 - c) The term refers to a lighter weight range of pipe
 - d) An upward force that the well exerts is less than the weight of the string at a given depth

2. Why would a manufacturer want to show that the maximum pressure on the stripper rubber is 3,000 psi?
 - a) If we work at higher well pressures, it may cause accelerated wear on the rubber seal
 - b) It is the highest rated working pressure that the manufacturer can provide
 - c) The stripper rubber is energized by the accumulator pressure of 3000 psi
 - d) The stripper rubber uses a regulated operating pressure of 1500 psi, but in emergencies this pressure can be as high as 3000 psi

3. The function of the guide tube on a snubbing unit is to:-
 - a) Prevent pipe buckling
 - b) Guide the pipe through the BOPs
 - c) Guide the jack pistons into the cylinders
 - d) Guide the pipe safely through the window

4. The stripper rubber, located at the base of the jack, is usually:-
 - a) A high pressure preventer (greater than 3,000 psi)
 - b) A modified ram assembly with stripping ram inserts
 - c) A rubber to lubricate the drill string before it passes the stripping rams
 - d) A low pressure preventer (less than 3000 psi)





5. What type of choke on the choke manifold is normally used to handle fluid returned from the well?
 - a) Adjustable type
 - b) Orifice type
 - c) Fixed bean type

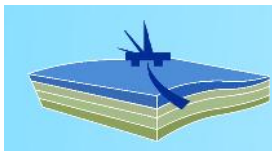
6. If the slips are set on a tool joint while operating in the 'pipe light' mode, which of the following may occur?
 - a) The work string may drop into the well
 - b) The work string may part just below the slips
 - c) The pipe could be forced out of the well
 - d) The work string may part just above the slips

7. What are the main two considerations when selecting the type of snubbing well control equipment to be used? (TWO ANSWERS)
 - a) Anticipated maximum surface pressure
 - b) Maximum depth of balance point between light and heavy pipe
 - c) Equipment needed to cope with emergencies and still maintain a barrier
 - d) Weight and type of kill fluid that may be used

8. Blind/Shear Rams are designed to cut the work string and seal off the well pressure. Which the following statement is correct?
 - a) It will usually not cut if a smaller sized work string is in the hole
 - b) It will usually not cut if there is tension on the work string
 - c) It will usually not cut if there is torsion on the work string
 - d) It will usually not cut if opposite a drill collar or drill pipe tool joint

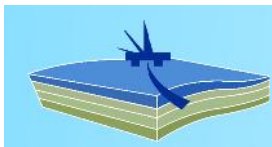
9. The BOP Hydraulic Control Unit (Accumulator Unit) has been rigged up. After connecting the hydraulic control lines to the BOPs, what is the first action to take after this?
 - a) Pre-charge the Accumulator with Nitrogen Gas
 - b) Function test all rams and valves on the BOP stack
 - c) Place all 3 position/4-way valves in a Block/Neutral position to allow regulated pressure to be applied to the hoses and checks for leaks
 - d) Get ready to pressure test all of the BOP rams





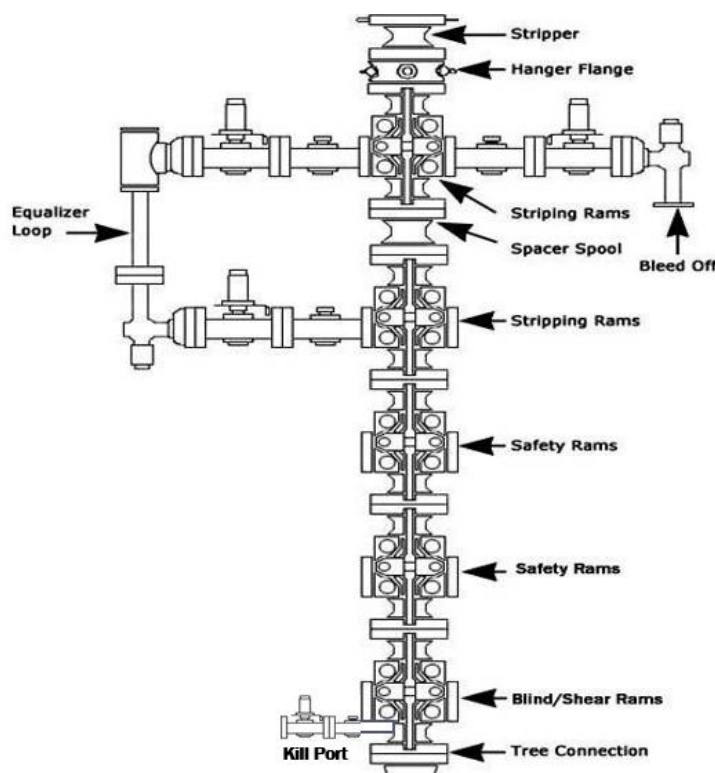
10. While running the work string into the hole, using the stripping rams as the primary barrier, it is found that one of the stripping rams is worn out badly and no longer holds pressure. What is the correct course of action?
- a) No choice, you must finish the job with the good stripping rams that are still available
 - b) You must stop, close available barriers and redress both stripping rams of this one set
 - c) You must stop, close available barriers and redress the worn stripping ram of this one set
 - d) If you have an Annular Preventer, you can continue the job, because the Annular Preventer can also be used as a primary barrier
11. What is the main reason for having Shear/Seal BOP (Safety Head) installed directly above Xmas Tree?
- a) In order to act as Safety Rams if the Blind Rams fails to seal
 - b) To ensure that the well can be shut in at the Xmas tree after the tool string has been cut and dropped down the well
 - c) In order to function as an emergency BOP in the event that the Xmas tree is not capable to cut the work string
 - d) In order to have access to the Safety Head in case the pressure needed to cut the work string appears to be inadequate
12. A leak occurs in the work string that has been run into the well. What is the very first action that must be taken?
- a) Rig up up a circulation hose and pump kill fluid down the work string
 - b) Use the Xmas tree kill wing and bullhead kill fluid into the annulus
 - c) Install a stabbing safety valve [FOSV] on the work string and close it
 - d) Drop a secondary wireline check valve in the work string.





