NORSOK STANDARD D-010

Rev. 3, August 2004

Well integrity in drilling and well operations

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Foreword

The NORSOK standards are developed by the Norwegian petroleum industry to ensure adequate safety, value adding and cost effectiveness for petroleum industry developments and operations. Furthermore, NORSOK standards are as far as possible intended to replace oil company specifications and serve as references in the authorities' regulations.

The NORSOK standards are normally based on recognised international standards, adding the provisions deemed necessary to fill the broad needs of the Norwegian petroleum industry. Where relevant NORSOK standards will be used to provide the Norwegian industry input to the international standardisation process. Subject to development and publication of international standards, the relevant NORSOK standard will be withdrawn.

The NORSOK standards are developed according to the consensus principle generally applicable standards work and according to established procedures defined in NORSOK A-001.

The NORSOK standards are prepared and published with support by The Norwegian Oil Industry Association (OLF) and Federation of Norwegian Manufacturing Industries (TBL). NORSOK standards are administered and published by Standards Norway.

Introduction

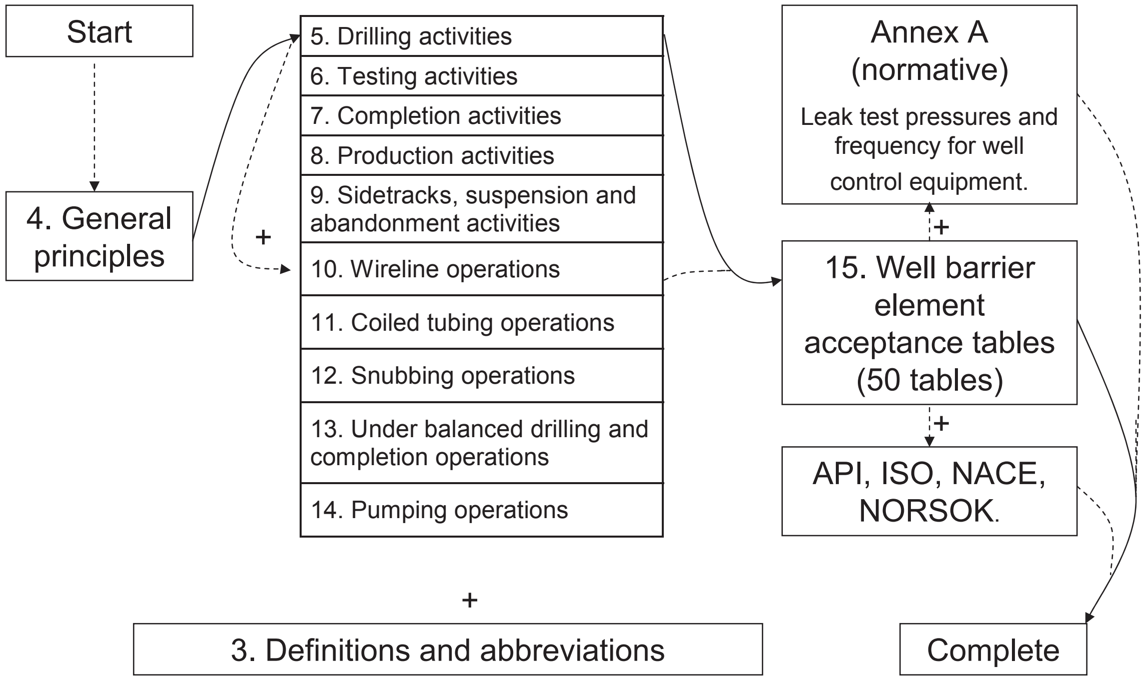
This revision was initiated to make this NORSOK standard compliant with changes in legislation and adapted to evolving and new technology. In this revision, the user will find that the standard has been completely reorganised and that the content and structure is different than the previous revision. The intention has been to make it easier to find information and provide flexibility to updating or revising this NORSOK standard in the future without altering its structure. Consequently, the changes from the previous revision are not marked.

