EXAM PART B – PERMANENT PLUG & ABANDONMENT

Maximum score is 100 points

1. Briefly define "*Well Integrity*". (**5p**)

2. In old wells, "*Tubing erosion*" and "*tubing corrosion*" are common integrity issues. Elaborate the difference between the terms "*corrosion*" and "*erosion*". (**5p**)

3. When downhole activities or production from a well is discontinued, the well status needs to be distinguished. Generally, three different statuses are distinguished. List them and briefly define them. (**5p**)

4. List the three abandonment phases, in Permanent P&A, and describe them in your own words. (**5p**)

5. List two primary functions of an environmental plug. (**5p**)

6. Light Well Intervention Vessels (LWIV) have been proved to be a cost-efficient intervention approach for subsea wells. List four operations that could be performed by deploying a LWIV during a permanent P&A operation. (**5p**)

7. Besides CBL-VDL logs, there are two different techniques which could be used to determine cement isolation behind the casing. These two techniques have been listed as follows. Explain the concept of each technique in your own words.

    a. Listening to flow behind casing. (**3p**)

    b. Measuring temperature effect of flow. (**3p**)

8. Using coiled tubing has been suggested for performing rigless permanent P&A. List three reasons that coiled tubing may be limited as a solution for rigless permanent P&A. (**6p**)

9. List three cement-plug placement techniques. (**3p**)

10. Portland cement is the prime material used for zonal isolation and permanent P&A. List four drawback of Portland cement properties in regards to characteristics of suitable plugging material. (**6p**)

11. A subsea well, which is located in an ultra deep-water area, is going to be permanently plugged and abandoned. The well suffers from sustained casing pressure in A- and B- annulus. Logging data shows a shallow gas zone, which has not been isolated properly. By using the given information and Appendices A1-A3, write the P&A code for the well. (**5p**)

12. Write three reasons for not being able to perform P&A activities entirely rigless. (**6p**)

13. Perforate, Wash, Cement (PWC) has been suggested as a technique to establish annular barrier where there is no casing cement. However, there are some challenges associated with this technique. List two challenges associated with PWC. (**6p**)

14. Consider a 5-in. drillpipe is performing section milling of a 9 5/8-in. casing at 8000 ft with a mud weight of 10.8 ppg whereas the annular pressure loss is 460 psi. Assume that the pore pressure and fracture pressure at 8000 ft are 10.2 ppg and 11.7 ppg, respectively. The wellbore is vertical.

    a. Does the downhole pressure fracture the formation? (**5p**)

    b. Consider the same situation where the casing is 12 ¼-in. and the annular pressure loss is 340 psi. Does the downhole pressure fracture the formation in this scenario? (**5p**)

15. Consider a situation where a 500 ft balanced cement-plug is going to be installed entirely in an openhole by utilization of a workstring of 4 ½-in. size. The wellbore is vertical with 8,000 ft of depth. The openhole size is 8 ¾-in. and the production casing size is 9 5/8-in. The plan is to pump 24 bbl of a wash fluid with density of 10 lbm/galUS ahead of G cement slurry with density of 15.8 lbm/galUS. The same wash fluid is going to be pumped behind the cement slurry (see **Figure 1**). Note that the wellbore fluid has a density of 9.2 lbm/galUS. Assume no washout in openhole and production casing shoe at 5000 ft. Consider a string capacity factor of 0.01422 bbl/ft and annular capacity of 0.0547 bbl/ft. [1 ft : 12-in., 1 galUS : 231 in^3].

    a. Calculate the required volume of cement slurry for the balanced cement-plug. (**3p**)

    b. Calculate the height of cement-plug when workstring is inside the plug. (**3p**)

    c. Calculate the required volume of wash fluid to be pumped behind the slurry without compromising the balanced-plug. (**7p**)