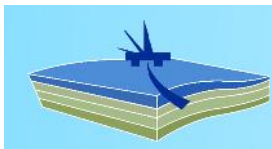
EXERCISE SNUBBING EQUIPMENT 2

1. If one of the Stripper Rams has worn out insert, can we change out this insert safely with pipe in hole?
 - a) Yes, because the Stripper Rams are located above the Safety Ram
 - b) Yes, because the Stripper Rams are located below the Safety Ram
 - c) Yes, because we can close the Xmas Tree valves
 - d) No, because the double check valves do not count as double barriers
2. The Snubbing unit is rigged up with surface pressure control equipment. Prior starting up the operation, the snubbing BOPs must be tested from the direction of flow. Which connection on the BOP stack should the test line be connected to?



- a) At the Equalizer Loop opposite the Stripper Rams
 - b) At the Spacer Spool between the two Stripper Rams
 - c) At the kill port below Blind/Shear (lower most connection above X/mas Tree)
 - d) At the test port that is specially made for this purpose on the Stripper [Rubber]
3. When is the largest snubbing force acting on the work string?
 - a) When the work string is going around a build-up section
 - b) When the first joint is going in the hole
 - c) When we cross the balance point
 - d) When we circulate with the BHA on bottom





4. Where is Stripper Bowl located on a standard Snubbing Rig Up?
 - a) Attached to the Telescoping Guide Tubes
 - b) Attached to the bottom of the Window
 - c) Attached to the top of the Window
 - d) Attached to the lower Stripper Rams

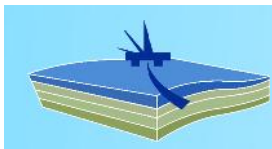
5. For a standard snubbing rig up configuration (Ram to Ram Snubbing), which mechanical barrier is the Primary barrier?
 - a) BOP rams
 - b) Stripping BOPs
 - c) Annular BOP
 - d) Shear/Seal BOP

6. What is the reason for installing the Shear/Seal BOP (Safety Head) immediately above X/mas Tree?
 - a) To ensure that we have easy access to the Shear/Seal BOP (Safety Head), in case we need to lock the BOP rams after shearing the pipe.
 - b) To ensure that any tool joint is spaced out some distance away from the Shear/Seal cutting blades.
 - c) To ensure that the open and close functions of the Shear/Seal BOP can become an integral part of the ESD production system on a location
 - d) To ensure that the drill pipe, which is run in the hole, can be cut successfully, after which we should be able close the X/Tree valve without an obstruction

7. Name components of a Snubbing Motor Assembly and arrange them in the proper order for from top to bottom.
 - a) BPV – BPV – Circulating Sub – Motor – Under Reamer (Stab) – Bit
 - b) BPV - Circulating Sub – BPV – Motor - Under Reamer (Stab) - Bit
 - c) Circulating Cub – BPV – BPV – Motor - Under Reamer (Stab) - Bit
 - d) Safety Sub – BPV – BPV - Circulating Sub – Motor - Under Reamer (Stab) – Bit

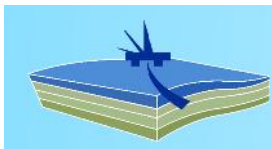
8. Is it a normal practice to change Safety Ram (Pipe Ram) inner seal during a job with pipe in the hole? (Yes or No and explain why)
 - a) No
 - b) Yes





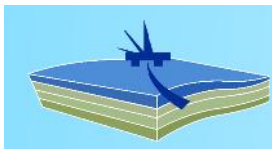
9. Can a Stripper Ram inner seal be changed out with a work string in the hole and the Safety Rams closed?
- a) Yes
 - b) No
10. It is the intention to run in with a tapered string, consisting of 1,000 ft of 1.900" OD pipe below a 2-3/8" OD pipe. The snubbing unit is rigged up on top of the X/mas tree. The SITHP is 3,500 psi and the fluid returning from the well is routed to the flow wing. Which of the following statements are true? (TWO ANSWERS)
- a) The Stripper Rubber will be the primary barrier during the intervention
 - b) The Annular BOP will be the primary barrier during the intervention
 - c) As a minimum two Safety Rams to be included in the BOP stack for both size of pipes
 - d) The Stripping Rams will be the primary barrier during the intervention
 - e) Either the Stripper Rubber or the Annular BOP will be the primary barrier during the intervention
11. A 2-3/8" workover string is to be run into the hole in order to wash sand out of the well. The snubbing unit has been rigged on top of the Xmas tree. The SITHP is 3,500 psi. Will it be possible to pump fluid through the work over string with return via the flow wing valve?
- a) Yes
 - b) No
12. What would be the recommended action to take when the bypass of the circulating valve above the mud motor assembly is stuck in open position?
- a) Kill the well and pull out of hole in the conventional manner
 - b) If check valves are holding pressure, snub out of hole to replace the circulating valve
 - c) Drop the Pump Down Plug and pump it into place
 - d) Install the Stabbing/Safety Valve and close it
13. What type of Choke is to be installed at the Short Equalizing Loop of the snubbing rig up?
- a) Fixed Bean or Positive Choke
 - b) Adjustable Choke





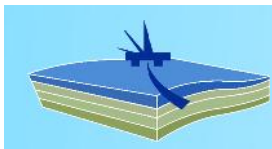
14. What type of Choke is to be installed at the Choke/Kill line manifold when fluid return from the well?
- a) Fixed Bean or Positive Choke
 - b) Adjustable Choke
15. When rigging up for snubbing, why would we want to have an adjustable choke on the return line to the choke manifold?
- a) To control the bottom hole pressure when performing a circulation
 - b) To bleed off pressure above the lower Stripper Ram
 - c) To bleed off pressure between upper Stripper Ram and Stripper Rubber
 - d) To bleed off pressure above the Stripper Rubber
16. What should be the position of the string safety valve before we stab it onto the work string and having string safety valve ready on the working basket?
- a) Close
 - b) Open
17. Do we always install the Equalizing Loop between the Upper and Lower Stripper Rams?
- a) Yes
 - b) No
18. What is the primary function of a Stripper Bowl Assembly?
- a) Primary well control device with low wellhead pressure work (primary barrier)
 - b) Secondary well control device with wellhead pressure work up to 3500 psi
 - c) To clean the pipe from oil residue when pulling out
 - d) To prevents debris from falling into the wellbore during tripping
 - e) To accommodate stripping of standard API tubing couplings
19. How can we calculate the surface pressure if both reservoir pressure and average well fluid gradient are accurately known?
- a) Calculate the hydrostatic pressure of fluid in the well and add this to the reservoir pressure from the well.
 - b) Calculate the hydrostatic pressure of fluid in the well and subtract this from the reservoir pressure from the well.
 - c) Calculate the average value of the sum of hydrostatic pressure of fluid in the well and reservoir pressure.
 - d) Calculate the hydrostatic pressure of fluid in the well and subtract this from the hydrostatic pressure of the kill fluid inside the work string.