The following main changes are implemented in this revision:

- The focus of this NORSOK standard is well integrity, which is the application of technical, operational and organizational solutions to reduce the risk of uncontrolled release of formation fluids throughout the entire life cycle of the well and of course safety aspects. Recommendations for best practices are not dominant. This led to renaming this NORSOK standard to "Well integrity in drilling and well operations".
- The descriptions are mostly insensitive to type of well and type of installation.
- Clear and concise requirements (shall) and guidelines (should) have been applied to stress their importance and to differentiate the process of handling deviations from these.
- Overlapping or duplication of text or topics in other standards has been minimized.
- Well barrier related terminology with definitions has been established in lack of apparent international standard definitions.
- Pre-defined WBSs for most common situations have been included.
- A library of 50 defined WBEs with acceptance criteria has been added, which the user can apply to define a well barrier with associated standard acceptance criteria.
- Listings of situations for which well control action procedures should be in place are included.
- Underbalanced drilling and completion operations and sidetracking, plugging and abandonment activities are significantly altered.
- Production activities and pumping operations are new.

The user is encouraged to study the following "roadmap to understanding" to get a quick overview of how this NORSOK standard is structured and how to obtain the "full" overview of related requirements and guidelines:

Road Map to Understanding



1 Scope

This NORSOK standard focus on well integrity by defining the minimum functional and performance oriented requirements and guidelines for well design, planning and execution of well operations in Norway.

2 Normative and informative references

The following standards include provisions and guidelines which, through reference in this text, constitute provisions and guidelines of this NORSOK standard. Latest issue of the references shall be used unless otherwise agreed. Other recognized standards may be used provided it can be shown that they meet or exceed the requirements and guidelines of the standards referenced below.

2.1 Normative references

ISO 10405,	*Petroleum and natural gas industries – Care and use of casing and tubing.*
ISO 10414-1,	*Petroleum and natural gas industries – Field testing of drilling fluids – Part 1: Water-based fluids.*
ISO 10414-2,	*Petroleum and natural gas industries – Field testing of drilling fluids – Part 2: Oil-based fluids.*
ISO 10416,	*Petroleum and natural gas industries – Drilling fluids laboratory testing.*
ISO 10417,	*Petroleum and natural gas industries – Subsurface safety valve systems – Design, installation, operation and repair.*
ISO 10423,	*Petroleum and natural gas industries – Drilling and production equipment – Wellhead and Christmas tree equipment.*
ISO 10426-1,	*Petroleum and natural gas industries – Cements and materials for well cementing – Part 1: Specification.*
ISO 10432:1999,	*Petroleum and natural gas industries – Downhole equipment – Subsurface safety valve equipment.*
ISO 11960,	*Petroleum and natural gas industries – Steel pipes for use as casing or tubing for wells.*
ISO 11961,	*Petroleum and natural gas industries – Steel pipes for use as drill pipe – Specification.*
ISO 13533,	*Petroleum and natural gas industries – Drilling and production equipment – Drill-through equipment.*
ISO 13628-4,	*Petroleum and natural gas industries – Design and operation of subsea production systems – Part 4: Subsea wellhead and tree equipment.*
ISO/DIS 13628-7,	*Petroleum and natural gas industries – Design and operation of subsea production systems – Part 7: Completion/workover riser systems.*
ISO 14310,	*Petroleum and natural gas industries – Down hole equipment – Packers and bridge plugs.*
ISO 15156-1,	*Petroleum and natural gas industries – Materials for use in H_2S-containing environments in oil and gas production – Part 1: General principles for selection of cracking-resistant materials.*
API Bull 5C2,	*Performance Properties of Casing, Tubing, and Drill Pipe.*
API Bull 5C3,	*Formulas and Calculations for Casing, Tubing, Drill Pipe, and Line Pipe Properties.*
API RP 5C7,	*Coiled Tubing Operations in Oil and Gas Well Services.*
API RP 7G,	*Drill Stem Design and Operation Limits.*
API RP 14B,	*Design, Installation, Repair and Operation of Subsurface Safety Valve Systems.*
API RP 53,	*Blowout Prevention Equipment Systems for Drilling Operations.*
API Spec 6FA,	*Fire Test for Valves.*
API Spec 6FB,	*Fire Test for End Connections.*
API Spec 6FC,	*Fire Test for Valve With Automatic Backseats.*
API Spec. 7,	*Rotary Drill Stem Elements.*
ASTM D412,	*Standard test Methods for Vulcanized Rubber and Thermoplastic Elastometers – Tension 1.*
ASTM D471,	*Standard Test Method for Rubber Property – Effect of Liquids 1.*
ASTM D2240,	*Standard Test Method for Rubber Property – Durometer Hardness 1.*

