Drilling Combined Surface & Subsea – Day 1

1. Why should you leave spare capacity in the active pits when circulating out a kick?

A. To store the kick fluid as it is circulated from the wellbore
B If the kick is gas it will expand and the active pit level will increase
C. You might lose returns while circulating the kick from the wellbore
D. If the kick is oil it will expand and the active pit level will increase

2. Which of the following drilling conditions can make it more difficult for the driller to detect a kick?

A. High permeability formations with oil based mud
B. Low permeability formations with oil based mud
C. High permeability formations with water based mud
D. Low permeability formations with water based mud

3. Why is it very important for rig personnel to detect a kick as early as possible?

A. To prevent gas expansion as it is circulated up the wellbore
B. To reduce risk of formation breakdown during the kill operation
C. To prevent gas migration
D. To prevent oil expansion as it is circulated up the wellbore

4. What is the definition of a 'negative' pressure test?

A. A test performed on a barrier where pressure on top of a barrier is increased to a value higher than the pressure below the barrier
B. A test performed on a barrier where pressure on top of a barrier is reduced to a value lower than the pressure below the barrier
C. A test performed on a barrier where pressure on top of a barrier is equal to the pressure below the barrier
D. A test performed on a barrier where gas is injected downhole to test the integrity of the barrier

5. Which of the following is the most common cause of abnormally high formation pressures worldwide?

A. Carbonate layers of formation
B. Artesian flow
C. Trapped fluid in shale formations
D. Faults

6. What is the new pump pressure at 40 strokes per minute (SPM) if the pump pressure was 450 psi while circulating at 32 SPM?

A. 557 psi
B. 585 psi
C. 610 psi
D. 703 psi

7. The well is flowing at a connection and you suspect the well is "ballooning", which of the following is the safest and most conservative action taken by the driller?

A. Continue drilling ahead
B. Record the time it takes for 5 bbls of mud to flow into the trip tank, then shut in well
C. Check and verify that the cuttings returned over the shakers is shale
D. Shut the well in, call the supervisor and record pressures and pit gain

8. Calculate the hydrostatic pressure of an 11.4 ppg fluid at 7700 ft MD (6550 ft TVD)?

A. 3600 psi
B. 3882 psi
C. 4020 psi
D. 4565 psi

9. Severe losses are observed while drilling ahead. The pumps were shut down and the mud in the well could not be seen. The well was then filled to the top with water and remained static.

Mud density	**13 ppg**
Brine water density	**8.6 ppg**
Height of water column in the annulus	**180 ft**

What is the decrease in bottom hole pressure with the 180 ft of water compared to the pressure before the losses occurred?

A. 41 psi
B. 46 psi
C. 67 psi
D. 78 psi

10. The well is losing mud at 15 bbls per hour while drilling ahead. At the connection the well is flowing. When the pumps are restarted you begin to lose mud again. Which of the following could be happening downhole?

A. The mud is u-tubing due to different weights in the drill string and annulus
B. The well is losing mud to the formation, causing a reduction in hydrostatic pressure
C. The well is indicating that the formation may be "ballooning"
D. An influx in the wellbore is "ballooning"

11. You are currently drilling a high temperature well. The downhole mud temperature is significantly higher compared to the surface mud temperature. What effect will the high temperature have on downhole hydrostatic pressure?

A. It will increase the effective mud density downhole and cause a higher hydrostatic pressure
B. It will decrease the effective mud density downhole and cause a lower hydrostatic pressure
C. None, the mud in the well is a constant density
D. Temperature will not affect mud density

12. During a flow check you cannot determine if the well is flowing. What action could be taken to help measure a small amount of flow from the well?