20. During snubbing operation, it is observed that the Stripper Rubber starts to leak due to wear. What are the correct actions should be taken?
- a) Close stationary slips, Install Stabbing/Safety Valve and close it, close Safety Rams, inflow test same, change the Stripper Rubber, equalize pressure, open preventers and check for leaks past Stripper Rubber
 - b) Close stationary slips, Install Stabbing/Safety Valve and close it, close Annular Preventer and Lower Stripping Rams, inflow test both, change the Stripper Rubber, equalize pressure, open preventers and check for leaks past Stripper Rubber
 - c) Close stationary slips, Install Stabbing/Safety Valve and close it, kill the well and monitor for flow, change the Stripper Rubber, bring the well back into underbalance, check for leaks past Stripper Rubber and continue with operations
21. The statement is made that it is normal practice to replace the Annular Preventer Packer during a snubbing intervention operation?
- a) True
 - b) False
22. We want to calculate the depth at which the balance point between light pipe and heavy pipe will be reached. What is the essential information we need to make this calculation?
- ** Ignore friction through Stripping Rams and Stripper.
- a) Well Pressure [psi], Well Fluid Density [ppg], Weight of Work String [lb/ft]
 - b) Well Pressure [psi], Well Fluid Type, OD and ID of Work String [inch]
 - c) Well Fluid Density [ppg], OD of Work String [inch], Weight of Work String [lb/ft]
 - d) Well Pressure [psi], Well Fluid Density [ppg], OD of Work String [inch], Weight of Work String [lb/ft]





EXERCISE SNUBBING EQUIPMENT 3

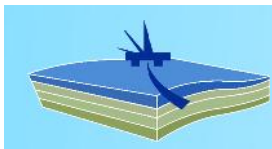
1. If one of the stationary or travelling slips is malfunctioning during a snubbing trip out of the hole, what are the actions required to continue a safe operation?
(FOUR ANSWERS)
 - a) Immediately set the back-up slips
 - b) Use the hand slips
 - c) Install a FOSV [keep open]
 - d) Close a stripping ram
 - e) Use the stripper bowl
 - f) Test the back-up slip by careful load transfer procedure
 - g) Use a safety clamp as a back-up

2. During a snubbing operation in 'Pipe Light' mode, which closed slip combination is correct?
 - a) Travelling snubbers and static snubbers
 - b) Travelling snubbers and static heavies
 - c) Travelling slips and static snubbers
 - d) Travelling slips and static heavies

3. The surface equipment is to be pressure tested and function tested after rigging up. Which statements give the best description on how the BPV's (check valves) on the BHA will be tested? (TWO ANSWERS)
 - a) Pipe held so that it cannot fall onto the swab valve
 - b) A closed FOSV must be placed on the work string
 - c) Pump down through the work string with safety rams closed to test the BPVs
 - d) Pumping through the stack from the kill line to test the BPVs
 - e) Work string must be held in position so that it cannot move up or down

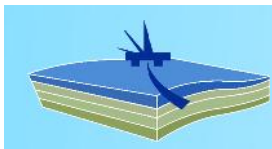
4. With the string in snubbing more and during a forward circulation, we experience a power failure on the pump. What is the correct procedure to return the well back to a safe condition?
 - a) For critical operations we should have 2 pumps, one of which will function as a back-up. Isolate the pump with a power failure and kick in the back up pump without delay.
 - b) For critical operations we should stop the operations, close the Pipe Rams, close the FOSV and request for a new pump.





5. During snubbing operation, the Stripper Rubber started to leak, because it had worn out badly and was in need of a change. Which of one the following procedures is correct?
- a) Close both Stripper Rams, Inflow Test, Change Stripper Rubber, Pressure Test
 - b) Close Stationary Slips, Close Safety Ram, Inflow test, Change Stripper Rubber
 - c) Close Annular BOP, Close Lower Stripper Ram, Inflow Test, Change Stripper Rubber
 - d) Close Stationary Slips, Close Annular BOP, Inflow Test, Change Stripper Rubber
6. Which BOPs are considered the primary barrier? (TWO ANSWERS)
- a) Stripper Rams
 - b) Stripper Rubber
 - c) Safety Rams
 - d) Shear/Seal BOPs
7. What is the main purpose of a Safety Head installed directly above Xmas tree?
- a) It will be a back up in case the Shear Blind Rams fail
 - b) It will be a back up in case the Xmas Tree Valves fail
 - c) It is to ensure pipe can be successfully cut and fall down, after which the Xmas Tree Valves can be closed.
8. What can cause or effect the depth of the balance point? (THREE ANSWERS)
- a) Well head pressure
 - b) Fluid contents of pipe
 - c) Speed of tripping pipe
 - d) Pipe weight in lbs/ft
 - e) Snubbing force used
 - f) Size of Stripper Rubber





9. What is a fluid pump in snubbing operations used for? (SIX ANSWERS)

- a) It is usually on standby for fire fighting control
- b) For equalizing the well pressure across the lower Stripping BOP
- c) To maintain closure pressure on the Stripping Rams
- d) To pump sand-wash fluids and remove sand out of the well during a sand-wash operation
- e) To close the Safety Rams
- f) To assist pressuring up the Stripper Rubber
- g) For circulating out hydrocarbons
- h) For pressure testing pressure control equipment
- i) To be able to fill up the work string
- j) To maintain closure pressure on the Stripper Rams
- k) To conduct pumping operations through a work string
- l) To be on standby for well kill operations

10. Which of the following are correct actions to take when pressure testing Stripper Rams and Safety Rams? (TWO ANSWERS)