ASTM G111,	*Standard Guide for Corrosion Tests in High Temperature or High Pressure Environment.*
NORSOK D-001,	*Drilling facilities.*
NORSOK D-002,	*System requirements well intervention equipment.*
NORSOK D-SR-007,	*Well testing system.*
NORSOK R-003N,	*Sikker bruk av løfteutstyr.* (English version will be issued later)
NORSOK S-001,	*Technical safety.*
NORSOK Z-013,	*Risk and emergency preparedness analysis.*
OLF/NR's, No.024,	*Recommendations for Training of Drilling and Well Service Personnel.*

2.2 Informative references

None.

3 Terms, definitions and abbreviations

For the purposes of this NORSOK standard the following terms, definitions and abbreviations apply.

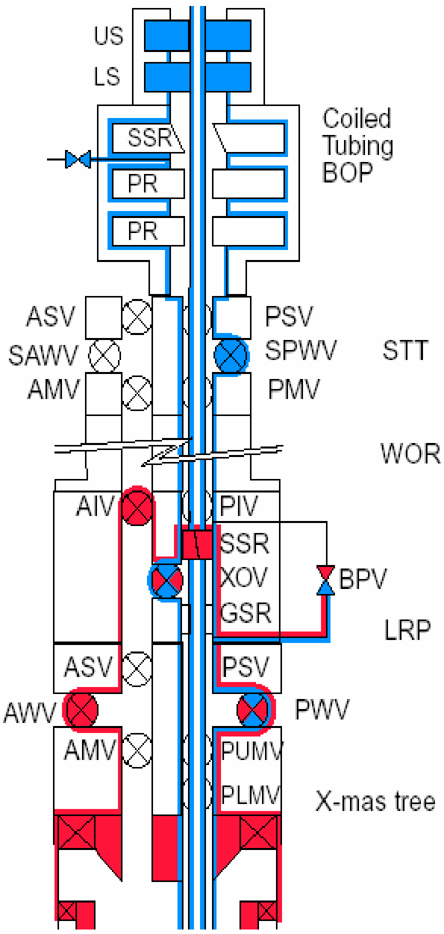
The terminology used in this NORSOK standard for well barriers is based on:

Primary well barrier:
This is the first object that prevents flow from a source.
Example - blue items: Strippers + CT BOP+ surface test tree,+++

Secondary well barrier:
This is the second object that prevents flow from a source.
Example - red items: Lower riser package + production tree + wellhead,+++

Well barrier element:
An object that alone can not prevent flow from one side to the other side of itself.
Example: CT BOP

Common well barrier element:
This is a barrier element that is shared between primary and secondary barrier.
Examples: Body of LRP, X.mas tree and production wing valve



Working well barrier stage:
This is the stage which shows the well barrier elements that are used to confine the pressure in a normal working mode.
Example: Closed CT strippers + CT body + surface test tree w. closed wing valve, +++

Intermediate well barrier stage:
This is the stage(s) of a well barrier element activation sequence before the ultimate well barrier stage is reached.
Examples:
Leak in CT strippers – close CT pipe rams.

Ultimate well barrier stage:
This is the final stage of a well barrier element activation sequence which normally includes closing a shearing device.
Example: Closed CT shear ram (primary barrier) or closed master valve (secondary barrier),+++

3.1 Terms and definitions

3.1.1
A-annulus
annuli between the tubing and the production casing

3.1.2
abnormally pressured
means that the formation/reservoir pressure exceeds the hydrostatic pressure of a seawater column with reference to LAT

3.1.3
activity
preparation for and implementation of operations

3.1.4
B-annulus
annuli between the production casing and the previous casing string

3.1.5
can
verbal form used for statements of possibility and capability, whether material, physical or casual.