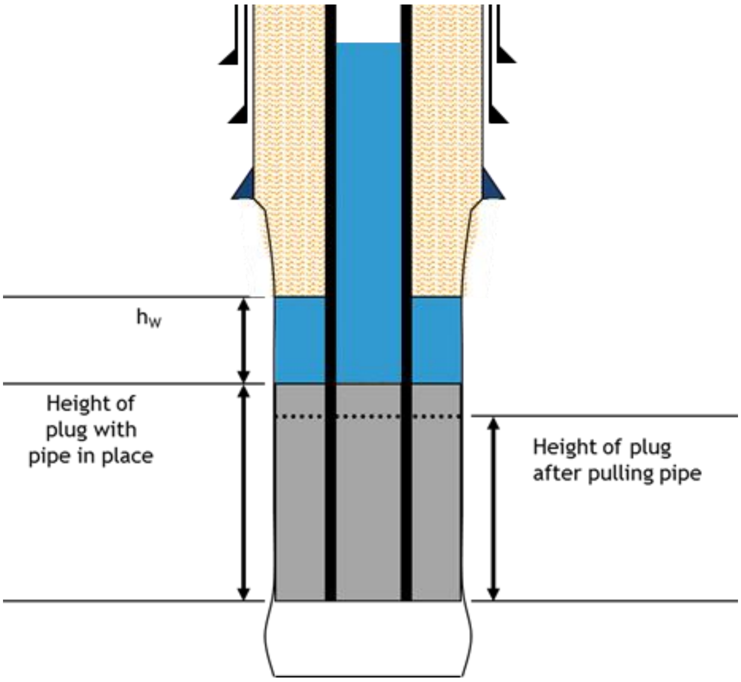

Figure 1 – Wellbore schematic.

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16. All the following options are the functional requirements of permanent barriers, EXCEPT: (**1p**)

    a. Sealing
    b. Non-Setting
    c. Placeability
    d. Durability

17. Which option is NOT the root causes leak around the bulk plugging material? (**1p**)

    a. Chemical degradation.
    b. External/internal stresses exceeding strength limit.
    c. Poor quality of placement.
    d. Perforated, cemented and washed plug.

18. Find the CORRECT option in regard to verification of a permanent barrier: (**1p**)

    a. In regard to permanent P&A, cement plug installed entirely in open hole should be pressure tested.
    b. In regard to permanent P&A, cement plug installed entirely in cased hole should only be weight tested.
    c. In regard to permanent P&A, cement plug installed entirely in open hole should be weight tested.
    d. In regard to permanent P&A, cement plug installed entirely in open hole should be pressure tested and weight tested.

19. When permanent barrier is placed. It is tagged to: (**1p**)

   a. Test its bonding to formation.
   b. Verify the depth of plug.
   c. Pressure test the plug.
   d. Eliminate Formation Integrity Test (FIT).

20. Installation of large BOP during P&A introduces some challenges. Select the CORRECT alternative: (**1p**)

   a. A larger BOP means limited space and handling capacity in offshore wells
   b. A larger BOP means more fatigue stresses on the wellhead
   c. Function testing of BOP is more time consuming
   d. All above-mentioned alternatives

21. All the alternatives are correct, EXCEPT: (**1p**)

   a. A fundamental requirement for an effective seal is that the entry pressure of the seal to be greater than the buoyancy of the fluids in bearing formation beneath.
   b. The seal entry pressure, seal capacity, is the capillary pressure at which fluid pressure overpasses the capillary entry threshold and therefore, fluid leaks into the pore space of barrier.
   c. The capillary entry pressure is a function of pore radius.
   d. The capillary entry pressure is independent of fluid type.

22. Which option does NOT have influence on the Cement Bond Log (CBL) when evaluating casing cement quality: (**1p**)

   a. Downhole pressure and temperature
   b. Wellbore-fluid properties
   c. Casing size and thickness
   d. Longer transit time

23. Select the correct option in regards to CBL-VDL logs: (**1p**)

   a. Fast formations increase the transit-time.
   b. When the cement thickness is too small, energy reflections at the cement/formation interface can interfere with the casing signal.
   c. As the casing size increases, so does the path through the wellbore fluid. This leads to some signal attenuation and increased free-pipe amplitudes.
   d. None of the above-mentioned options.