- a) Pressure test Stripper Rams and Safety Rams from below
- b) Close the Annular Preventer or Stripper Rubber
- c) Test both Stripper Rams at the same time to ensure they can hold the same pressure
- d) Close Xmas Tree valves, then run at least 1 joint of pipe across the rams and secure; then pump through the kill line to perform the test

11. What are reasons to have fluid pumps on site when performing a snubbing operation? (TWO ANSWERS)

- a) A pump must be used for the BOP pressure tests
- b) A pump is required for any well kill operation
- c) A pump can be used to fill up the work string and start circulation
- d) A pump is required to equalize pressure between the stripping rams

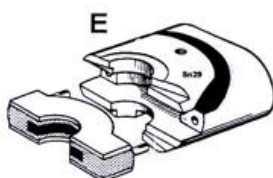
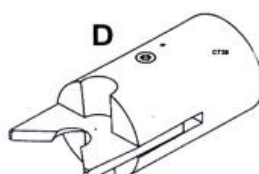
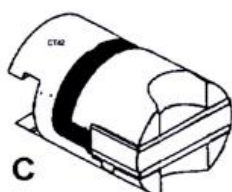
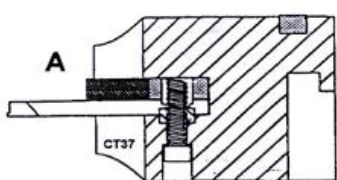
12. Which of the following are correct actions to take when pressure testing double BPVs [Check Valves in the BHA] after completing the rig up? (TWO ANSWERS)

- a) Hold the work string by Safety Rams such that the work string cannot move up or down
- b) Pump into the BOP Stack through the kill line and with the Swab Valve on the Xmas Tree closed
- c) Pressure test through the BHA at fast rate, then stop pump quickly
- d) Ensure that test certificates are available and state the correct test pressures as we are usually unable to pressure test BPVs on site





13. With reference to the drawing/sketches below, name the Ram Assemblies.



A: _____

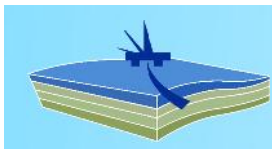
B: _____

C: _____

D: _____

E: _____





EXERCISE SNUBBING EQUIPMENT 4

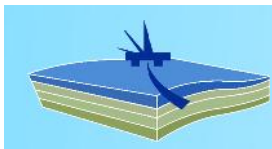
1. With the work string in the hole, we experience a leak past the Upper Stripper Rams. What would be the first action to take to enable us to repair this leak?
 - a) Kill the well without further delay
 - b) Close the Shear/Seal BOP
 - c) Close the Blind/Shear BOP
 - d) Close the Lower Stripper BOP first and then the Safety Rams [Pipe Rams]

2. A bleed off line on the snubbing BOP system has a built-in choke. What kind of choke do we normally use?
 - a) Fixed size orifice choke
 - b) Adjustable choke
 - c) Fully open choke to permit rapid depressuration whilst stripping
 - d) Type of choke depends on pressure regime

3. During a snubbing operation, the surface equipment rig-up is leaking from the connection at the spool between the Stripper Rams. Which secondary barrier must be closed to make the well safe and allow the leak to be repaired?
 - a) Annular BOP
 - b) Swab Valve
 - c) Upper Master Valve
 - d) DHSV
 - e) Safety Rams [Pipe Rams]

4. A snubbing unit is used to perform operations on a producing well. Suddenly, there is a small flow coming up and out of the work string. A Gray valve is then installed. Upon investigation, it is found that the leak is above the BHA. Which of the following actions will allow the work string to be pulled out safely? (TWO ANSWERS)
 - a) No action required. Continue pulling since there is a small leak
 - b) Kill the well
 - c) Drop and pump the Pump-Down Plug until it seats firmly in the Landing Nipple
 - d) Set a wireline-run Bridge Plug half a joint above the leak
 - e) Continue pulling out but use the Stripper Rams instead of Stripper Rubber





5. Is it a normal practice to change out a worn Annular Packing Element during a job?
 - a) Yes
 - b) No

6. Is it a normal practice to change out a worn Stripper Ram Inner Seal during a job?
 - a) Yes
 - b) No

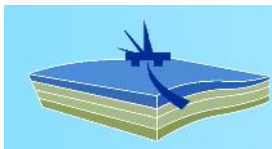
7. What is the purpose of the Blind/Shear rams?
 - a) To effectively seal on the tubular in the hole
 - b) To shear tubulars like the work string without sealing the hole
 - c) To shear tubulars like the work string while also seal or blind the hole

8. It is planned to use a snubbing unit to wash out sand in a well which has 3,500 psi Shut-In Tubing Head Pressure. What is the primary barrier of the snubbing unit when snubbing or stripping in the hole?
 - a) Stripper Rubber
 - b) Stripper Rams
 - c) Annular BOP
 - d) Safety Rams [Pipe Rams]

9. A snubbing unit has remotely hydraulically operated valves on the bleed-off line and equalizing loop. Also some valves on the kill line and choke lines are remotely operated. Where are these valves controlled or activated from?
 - a) BOP control unit
 - b) Control console on the work basket
 - c) Remote control room
 - d) BOP stack

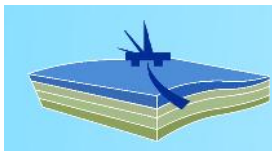
10. The snubbing unit has valves on bleed off line and equalizing loop line which are operated either remotely and manually. If we have one hydraulically and one manually operated valve in sequence, where should the manually operated valve be positioned?
 - a) Closest to the spool outlet [upstream of hydr. operated valve]
 - b) Either side of the remotely operated valve. It does not matter.
 - c) There is no need for manually operated valve since the control system is on the basket.
 - d) Furthest from the spool outlet [downstream of hydr. operated valve]