3.1.6
common well barrier element
barrier element that is shared between the primary and secondary well barrier

3.1.7
critical
activity or operation that potentially can cause serious injury or death to people, or significant pollution of the environment or substantial financial losses

3.1.8
deep water well
water depth exceeding 600 m LAT

3.1.9
design factor
ratio between the rated strength of the material over the estimated load

3.1.10
discharge line
line between the pump that is used for pumping and the first permanent valve on a WBE

Examples - Surface production tree, wellhead.

3.1.11
electrical cable
wire consisting of individual steel strands woven around one or more electrical conductors to provide sufficient strength to perform desired electrical work in a well

3.1.12
energised fluids
liquefied gases or liquid containing gases

3.1.13
HPHT well
high pressure and high temperature well with expected shut-in pressure exceeding 69 MPa, or a static bottomhole temperature higher than 150 ^{o}C

3.1.14
kick tolerance
maximum influx to equal MAASP

Note - MAASP is based on weakest zone in the wellbore, normally assumed to be at casing shoe.

3.1.15
leak testing
application of pressure to detect leaks in a well barrier, WBE or other objects that are designed to confine pressurised fluids (liquid or gas)

3.1.16
low head drilling
drilling operation where the dynamic bottom-hole pressure in the well bore is equal to or slightly higher than the pore pressure of the formation being drilled

3.1.17
may
verbal form used to indicate a course of action permissible within the limits of the standard

3.1.18
operation
sequence of planning and execution tasks that are carried out to complete a specific activity

3.1.19
permanent abandonment
well status, where the well or part of the well, will be plugged and abandoned permanently, and with the intention of never being used or re-entered again

3.1.20
permanent well barrier
well barrier consisting of WBEs that individually or in combination creates a seal that has a permanent/eternal characteristic

3.1.21
pipe light
tripping mode where pressure forces acting upwards on the cross sectional area of the work string is larger than the weight of the string

3.1.22
plug
“cement” plug (see Table 24) or mechanical plug

3.1.23
plugging
operation of securing a well by installing required well barriers

3.1.24
potential source of inflow
formation with permeability, but not necessarily a reservoir

3.1.25
pressure testing
application of pressure to a value that equals or exceeds the item or system WP to confirm its pressure integrity at rated WP

3.1.26
primary well barrier
first object that prevents flow from a source

3.1.27
procedure
series of steps that describes the execution of a task or piece of work

3.1.28
production operation
organizational unit that is responsible for the integrity of the well during production

3.1.29
pumping
injection or flow of a fluid from a surface reservoir and into the well

3.1.30
reservoir
permeable formation or group of formation zones originally within the same pressure regime, with a flow potential and/or hydrocarbons present or likely to be present in the future

3.1.31
riser margin
additional fluid density to add to the hole below the mudline required to compensate for the differential pressure between the fluid in the riser and seawater in the event of a riser disconnect

3.1.32
secondary well barrier
second object that prevents flow from a source

3.1.33
shall
verbal form used to indicate requirements strictly to be followed in order to conform to the standard and from which no deviation is permitted, unless accepted by all involved parties

Note - The deviation process for handling of deviations and non-conformity with “shall” requirements and “should” guidelines in this NORSOK standard shall be in accordance with responsible party’s system for handling of deviations. These systems shall describe procedures for how to deviate from requirements and guidelines listed in the regulatory regulations with guidelines and the responsible party’s steering documentation.

3.1.34
shallow gas
free gas or gas in solution that exists in permeable formation which is penetrated before the surface casing and BOP has been installed

Note - The gas can be normally pressured or abnormally pressured.

3.1.35
should
verbal form used to indicate that among several possibilities one is recommended as particularly suitable, without mentioning or excluding others, or that a certain course of action is preferred but not necessarily required

Note - The deviation process for handling of deviations and non-conformity with “shall” requirements and “should” guidelines in this NORSOK standard should be in accordance with responsible party’s system for handling of deviations. It is assumed that these systems describe procedures for how to deviate from requirements and guidelines listed in the regulations with guidelines and the responsible party’s steering documentation.