24. Select the correct option accordance with NORSOK D010 (rev. 4): (**1p**)

   a. An open hole cement plug extended into the casing shall be pressure tested.
   b. Placing one continuous cement plug in a cased hole is an acceptable solution as part of the primary and secondary well barriers when placed on a viscous pill.
   c. CBL-VDL is an acceptable barrier verification method for a plug placed entirely in an open hole.
   d. None of the above-mentioned options.

Table 3.1: Criteria for Classifying PHASE 1 Well Abandonment Complexity

x:Not Feasible ✔:Required O:Optional

Note #	Well Characteristics / Condition at abandonment	Well Abandonment Complexity: Type 1 Simple Rig-less	Type 2 Complex Rig-less	Type 3 Simple Rig	Type 4 Complex Rig
1	Sustained Casing Pressure due to hydrocarbons or overpressures	X	X	X	✔
2	Not cemented casing or liner at barrier depths (cap rock)	X	X	X	✔
3	Restricted access to tubing	X	X	✔	O
4	Deep electrical or hydraulic lines present at barrier depth	X	X	✔	O
5	Annular Safety Valve (ASV) present	X	X	✔	O
6	Packer set above cap rock	X	X	✔	O
7	Site does not allow for CT/HWU pumping operations	X	X	✔	O
8	Multiple reservoirs to be isolated	X	✔	O	O
9	Tubing has leak (e.g. corrosion, accessories)	X	✔	O	O
10	Inclination > 60 deg above packer (wireline access)	X	✔	O	O
11	Well with good integrity, no limitations	✔	O	O	O

Notes:

1. Sustained Casing Pressure –SCP related to overpressures or hydrocarbons originating from the reservoir(s) indicates that the primary casing cementation has failed and requires repair at the reservoir caprock level.
2. Not cemented casing or liner at the depth of the barrier (cap rock). Also applies to a (not cemented) scab-liner. The casing will have to be milled or removed to place a competent barrier. Note: The length between top of potential inflow (e.g. bottom of caprock formation) and top of barrier must be more than 200 ft to place permanent barrier (assumed that good cement is achievable).
3. Restricted Tubing Access – tubing may contain a fish, stuck plugs, perhaps be collapsed or parted, hence obstructing or limited access to the depth of the deepest permanent barrier, typically the production packer. Access may be restricted due to internal deposits (scale, wax) if not removable or able to provide a seal in conjunction with cement. The tubing will have to be recovered by a rig.
4. Deep gauge or electrical cables, or hydraulic lines – a data or power cable or hydraulic line is not acceptable to cross a permanent barrier and has to be removed. The tubing is to be recovered possibly requiring a rig.
5. Annulus Safety Valve (ASV) – An Annulus Safety Valve may not allow adequate flow for a through-tubing circulation and cementation, thus will require the tubing to be removed, possibly requiring a rig.
6. Packer set above cap rock – if the deepest barrier is to be placed below the production packer, this will have to be milled unless coiled tubing access is possible.
7. Poor access of CT/HWU to site – offshore platform may not be capable of accommodating equipment, crew or crane and a support vessel is required.
8. Multiple reservoirs to be isolated. This can often be achieved will coiled tubing. If not a rig is required to remove the completion and packers as a TYPE 4 operation.
9. Leaking tubing – if the tubing is leaking, it cannot be used as a conduit for pumping cement. This will have to be recovered unless coiled tubing access is possible.
10. High inclination (no wireline access) – due to inclination above 60 deg, wireline access may not be possible for setting wireline plugs and punching casing.
11. Well with good integrity – no limitations for through-tubing rig-less abandonment.