11. What are suitable actions that could be taken if we know there may be a leak somewhere in the snubbing work string?
(TWO ANSWERS)
- a) Drop and pump the pump-down plug in Landing Nipple [if leak below Landing Nipple]
 - b) Pull slowly and carefully out of hole
 - c) Set retrievable packer just above leak point
 - d) Cut and drop the work string at surface, then close Xmas tree valves.
12. What choke type is installed at the short equalizing loop on snubbing rig up?
- a) Fixed Bean or Positive Choke
 - b) Adjustable Choke
 - c) Gas Lift Choke
13. What choke type is installed at the choke manifold when we route hydrocarbons or other fluids from the well during any circulation?
- a) Fixed Bean or Positive Choke
 - b) Adjustable Choke
 - c) Gas Lift Choke
14. Why does the manufacturer of a Stripper Rubber always show the 3,000 psi maximum working pressure?
- a) It is just to confirm the working pressure, nothing special
 - b) If we use it at higher pressures, the rubber will experience accelerated wear
 - c) It is simply an API standard
15. Which of the following statements is correct regarding Shear/Blind Rams [SBR]?
- a) The SBR will only cut one size of work string
 - b) The SBR will not cut if there is a tension on the work string
 - c) The SBR will not cut if there is a torsion on the work string
 - d) The SBR will neither cut drill collars nor tool joints





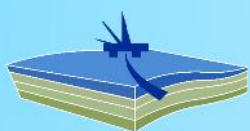
16. What are factors that have an effect on the wear of Stripper Rubbers? (FOUR ANSWERS)

- a) The work string conditions i.e. external pipe roughness
- b) The bottom hole pressure
- c) The well bore fluids when exposed
- d) The well head pressure
- e) The tripping speed
- f) The formation pressure

17. If the check valves are leaking a little, what should we do to bring the well back to a safe condition? (FOUR ANSWERS)

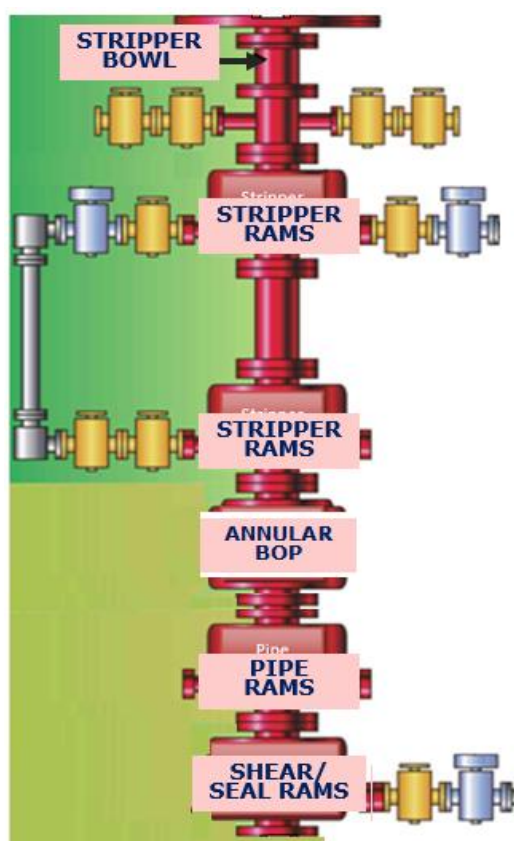
- a) Install a Stabbing Valve [FOSV]
- b) Leak test [inflow test] the Stabbing Valve [FOSV]
- c) Drop and pump the pump-down plug in Landing Nipple
- d) Pull out of hole and change the check valves
- e) It is OK if the leak is small. Continue operation
- f) Pump a heavy slug and pull out of hole
- g) Install a Gray Type of Valve [IBOP]





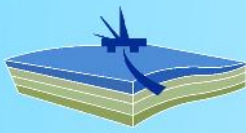
END-OF-COURSE PAPER SNUBBING EQUIPMENT 5

1. Heavy fluid is circulated from a well using a snubbing work string and therefore the well is now live. However, it is observed that the BPVs are leaking. What is the correct course of action?
 - a) Install the Full Opening Safety Valve [FOSV], close it, then rig up and run or pump down the Pump Down Plug [or Dart] to the Landing Nipple, inflow test it and continue with the work programme downhole
 - b) Install the Full Opening Safety Valve [FOSV], close it, then inflow test it and prepare to pull out of hole
 - c) Install the Full Opening Safety Valve [FOSV], close it, then rig up and run or pump down the Pump Down Plug [or Dart] to the Landing Nipple, inflow test it and prepare to pull out of hole
 - d) If the BPVs are not leaking much, then it is acceptable to continue with the work programme downhole
2. A run with a 2-3/8" work string was unsuccessful, because of a blockage in the tubing string. We are now planning to run a 1000 ft section of 1.9" work string below the 2-3/8" work string. What kind of changes must be made to the Snubbing BOP Stack that is shown below?

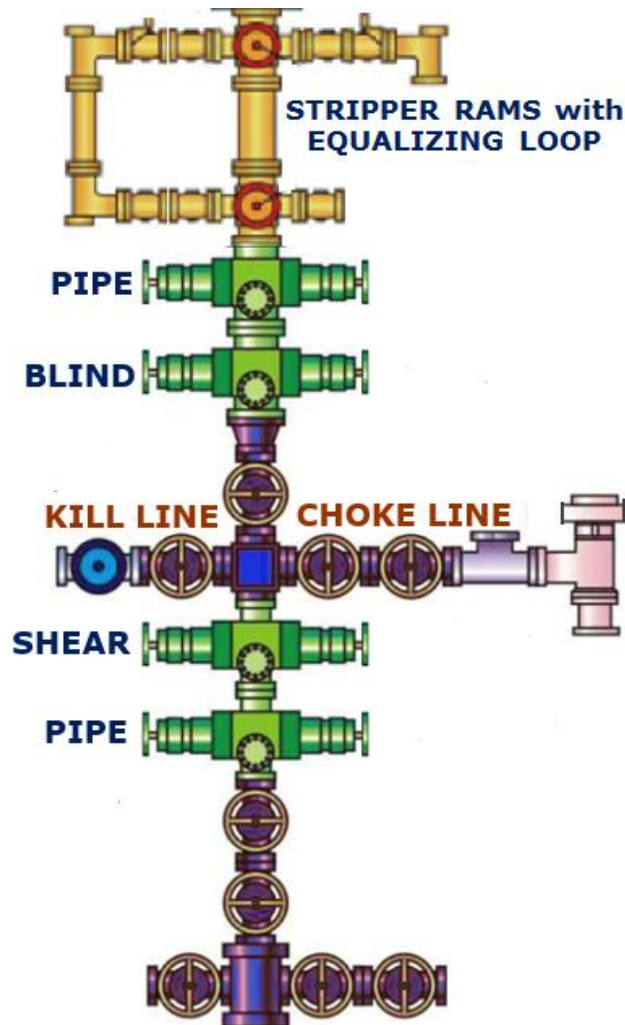


- a) Add BOP with 1.9" Pipe Rams [Safety Rams]
- b) Add a second pair of Stripping Rams
- c) Add BOP with Variable Rams
- d) No changes need to be made



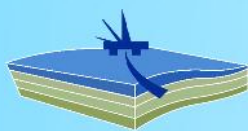


3. Given is a Snubbing BOP Stack. We experience a significant leak in the area of the Adaptor Flange, just above the Xmas Tree. The snubbing is done in 'heavy mode'. What immediate action should be taken?