A. Shut in the well and line up through the mud-gas separator and monitor for flow at the shakers
B. Shut in the well and line up through the mud-gas separator and monitor for flow at the mud gas separator
C. Line up on the trip tank and monitor for a gain in the pit level
D. Line up on the active pit and monitor for gain in the pit level

13. The well is successfully shut in. What is the casing pressure in this static u-tube?

Well Information:
Drill Pipe pressure reads 0 psi (no float in the string)
Well Depth = 6000 TVD/ 6725 MD
Drill String full of 9.8 ppg mud
Annulus full of 6.2 ppg gas/mud mixture

A. 1123 psi
B. 1259 psi
C. 1934 psi
D. 3057 psi

14. What action is considered a "procedural barrier"?

A. Setting a packer assembly
B. Actively monitoring the well for gains or losses
C. Writing handover notes for your relief
D. Decreasing the rate of penetration

15. Increasing flowback time has been recorded over the last five connections. The driller believed that the flowback time was too long and closed the well in. There is 170 psi on both the drill pipe and the annulus. The driller has bled off 50 psi. SIDPP returned to 170 psi and SICP is now 200 psi. The bleed off procedure was repeated and SIDPP returned to 170 psi and SICP is now 220 psi.

What is the best explanation of the current situation?

A. This well is ballooning. Bleed off and drill ahead
B. This is the result of gas migration. Begin the volumetric procedure
C. This is a kick. Prepare to carry out the chosen kill operation
D. This is a kick. Circulate at the maximum pump rate to remove the influx

16. The driller is pulling out of the hole with 5 inch drill pipe and monitoring the well on the trip tank. During the last 5 stands the trip tank has increased by 3 barrels. What action should the drill take?

A. Continue pulling pipe. 3 barrels is the correct displacement for 5 inch drill pipe
B. Perform a flow check. This could be a kick that has been swabbed in
C. Decrease pipe pulling speed, monitor the well on the active mud pits
D. Increase pipe pulling speed to minimize the potential for swabbing

17. Which of the following is the best definition of Porosity?

A. The amount of void or empty space in the rock, expressed as a percent
B. The ability of formation fluids to move through the formation
C. The amount of overburden pressure applied to the formation
D. The total pressure applied to the formation

18. If a shallow-gas flow is encountered while drilling the surface hole, which of the following actions should be performed at the same time as activating the diverter?

A. Direct flow through the mud-gas separator
B. Maintain constant pump rate
C. Increase pump rate
D. Decrease pump rate

19. The current drilling program requires a formation integrity test (FIT) to 15.3 ppg equivalent mud weight (EMW) at the casing shoe.

Casing Shoe Depth = 4500 feet (TVD); 5700 feet (MD).
Current Mud Weight = 9.8 ppg.

What surface pressure is required to test the casing shoe to the 15.3 ppg EMW?

A. 1144 psi
B. 1287 psi
C. 1630 psi
D. 3580 psi

20. Which of the following is the best definition of Maximum Allowable Annular Surface Pressure (MAASP)?

A. Total pressure applied at the shoe that will cause fluid losses
B. Total pressure that will cause fluid losses at the casing shoe minus the mud hydrostatic at the casing shoe
C. The difference in pressure between the annulus hydrostatic pressure and formation pressure
D. Minimum pump pressure required to start a well kill operation

Answer Key – Day 1

1.	B	8.	B	15.	C
2.	B	9.	A	16.	B
3.	B	10.	C	17.	A
4.	B	11.	B	18.	C
5.	C	12.	C	19.	B
6.	D	13.	A	20.	B
7.	D	14.	B		

Formulas & Problems Requiring Calculations

6. Intertek Formula #14

Pump Pressure/Pump Stroke Relationship psi = Present Pressure, psi x (New SPM ÷ Old SPM)^2

$$450 \times \left(\frac{40}{32}\right)^2 = 703 \text{ psi}$$

8. Intertek Formula #3

Hydrostatic Pressure, psi = Mud Weight, ppg x 0.052 x True Vertical Depth, ft

$$11.4 \times 0.052 \times 6550 = 3882 \text{ psi}$$

9. Reduction in BHP psi = (Old MW ppg – New MW ppg) x 0.052 x True Vertical Depth, ft

$$(13.0 - 8.6) \times 0.052 \times 180 = 41 \text{ psi}$$

13. SICP psi = (MW ppg in Drillstring – MW ppg in Annulus) x 0.052 x True Vertical Depth, ft

$$(9.8 - 6.2) \times 0.052 \times 6000 = 1123 \text{ psi}$$

19. Surface LOT psi = (MAMW ppg – Current MW ppg) x 0.052 x True Vertical Depth, ft

$$(15.3 - 9.8) \times 0.052 \times 4500 = 1287 \text{ psi}$$