Table 3.2: Criteria for Classifying PHASE 2 Well Abandonment Complexity

x:Not Feasible ✔:Required O:Optional		Well Abandonment Complexity			
Note #	**Well Characteristics / Condition at abandonment**	**Type 1** Simple Rig-less	**Type 2** Complex Rig-less	**Type 3** Simple Rig	**Type 4** Complex Rig
1	Sustained Casing Pressure due to hydrocarbons or overpressures	X	X	X	✔
2	Restricted access to casing	X	X	X	✔
3	Not isolated fresh water aquifers / zones	X	X	X	✔
4	Not cemented casing or liner at barrier depths (cap rock)	X	X	X	✔
5	Not isolated Shallow gas	X	X	X	✔
6	Site does not allow for CT/HWU pumping operations	X	X	✔	O
7	Poor primary casing cementation	X	X	✔	O
8	No tubing in well	X	✔	O	O
9	Inclination > 60 deg above barrier depth (wireline access)	X	✔	O	O
10	Well with good integrity, no limitations, tubing in place	✔	O	O	O

Notes:

1. Sustained Casing Pressure – SCP on any of the casing annuli related to overpressures or hydrocarbon zones shallower than the reservoir, indicates that primary casing cementations have failed and require repair for final abandonment.
2. Casing access restricted – casing may have collapsed or parted, obstructing access to the production packer, where the deepest barrier is anticipated.
3. Fresh water zones – Fresh water zones will require protection if poorly isolated.
4. Not cemented casing or liner at the depth of the barrier (cap rock). Also applies to a (not cemented) scab-liner. The casing will have to be milled or removed to place a competent barrier. Note: The length between top of potential inflow (bottom of caprock formation) and top of barrier must be more than 200 ft to place permanent barrier (assumed that good cement is achievable).
5. Shallow gas not isolated – Un-cemented (low saturation) gas zone will cause leaks to surface when casing is cut and removed. This can be related to Sustained Casing Pressure. Such zones require isolation after the tubing has been removed by a rig. Requires casing removal or milling.
6. Poor access of CT/HWU to site – offshore platform may not be capable of accommodating equipment, crew or crane and a support vessel is required.
7. If primary casing is poorly cemented, then a rig may need to remove long sections of casing.
8. No tubing in well – if the tubing has been removed under Phase 1, a work string is required to place a permanent barrier. This can be provided by CT, HWU, or rig.
9. High inclination (no wireline access) – due to inclination above 60 deg, wireline access may not be possible for setting wireline plugs and punching casing.
10. Well with good integrity – no limitations for through-tubing rig-less abandonment. Only a surface barrier is required that can be placed through the tubing.

Table 3.3: Criteria for Classifying PHASE 3 Well Abandonment Complexity

x:Not Feasible ✔:Required O:Optional

Note #	Well Characteristics / Condition at abandonment	Well Abandonment Complexity: Type 1 Simple Rig-less	Type 2 Complex Rig-less	Type 3 Simple Rig	Type 4 Complex Rig
1	Poor integrity of conductor	X	X	X	✔
2	Platform unable to suspend conductor load during raising	X	X	✔	O
3	Water depth beyond limitation for cutting by LWIV (Subsea well)	X	X	✔	O
4	Conductor cutting/retrieval rig-less	✔	O	O	O

Notes:

1. Poor integrity of conductor – An involved programme will be required in case a conductor has poor integrity (corrosion, weak connectors) or a shallow restriction or damage.
2. Platform unable to suspend conductor load during retrieval – The platform may not be strong enough to suspend the heavy conductor load, which may include cemented inner casing.
3. Water depth beyond limitation for cutting conductor by LWIV – The cutting equipment typically used by a Light Well Intervention Vessel (LWIV) may have water depth limitations, beyond which a rig is required.
4. Conductor: Site can accommodate rig-less cutting and retrieval spread or retrieval planned with heavy lift vessel. Site can support loads of raising a multi-string conductor from the seabed, accommodate jacking spread, crane and crew. Annuli are free of polluting fluids. No need to install environmental plug.

   The Operator will need to decide from a budget-holding standpoint whether to include or exclude conductor retrieval in Phase 3, in the event that the conductors are to be retrieved by Heavy Lift Vessel.