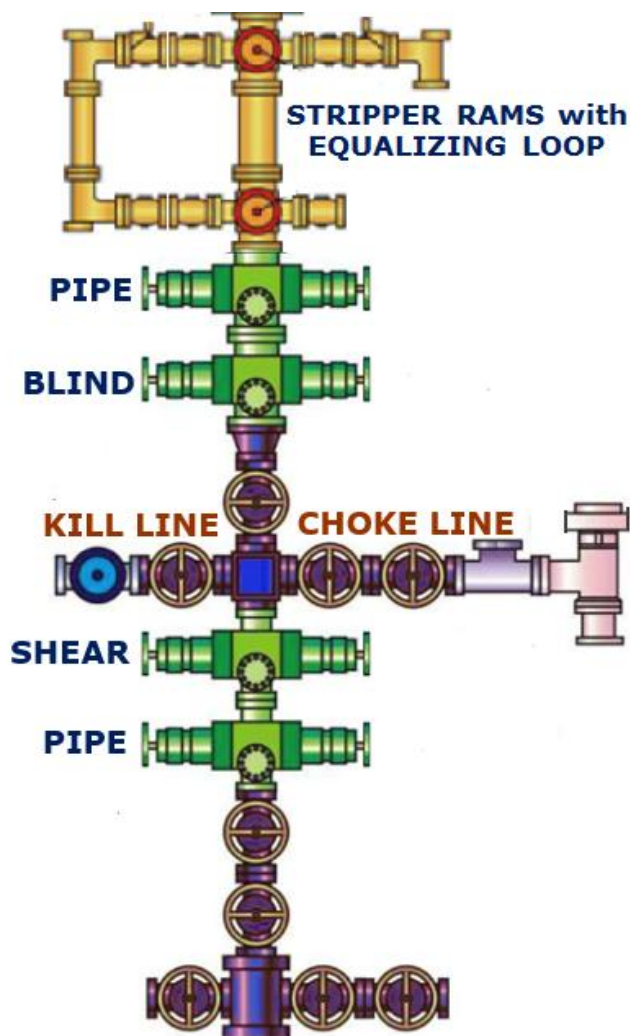


- a) Cut the string with the Shear Rams, then raise the string and close the Blind Rams
- b) Close the Lower Pipe Rams [Safety Rams]
- c) Stab the Full Opening Safety Valve and close it, set travelling snubbers and heavy slips, open stationary slips, cut the string with the Shear Rams, then raise the string and close the Blind Rams. Close the Swab Valve and Upper Master Gate Valve [counting turns]
- d) Drop the string. Close the Swab Valve and Upper Master Gate Valve [counting turns]
- e) Cut the string with the Shear Rams, then raise the string and close the Blind Rams. Close the Swab Valve and Upper Master Gate Valve [counting turns]



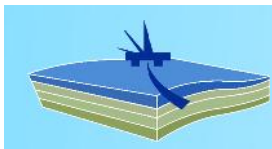


4. Given is a Snubbing BOP Stack. We experience a leak in the flange area of the mud cross carrying the kill and choke lines. The snubbing is done in 'heavy mode'. What immediate action should be taken?



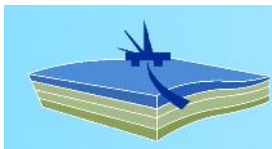
- Cut the string with the Shear Rams, then raise the string and close the Blind Rams
- Close the Lower Pipe Rams [Safety Rams]
- Stab the Full Opening Safety Valve and close it, set travelling snubbers and heavy slips, open stationary slips, cut the string with the Shear Rams, then raise the string and close the Blind Rams. Close the Swab Valve and Upper Master Gate Valve [counting turns]
- Drop the string. Close the Swab Valve and Upper Master Gate Valve [counting turns]
- Cut the string with the Shear Rams, then raise the string and close the Blind Rams. Close the Swab Valve and Upper Master Gate Valve [counting turns]





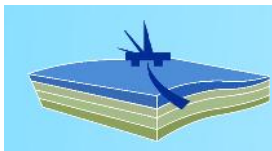
5. The statement is made that a Stripper Rubber has to be energized by pumping it up with a hand pump before it seals around the work string.
- a) True
 - b) False
6. Which of the following milling BHAs has the Circulation Sub in the correct position?
- a) Landing Nipple – Circulation Sub – Check Valve – Check Valve – Ball Operated Separation Sub – MudMotor – Mill or Bit
 - b) Landing Nipple – Check Valve – Circulation Sub – Check Valve – Ball Operated Separation Sub – MudMotor – Mill or Bit
 - c) Landing Nipple – Check Valve – Check Valve – Circulation Sub – Ball Operated Separation Sub – MudMotor – Mill or Bit
 - d) Landing Nipple – Check Valve – Check Valve – Ball Operated Separation Sub – Circulation Sub – MudMotor – Mill or Bit
7. Why is a one-gallon accumulator bottle connected to the Annular Preventer closing line?
- TWO ANSWERS
- a) It provides more time to close the Annular Preventer, which in turn makes it easier for the tool joints to pass
 - b) It reduces the time it takes to close the Annular Preventer when we really need such as when the well kicks or the well pressure is not constant
 - c) It maintains a more uniform closing control pressure and therefore a better seal when tool joints are stripped through it
 - d) It prevents over-pressuring of the closing line when tool joints are stripped through it
8. During a snubbing operation we observe a small flow from the work string, after which the Full Opening Safety Valve [FOSV] is stabbed on and closed. A wireline survey is run and identifies the leak point, which is 1000 ft above the BHA. The work string is at a depth of 8000 ft. What are the two actions necessary to make it safe to pull the work string from the well.
- TWO ANSWERS
- a) Drop the Pump Down Plug [Dart] and land/lock it firmly in the Landing Nipple just above the BHA
 - b) Continue to pull out and use the Stripper Rams instead of the Annular Preventer to control the well pressure
 - c) Kill the well without further delay
 - d) Make another wireline run and set a Retrievable Bridge Plug inside the work string, just above the identified leak point
 - e) Pull out of the well without further delay, pumping seawater, as there is no immediate risk if the flow from the string is small





