10 Wireline operations

10.1 General
This section covers requirements and guidelines for well integrity wireline (WL) operations. A wireline operation is a technique for deployment of various electrical or mechanical downhole tools (logging tools, plugs, packers, perforating guns, shifting tools, pulling tools etc.) on electrical cables, braided cables or slickline. The operations are performed in pressurised wells or in dead wells.

The purpose of this section is to describe the establishment of well barriers by use of well barrier elements and additional requirements and guidelines to execute this activity in a safe manner.

10.2 Well barrier schematics
Well barrier schematics (WBS) shall be prepared for each well activity and operation.

Samples of well barrier schematics for selected situations are presented at the end of this section (10.7).

10.3 Well barrier acceptance criteria
The following list defines specific requirements and guidelines for well barriers:

10.3.1 Well control equipment configuration
The following basic well control equipment configurations should be used. Note: Additional elements (eg. additional BOP ram functions) should be considered based on each operation specific risk analysis.

a) For operations in a surface completed well
   1. Pressure control head – including a device that will automatically seal of the wellbore in the event the wireline breaks and is ejected from the wellbore
      1. For slickline – a stuffing box.
      2. For braided or electric cable – a stuffing box and sufficient number of flow tubes (grease head) to contain the applicable well pressure taking into account cable size and gas content in the well.
   2. Lubricator
   3. Wireline BOP
      3. For slickline – a slickline ram maintaining pressure from below
      4. For braided or electric cable – dual rams maintaining pressure from above and below creating a grease chamber between them
   4. WL safety head (shear/seal ram with independent hydraulic operation).
b) For operations with a riserless lubricator system on a subsea completed well

1. Pressure control head
2. Tool catcher (or tool trap)
3. Cutting/sealing ram or valve
4. Lubricator
5. Upper and lower isolation valves
6. Safety head (shear/seal ram)

10.3.2 Deployment of toolstrings

Deployment of long wireline toolstrings (in excess of the available surface lubrication length) may be achieved as follows:

a) Use of deployment bar and deployment rams (see WBS examples for one possible configuration)
   1. A double block principle (e.g., by use of two separate rams) shall be applied for sealing around the deployment bar.

b) Use of a downhole lubricator valve (ball type) above (and in addition to) the downhole safety valve
   1. The production tubing above the downhole safety valve shall be displaced to an inert fluid
   2. The downhole safety valve shall be closed and tested in the direction of flow potential
   3. The lubricator valve shall be closed and tested from above to the shut-in wellhead pressure + 70 bar.

c) Use of the downhole safety valve with a drop protection function for the downhole safety valve
   1. The production tubing above the downhole safety valve shall be displaced to an inert fluid
   2. Crosshead circulation via a trip tank will be in place to monitor the volume in the production tubing above the downhole safety valve
   3. The downhole safety valve shall be closed and tested in the direction of flow potential
   4. The BHA will be handled with a quick release drop table to allow it to be dropped below the xmas tree at any time

10.3.3 Notes

a) A tool catcher, tool trap or similar device should be used to protect the valve below against damage in the event of accidentally pulling the cable out of the cable head during operation.

b) It is acceptable to use another hydraulically remotely operated valve, e.g., the HMV, to replace the WL safety head, provided the valve has documented wire cutting and sealing capabilities according to Norsok D-002.

c) A double-valve kill inlet connection shall be included in the rig-up. The kill line itself is not required. The valves shall be capable of holding pressure in both directions. The inner valve shall be flanged and have metal to metal seal. The production tree kill wing valve may be used as the inner valve. Both valves shall be leak tested in the direction of flow. A bleed off/pressure monitoring port between the valves or a tested blind cap with bleed off/pressure monitoring port shall be installed. If neither of the valves are remotely controlled, a check valve shall be installed whenever connecting a kill line.

d) When rigging up on a well where the primary well barrier (SCSSV) has failed, the WL safety head shall be installed and tested prior to continuing to R/U the remaining wireline well control equipment. If another valve, e.g., a HMV with documented wire cutting capability, is used as WL safety head, then both the primary and secondary barriers shall be tested prior to rigging up.

e) The riser/lubricator length between the surface production tree and the WL safety head shall be as short as possible. If the WL BOP is installed high in the rig up configuration (e.g., when rigging up the WL BOP on drill floor) a separate WL safety head shall be installed close to the surface production tree.

f) The number of riser/lubricator connections between the surface production tree and the WL BOP/ WL safety head are critical and should be kept to a minimum.
g) All tools or components that the WL safety head may not be able to cut shall be identified prior to start of operation. Contingency procedures and compensating measures shall be in place for how to act when such tools or components are positioned across the WL safety head (ref. 10.4.4 and 10.4.5).

h) The shear/seal ram in the LRP is defined as the upper closure device in the secondary well barrier whenever running wireline in completed SSWs. The same shear/seal requirements therefore apply to the LRP shear/seal ram as to the WL safety head.

i) The shear/seal ram in the subsea drilling BOP is defined as the upper closure device in the secondary well barrier whenever a subsea drilling BOP is installed when running wireline in sub-sea wells. The same requirements therefore apply to the drilling BOP shear/seal ram as to the WL safety head.

10.4 Well barrier elements acceptance criteria

The following table describes requirements and guidelines which are additional to what is described in Section 15.

