6 WELL TESTING ACTIVITIES ................................................................................................................................. 2

6.1 GENERAL .................................................................................................................................................................. 2
6.2 WELL BARRIER SCHEMATICS ................................................................................................................................. 2
6.3 WELL BARRIER ACCEPTANCE CRITERIA .................................................................................................................. 2
6.4 WELL BARRIER ELEMENTS ACCEPTANCE CRITERIA ............................................................................................ 2
6.5 WELL CONTROL ACTION PROCEDURES AND DRILLS .......................................................................................... 3
   6.5.1 Well control action procedures ................................................................................................................... 3
   6.5.2 Well control drills ........................................................................................................................................ 3
6.6 WELL TEST DESIGN ............................................................................................................................................... 3
   6.6.1 General ........................................................................................................................................................ 3
   6.6.2 Design basis, premises and assumptions .................................................................................................... 3
   6.6.3 Load cases ................................................................................................................................................... 4
   6.6.4 Minimum design factors ............................................................................................................................. 4
6.7 OTHER TOPICS ....................................................................................................................................................... 4
   6.7.1 Process and emergency shut-down system ................................................................................................ 4
   6.7.2 Hydrate prevention ..................................................................................................................................... 4
   6.7.3 Well testing with underbalanced annulus fluid .......................................................................................... 5
   6.7.4 Deep water well testing .............................................................................................................................. 5
   6.7.5 On-site pre-test meeting ............................................................................................................................. 5
   6.7.6 Disconnecting the subsea test tree (SSTT) ................................................................................................. 5
6.8 EXAMPLES OF WELL BARRIER SCHEMATIC ILLUSTRATIONS ............................................................................. 6
6 Well testing activities

6.1 General
This section covers requirements and guidelines pertaining to well integrity during well testing. The activity starts after having drilled and logged the last open hole section. The activity concludes when the well has been killed and the test string has been recovered.

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.

6.2 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 (6.8).

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

a) It shall be possible to close the test string at the BOP level. For subsea operations it shall also be possible to disconnect the test string below the blind/shear rams.

b) It shall be possible to shear the landing string/tubing and seal the wellbore.

c) It shall be possible to kill the well by circulating kill fluid via the STT using the fluid pump or high pressure (cement) pump, with returns through the rig's choke manifold and fluid or gas separator.

d) It shall be possible to establish a circulation path, via the test string at all times.

6.4 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>Table no.</th>
<th>Element name</th>
<th>Additional features, requirements and guidelines</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Fluid column</td>
<td>When annular fluids with kill weight density are used, a minimum of 50% additional well volume of the same or alternative fluid shall be available on site. The trip tank level shall be monitored continuously.</td>
</tr>
</tbody>
</table>
| 4         | Drilling BOP          | Shall have sufficient height and ram configuration to accommodate a SSTT (or safety valve for jack-ups) whilst allowing closure of two rams (lower, middle ram is used, with lower ram as back up) around the slick joint. It may be necessary to utilise an annular as the second ram on Jack-up rigs where the configuration does not permit closure of two pipe rams. Ported slick joints would be required in this case
Shall have the ability to close the shear/seal ram above the SSTT valve in a connected configuration (with latch attached to valve). Elastomers in the BOP stack shall have a documented ability to withstand the maximum expected temperature. |
| 22        | Casing / Liner cement | When planning to set the well test packer inside a liner it shall be verified by pressure testing that the liner lap has sufficient pressure retaining capacity to withstand the maximum differential pressure exercised by the fluid column and a leaking tubing scenario. |
| 43        | Liner top packer      |                                                                                                                                 |

NORSOK standard
6.5 Well control action procedures and drills

6.5.1 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>Inflow or fluid loss while running or pulling test string</td>
<td>A stab-in (tubing) safety valve made up to the necessary x-over(s) to the string shall be prepared and made ready for use at all times</td>
</tr>
<tr>
<td>2.</td>
<td>Tubing leak</td>
<td>Decision tree showing required actions in relation to leak location shall be prepared and reviewed at the well site prior to commencement of well test operations</td>
</tr>
<tr>
<td>3.</td>
<td>Disconnect SSTT</td>
<td>Criteria for maximum heave, riser angle and pitch/roll should be described. The time from activating valve closure until latch assembly is released should be documented and used in the unlatching procedure. It should be possible to raise the latch assembly above the LMRP disconnect point without having to break connections at the rig floor. For dynamic positioned vessels, operating criteria shall be described for drift / drive-off situations, with defined actions.</td>
</tr>
<tr>
<td>4.</td>
<td>Presence of H₂S</td>
<td>Material selection for downhole and surface equipment shall account for the potential of H₂S. Criteria for when to implement contingency measures or abort the test should be established.</td>
</tr>
<tr>
<td>5.</td>
<td>Killing the well</td>
<td>Planned and contingency kill methods should be documented</td>
</tr>
</tbody>
</table>

Tool pusher or driller and drill stem test tool or SSTT operator shall be on rig floor at all times, during the well test phase.

6.5.2 Well control 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>Disconnect of the SSTT</td>
<td>Once per crew as soon as practical after rig-up.</td>
<td>Response training.</td>
<td>Without physically disconnecting the SSTT (working through all the steps required for planned and emergency disconnect).</td>
</tr>
<tr>
<td>Major leak above the seabed</td>
<td>Once per crew as soon as practical after rig-up.</td>
<td>Response training.</td>
<td>Following decision tree’s included in well programme</td>
</tr>
</tbody>
</table>

6.6 Well test design

6.6.1 General
The selection of well testing operational methods, procedures and equipment shall be determined by considerations of safety and risk to the environment, operational efficiency and cost effectiveness. The well test operations procedure shall define and specify limitations and well barriers.