9. Which of the following precautionary measures are important when stripping through an Annular Preventer?
TWO ANSWERS
- a) To monitor the weight indicator reading
 - b) To have a BHA dimension diagram readily available
 - c) To lubricate the work string
 - d) To retract the Stripper Rubber away from the work string
10. In order to mill a bridge plug, it is planned to snub a 2-3/8" work string into a well against an anticipated surface well pressure of 2350 psi. What would be the most likely BOP barrier configuration, from the Top to the Bottom of the BOP Stack?
- a) Annular Preventer – Upper Stripper Rams – Lower Stripper Rams – Stripper Rubber
 - b) Stripper Rubber – Annular Preventer – Upper Stripper Rams – Lower Stripper Ram – Pipe Rams – Shear/Blind Rams
 - c) Shear/Blind Rams – Stripper Rubber – Pipe Rams – Upper Stripper Rams – Lower Stripper Rams
 - d) Annular Preventer – Upper Stripper Rams – Lower Stripper Rams – Shear/Blind Rams
11. While stripping a work string into the well under pressure and 'pipe-heavy' conditions, which of the following statements is correct?
- a) If both stationary and travelling heavy slips are released, the string will be ejected from the well
 - b) If both stationary and travelling heavy slips are released, the string will drop into the well
12. What kind of gas is used to pre-charge the accumulator bottles of the BOP hydraulic control system?
- a) Oxygen
 - b) Air
 - c) CO₂
 - d) Nitrogen
13. To what pressure is a 5,000 psi BOP body tested by the manufacturer before it will be used in the field?
- a) 5,000 psi
 - b) 7,500 psi
 - c) 10,000 psi
 - d) 6,000 psi





14. After the Snubbing BOP Stack has been rigged up and function tested, we are now ready to start pressure testing of all the BOP equipment. Which of the following statements is correct regarding the tests on the BPVs, installed at the bottom of the work string?

TWO ANSWERS

- a) The BPVs can be tested by pressuring up the annulus via the kill line and with the Pipe Rams closed, then observe the work string for any leaks
- b) The BPVs are tested by pumping down the work string with the Annular Preventer closed
- c) The work string must be held in place by the travelling and/or stationary snubbers
- d) The BPVs can only be tested by performing an inflow test after the BHA has entered the well

15. What is the main reason for using Pipe Rams [Safety Rams] during a snubbing operation?

TWO ANSWERS

- a) To ensure a safe operation in the event of a flow from the well that cannot be controlled by BOP Stripping equipment
- b) To enable the repair of BOP Stack components that are above the Pipe Rams
- c) To have a back-up for the Stripping Rams and Stripper Bowl
- d) To clean and wipe the work string when it is being pulled out of the well

16. Is it possible to operate the Pipe Rams [Safety Rams] when the main power pack fails?

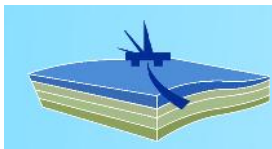
- a) Yes
- b) No

17. What are the reasons for installing an Annular Preventer between the Stripper Bowl and the Stripper Rams?

TWO ANSWERS

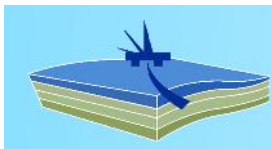
- a) To have a system that wipes and cleans the work string
- b) To have an additional secondary barrier that can seal around all sizes of the work string while changing the Stripper Rubber
- c) To have an additional primary barrier to the Stripper Rubber and Stripper Rams
- d) To have a tertiary barrier if the primary and secondary barrier fails





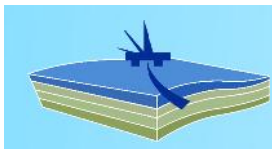
18. Which of the items listed below have the greatest effect on the depth of the balance point?
FOUR ANSWERS
- a) Pipe diameter
 - b) Unit weight of work string [lb/ft]
 - c) Snubbing force used
 - d) Wellhead pressure
 - e) Speed of running pipe
 - f) Fluid content in the work string [pipe full versus pipe empty]
19. Where is the Shear/Seal BOP [Safety Head] normally found when it is part of a Snubbing BOP Stack?
- a) Directly above the Pipe Rams [Safety Rams]
 - b) Directly below the Stripper Bowl
 - c) Directly below the Stripper Rams
 - d) Directly above the Xmas Tree or Wellhead
 - e) Anywhere, it does not matter where it is placed
20. When would we normally have to apply the largest snubbing force to the work string?
- a) When the first joint enters the well
 - b) When the tool joints pass through the Stripper Bowl
 - c) When the work string is at 'balance point' depth
21. What kind of slips are used in the initial [pipe light] phase when snubbing into the well under pressure?
- a) Travelling [heavy] slips and stationary [heavy] slips
 - b) Travelling snubbers and stationary [heavy] slips
 - c) Travelling snubbers and stationary snubbers
22. The statement is made that the Landing Nipple for the Pump Down Plug [Dart] is placed below the BPVs [[Check Valves]:
- a) True
 - b) False





