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 suffing 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

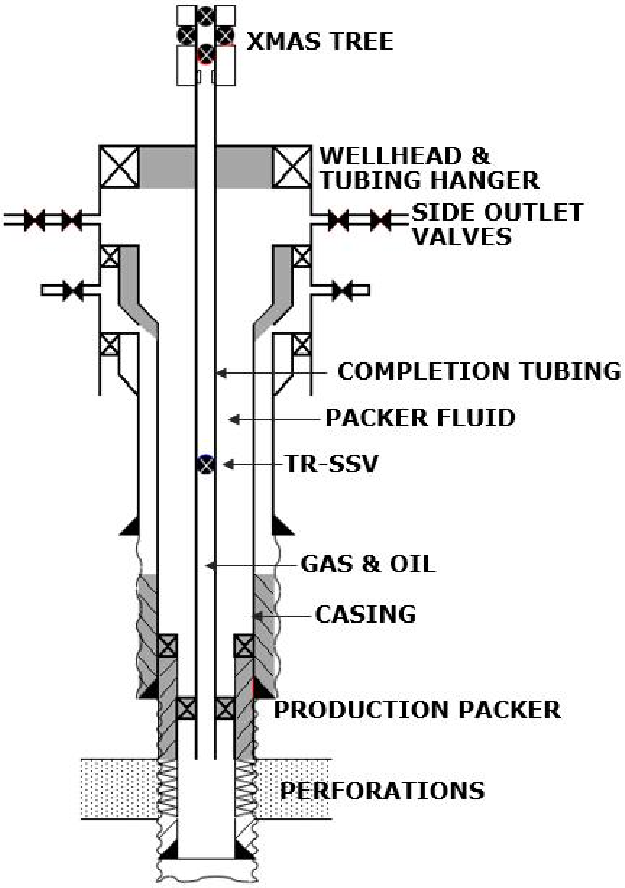
Answer: ______________________

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 <u>before</u> and <u>after</u> 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 incaple 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 maintaince 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 <u>prevent</u> 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 <u>remove</u> 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?

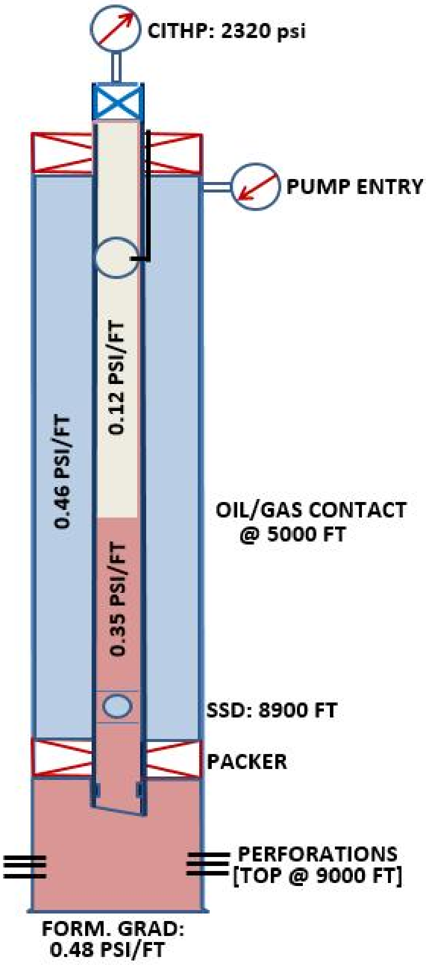
Answer: __________ bbls

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



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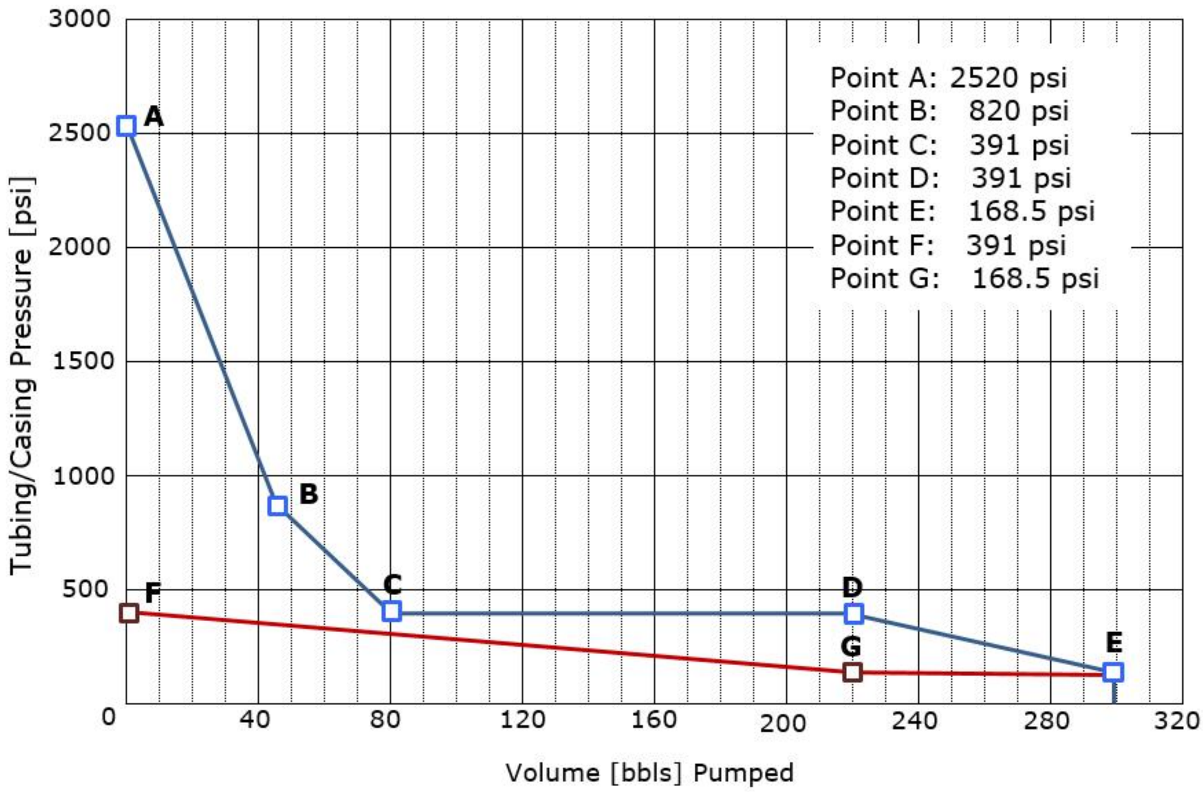

52. You are planning to set a tubing plug in a nipple profile. What should be considered when you perform this job?
THREE ANSWERS

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-Controled 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