6.6.2 Design basis, premises and assumptions
See NORSOK D-007.
6.6.3 Load cases
All components of the test string shall be subject to load case verification. Design calculations should be performed using recognized methods, e.g. industry recognized software. Axial and tri-axial loads shall be calculated and checked against tubing and test string component strength. The weakest point in the test string shall be clearly identified with regards to burst, collapse and tensile rating.

METP shall be determined and should consider;

1. maximum expected fracture pressure,
2. maximum pressure to fire TCP guns,
3. maximum expected bullhead kill pressure (shut-in tubing pressure +70 bar).

For thermal tubing, the stress loads should be calculated using the inner pipe, disregarding the outer pipe.

The following load cases shall be considered. This list is not comprehensive and actual cases based on the planned activity shall be performed:

<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>Test string collapse at depth; shut-in tubing pressure above annulus fluid hydrostatic (tubing leak below wellhead)</td>
<td>Apply highest case annulus pressure on top of annulus fluid column (applied pressure or tubing leak) Assume lightest fluid gradient inside tubing (dry gas if applicable)</td>
</tr>
<tr>
<td>2.</td>
<td>Casing / liner collapse below packer where test string is evacuated</td>
<td></td>
</tr>
<tr>
<td>3.</td>
<td>Burst at surface and below wellhead when pressure testing string.</td>
<td>Apply maximum expected test or bullheading pressure with weight of string below wellhead for the tubing side and zero pressure on the annulus side.</td>
</tr>
<tr>
<td>4.</td>
<td>Pulling load at surface when attempting to release a stuck test string.</td>
<td>Apply necessary pull for parting string at weak point plus 20 % with string weight not corrected for buoyancy.</td>
</tr>
<tr>
<td>5.</td>
<td>Tubing movement.</td>
<td>Pressure testing, production, shut-in and killing with cold fluid. Apply maximum expected bullheading pressure at cold temperature on the tubing side with zero annulus pressure.</td>
</tr>
</tbody>
</table>

6.6.4 Minimum design factors
For deterministic calculations of loads and ratings, these design factors should apply:

a) Burst: 1,10
b) Collapse: 1,10
c) Axial: 1,25 or 1,50 for over-pull loads (pulling the packer free after the test).
d) Tri-axial yield: 1,25 Pipe body and connection whichever combination is weaker.

6.7 Other topics

6.7.1 Process and emergency shut-down system
An emergency shut-down and disconnect plan shall be established and be made subject to a review by all involved parties. The plan shall include automatic and manual actions and contingency procedures.

6.7.2 Hydrate prevention
Chemical injection shall be available at critical points in the test string and at surface. Actions for preventing and removing hydrates should be included in the procedures. Annulus fluid selection should consider the risk of hydrate formation in the case of a tubing leak or discharge of hydrocarbons into the marine riser during a SSTT unlatch.
6.7.3 Well testing with underbalanced annulus fluid

An inflow test of the production liner, liner lap and shoe shall be conducted prior to displacing the overbalanced well fluid. The following apply:

a) The inflow test value should include a safety margin, which can be achieved by utilising fluids lighter than the packer fluid during the inflow test.

b) The inflow test acceptance criteria should account for thermal effects.

c) The production casing shall be pressure tested to maximum expected pressure (i.e METP) using the packer fluid.

d) The well test packer shall be pressure tested from below to maximum expected differential +10%.

e) Kill fluid shall be readily available in tanks for displacement of the entire well volume +50%.

6.7.4 Deep water well testing

The increased risk of process problems (hydrates, wax, and asphalitines) due to the cooling effect in deep water should be evaluated. Annulus fluid selection should consider the thermal conductivity of fluid’s and their ability to maximise flowing temperature at wellhead depth.

The SSTT temperature should be monitored during testing.

6.7.5 On-site pre-test meeting

A pre-test meeting shall be conducted with all involved personnel, addressing the following items:

a) Outline Well Test Design.

b) Expected pressure, temperature and flowrates.

c) Expected duration of operations.

d) Contingency reactions.

e) Risk analysis results.

f) Well test PSD system description and function.

g) Rig ESD system description.

h) Explanation of organization and responsibilities.

i) Enforcing of special safety restrictions (smoking, welding, grinding, use of open flame and areas with no access).

j) Locations of manual PSD and ESD buttons.

k) Locations of fire fighting equipment.

l) Pollution and oil spill actions.

6.7.6 Disconnecting the subsea test tree

When testing on floating vessels, procedures and plans pertaining to disconnect (planned and emergency) of the SSTT and drilling riser shall be reviewed by all involved parties.

If the test string needs to be disconnected and time permits (planned), one of the following methods should be applied:

1. Close the downhole tester valve, open the circulating valve and circulate kill fluid into the string. (Overbalanced annulus cases only), or

2. bullhead the string or landing string content into the formation, or

3. close the downhole tester valve and SSTT. Inflow test the SSTT prior to disconnect.
If time does not permit, an emergency disconnect should be initiated. Emergency disconnect procedures shall be documented and reviewed by all involved parties.

The risk of environmental spills during a disconnect should be assessed. Consideration should be given to the use of a retainer valve above the SSTT.

6.8 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 – WBS to be inserted here.*