23. The statement is made that the Stripper Bowl is normally placed at the bottom of the work window:
- a) True
 - b) False
24. During snubbing operations, is it normal practice to have to change out the Stripper Ram inserts or the Pipe Rams seals?
- a) It is normal practice to change out the Pipe Ram seals
 - b) It is normal practice to change out the Stripper Ram inserts
 - c) It is not normal practice to change out any Stripper Ram inserts or Pipe Ram seals
 - d) It is normal practice to change out both Stripper Ram inserts and Pipe Ram seals
25. Which of the following statements are true in relation to the Equalizing Loop on a Snubbing BOP Stack?
- a) It is connected from above the Upper Stripper Ram to below the Lower Stripper Ram
 - b) It is connected from below the Upper Stripper Ram to above the Lower Stripper Ram
 - c) It is connected from above the Upper Stripper Ram to above the Lower Stripper Ram
 - d) It is connected from below the Upper Stripper Ram to below the Lower Stripper Ram
26. During a 'pipe light' snubbing operation, we observe a small flow from the work string. What immediate action should be taken?
- a) Stab the Full Opening Safety Valve [FOSV] and close it
 - b) Bullhead kill fluid into the well using the Xmas Tree or Wellhead kill line inlet
 - c) Install a Circulating Head and pump kill fluid down the drill string
 - d) Drop the Pump Down Plug [Dart] and pump/lock into the Landing Nipple
27. Why is a Bleed Off Line always used as part of the pressure equalizing process?
- a) To control the well when killing it with returns coming from the annulus
 - b) To enable the pump to equalize pressure below the Upper Stripper Ram
 - c) To route the influx to the flare boom or pits in case the Pipe Rams fail and the Stripper Rams perform as a back-up secondary barrier
 - d) To enable to bleed off pressure between the Stripper Rams during the snubbing operations and with the well under pressure





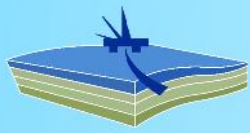
28. A work string is being snubbed into the well when a leak is observed across the Upper Stripper Rams. What is the first action to take prior any repair performed on these Upper Stripper Rams?
- a) Stop any pipe movement, then close the Lower Stripper Rams and then the Pipe Rams [Safety Rams]
 - b) Kill the well without any delay
 - c) Close the Shear/Seal Rams [Safety Head]
 - d) If the leak is small, it is okay to continue snubbing in or out of the well using the Pipe Ram to Pipe Ram or Pipe Ram to Annular stripping method

29. Pressure control devices are 'normally' used as a Primary, as a Secondary or as a Tertiary Barrier. Mark your choice with an 'X' in the table below!

		PRIMARY	SECONDARY	TERTIARY
[A]	Shear/Seal Rams			
[B]	Pipe Rams			
[C]	Stripper Rams			
[D]	Stripper Bowl			

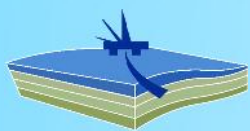
30. Which of the following statements is correct regarding snubbing on live wells and the placement of the Teleseopic and Stationary Guide Tubes in both the Work Window and across the Jack Assembly
- a) It guides the work string into the well
 - b) It makes the rig-up much stiffer and safer
 - c) It prevents severe buckling of the work string
 - d) It allows personnel to work safely around the work string
31. If the Hydraulic Power Pack fails, what should we do?
- a) If possible, position work string at a suitable height, set all slips, and then install the stab-in safety valve
 - b) If possible, position work string at a suitable height, close the pipe rams, set all slips, and then install stab-in safety valve
 - c) If possible, position work string at a suitable height, install stab-in safety valve, set all slips, and then close pipe
 - d) If possible, position work string at a suitable height, set all slips, install stab-in safety valve, and then close pipe rams





32. For a planned well intervention operation a potential H₂S gas risk is identified. When the H₂S gas alarm goes off, what would be the safest action?
- a) Put on H₂S gas mask and breathing apparatus, install and close stab-in safety valve and close safety rams
 - b) Put on H₂S gas mask and breathing apparatus, and find out the source of the H₂S leak
 - c) Put on H₂S gas mask and breathing apparatus and wait for the next shift to be fully prepared
 - d) Put on H₂S gas mask and wait for further instruction
33. During snubbing operations, both BPVs are leaking and you observe back flow from the work string. What is the next safest action to take?
- a) Stop operations and pull out immediately to change out the leaking BPVs
 - b) Install stab-in safety valve, close safety valve, insert pump down plug, equalize pressure between wellbore and kill line, open safety valve, pump down the plug to the landing nipple
 - c) Insert pump down plug, install stab-in safety valve, close safety valve, equalize pressure between wellbore and kill line, open safety valve, pump down the plug to the landing nipple
 - d) Insert pump down plug and pump down the plug to the landing nipple





WORKBOOK SNUBBING EQUIPMENT – ANSWER KEYS

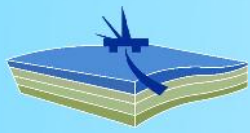
EXERCISE SNUBBING EQUIPMENT-1

1.	b
2.	a
3.	a
4.	d
5.	a
6.	c
7.	a, c
8.	d
9.	b
10.	b
11.	b
12.	c

EXERCISE SNUBBING EQUIPMENT-2

1.	a
2.	c
3.	b
4.	b
5.	b
6.	d
7.	a
8.	a. The Safety Ram or Pipe Ram is already a Secondary Barrier. The Inner Seal must be changed out prior starting any job. Moreover, it cannot be changed if there is pipe in hole, as there are no barriers left to permit a safe change out
9.	a
10.	c, d
11.	a
12.	b
13.	a
14.	b
15.	a
16.	b
17.	a
18.	a
19.	b
20.	b
21.	b
22.	d





EXERCISE SNUBBING EQUIPMENT-3

1.	a, c, d, f
2.	a
3.	d, e
4.	a
5.	c
6.	a, b
7.	c
8.	a, b, d
9.	d, g, h, i, k, l
10.	a, d
11.	b, c
12.	a, b
13.	A: Shear/Blind Ram
	B: Pipe Ram
	C: Blind Ram
	D: Shear Ram
	E: Stripper Ram

EXERCISE SNUBBING EQUIPMENT-4

1.	d
2.	a
3.	e
4.	b, d
5.	b
6.	a
7.	c
8.	b
9.	b
10.	a
11.	a, c
12.	a
13.	b
14.	b
15.	d
16.	a, c, d, e
17.	a, b, c, d





PTS

IWCF Well Intervention
Well Control WORKBOOK

LEVEL 3/4

---- END ----