<table>
<thead>
<tr>
<th>No.</th>
<th>Element name</th>
<th>Additional features, requirements and guidelines</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Subsea test tree.</td>
<td>The function of the SSTT is to seal off the test string or workover riser with or without wireline present. The lower valve in the SSTT shall be capable of shearing any cable or slickline inside. The upper valve shall be capable of obtaining and maintaining a pressure seal. The SSTT valves are back-up elements in the primary well barrier, i.e. when the SCSSV is not available the SSTT valves will constitute the upper closure device in the primary well barrier after a disconnect. When the riser is connected, the combination of SSTT valves and subsea drilling BOP pipe ram are back-up elements in the secondary well barrier, i.e. to the sub-sea drilling BOP shear/seal ram.</td>
</tr>
</tbody>
</table>

10.4.1 Potential for compromised well barrier elements – probability reducing measures

Certain types of wireline operations present a higher than normal probability of getting stuck with non-shearable components across WBEs or near surface and/or with increased risk of cut cable not falling below the tree valves. For example running and retrieving large OD / close tolerance plugs and valves (such as wireline retrievable insert safety valves), milling scale deposits close to surface, etc.

For these types of operations there shall be a specific focus in the operational risk analysis and specific measures should be implemented to reduce the probability of getting stuck in critical areas of the well and/or surface well control system. Some potential measures that should be evaluated include:

- Prior to running and retrieving of close tolerance assemblies the internal diameter of the entire well control stack and wellbore, above the setting/retrieving point in the well, should be physically verified by means of a drift and/or caliper run.
- Prior to running any close tolerance assemblies the maximum diameter(s) on the assembly should be physically verified.
- Prior to retrieving any close tolerance assembly from the well all diameters, lengths, shoulders, etc. should be identified and verified by means of technical documentation records. Any potential increase in OD from original design (e.g. due to deformation or swelling) should be identified and included in the risk analysis for the operation.
- When retrieving (or running) close tolerance assemblies any indications of unexpected drag forces should be evaluated immediately from a risk perspective prior to entering critical areas in the well/rig-up.
- Evaluate the potential for tools to block the wellbore and compromise well killing operations.
10.4.2 Potential for compromised well barrier elements – consequence reducing measures

Where the residual risk is still considered to be unacceptably high measures should be implemented to mitigate the consequences in the event of becoming stuck. Some potential measures that should be evaluated include:

- Include programmable disconnects in the toolstring to allow disconnect and closure of WBE in the event of becoming stuck
- Include or verify shearable sections at strategic positions in the toolstring
- Include additional closure devices in the well control configuration (e.g., an additional shear/seal ram higher up in the configuration).
- Use flanged connections below the safety head (e.g., to provide enhanced integrity in cases where cut cable may not drop below the xmas tree valves).
- Complete well kill equipment and materials available and/or rigged up for immediate availability

10.5 Well control action procedures and drills

10.5.1 Well control action procedures

The following table describes incident scenarios for which well control action procedures should be available. This list is not comprehensive and additional scenarios may be included based on the planned activities.

<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>Loss of power air/electricity supply during operation.</td>
<td>Fixed and floating installation.</td>
</tr>
<tr>
<td>2.</td>
<td>Loss of winch power or mechanical failure.</td>
<td>Fixed and floating installation.</td>
</tr>
<tr>
<td>5.</td>
<td>External leak below WL BOP safety head.</td>
<td>Fixed and floating installation.</td>
</tr>
<tr>
<td>7.</td>
<td>Leak in stuffing box/grease head.</td>
<td>Fixed and floating installation.</td>
</tr>
<tr>
<td>10.</td>
<td>Leak in the surface production tree hydraulic master valve while lubricating against swab valve.</td>
<td>Fixed installation.</td>
</tr>
<tr>
<td>11.</td>
<td>Leak in lubricator valve while lubricating against lubricator valve.</td>
<td>Floating installation.</td>
</tr>
<tr>
<td>12.</td>
<td>Leak in test string below SSTT.</td>
<td>Floating installation.</td>
</tr>
<tr>
<td>14.</td>
<td>External leak in riser above or below LRP.</td>
<td>Floating installation.</td>
</tr>
<tr>
<td>15.</td>
<td>Controlled disconnect.</td>
<td>Floating installation.</td>
</tr>
<tr>
<td>16.</td>
<td>Emergency disconnect.</td>
<td>Floating installation</td>
</tr>
<tr>
<td>17.</td>
<td>Emergency situation on rig/platform.</td>
<td>Fixed and floating installation.</td>
</tr>
<tr>
<td>18.</td>
<td>Influx in well during logging on wireline.</td>
<td>Logging without pressure control equipment on fixed and floating installation.</td>
</tr>
<tr>
<td>19.</td>
<td>Influx in well during wireline pipe conveyed logging with side entry sub above drilling BOP.</td>
<td>Logging without pressure control equipment on fixed and floating installation.</td>
</tr>
<tr>
<td>20.</td>
<td>Influx in well during wireline pipe conveyed logging with side entry sub below drilling BOP.</td>
<td>Logging without pressure control equipment on fixed and floating installation.</td>
</tr>
</tbody>
</table>
10.5.2 Well control action drills
The following well control action drills should be performed:

<table>
<thead>
<tr>
<th>Type</th>
<th>Frequency</th>
<th>Objective</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well control action procedure, see 10.5.1.</td>
<td>Once per week for both day and night shift.</td>
<td>Response training.</td>
<td>The selected procedure shall be relevant for the ongoing operation.</td>
</tr>
</tbody>
</table>

10.6 Other topics

10.6.1 Hydrate prevention
A hydrate-inhibiting fluid shall be used whenever there is a risk for forming of hydrates during operation.

10.7 Examples of well barrier schematic illustrations
The following well barrier schematics are guidelines and describe one possible solution for how the well barrier envelopes with well barrier elements can be established and illustrated.

HOLD: Insert new WBS here