3.1.36
simultaneous activities
activities that are executed concurrently on a platform or unit, such as production activities, drilling and well activities, maintenance and modification activities and critical activities

3.1.37
slickline
slick string of uniform diameter with sufficient strength to convey WL tools to their operating depth

3.1.38
suspension
well status, where the well operation is suspended without removing the well control equipment.

Example - Rig skidded to do short term work on another well, strike, rough weather conditions, waiting on equipment, etc.

3.1.39
surface casing
the last casing installed prior to drilling into an abnormally pressured formation or a formation containing hydrocarbons.

3.1.40
temporary abandonment
well status, where the well is abandoned and/or the well control equipment is removed, with the intention that the operation will be resumed within a specified time frame (from days up to several years).

Example - Pulling BOP for repair, re-entry at a later stage to perform sidetrack - or well test, skidding rig to do higher priority well work, assessment of well data and converting a well from an exploration to a development well, etc.

3.1.41
through tubing drilling and completion
drilling and completing operations conducted through the in situ tubing

3.1.42
trip margin
incremental increase in drilling fluid density to provide an increment of overbalance in order to compensate for effects of swabbing

3.1.43
ultimate well barrier stage
final stage of a WBE activation sequence which normally includes closing a shearing device

Note - This stage normally describes the use of a shearing device.

3.1.44
under balanced drilling
UBD
drilling operation where the dynamic bottom-hole pressure in the well bore is intentionally lower than the pore pressure of the formation being drilled

3.1.45
well barrier
envelope of one or several dependent barrier elements preventing fluids or gases from flowing unintentionally from the formation, into another formation or to surface

3.1.46
well barrier element
WBE
object that alone can not prevent flow from one side to the other side of it self

3.1.47
well control
collective expression for all measures that can be applied to prevent uncontrolled release of well bore effluents to the external environment or uncontrolled underground flow

3.1.48
well control action procedure
specified sequence of planned actions/steps to be executed when the primary well barrier fails

Note - This normally describes the activation of the secondary well barrier, e.g. shut in of well.

3.1.49
well construction team
organizational unit that has drilled and completed the well

3.1.50
well influx/inflow (kick)
unintentional inflow of formation fluid from the formation into the wellbore

3.1.51
well integrity
application of technical, operational and organisational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well

3.1.52
well intervention
collective expression for deployment of tools and equipment in a completed well.

Example - Coiled tubing, wireline and snubbing operations.

3.2 Abbreviations

AMV	annulus master valve
ASCSSV	annulus surface controlled sub-surface valve
BHA	bottom hole assembly
BHP	bottom hole pressure
BOP	blow out preventer
BPV	back pressure valve
CT	coiled tubing
DIV	downhole isolation valve
DP	dynamically positioned
ECD	equivalent circulating density
ESD	emergency shut down
ESDV	emergency shut down valve
HPHT	high pressure high temperature
HSE	health, safety and environment
ID	internal diameter
LAT	low astronomical tide
LHD	low head drilling
LMRP	lower marine riser package
LRP	lower riser package
LWD	logging while drilling
MAASP	maximum allowable annulus surface pressure
MEDP	maximum expected design pressure
METP	maximum expected tubing pressure
MD	measured depth
MPI	magnetic particle inspection
MSDP	maximum section design pressure
MWDP	maximum well design pressure
NRV	non-return valve
OD	outer diameter
PMV	production master valve
PSD	production shut down
PWV	production wing valve
RCD	rotating control device
R/D	rig down
RIH	running in hole
ROV	remote operated vehicle
R/U	rig up
SCSSV	surface controlled subsurface safety valve
SPWV	subsea production wing valve
SSR	shear-seal ram
SSTT	subsea test tree

SSW	subsea well
STT	surface test tree
TCP	tubing conveyed perforating
TOC	top of cement
TSTP	tubing string test pressure
UB	under balanced
UBD	under balanced drilling
UBO	under balanced operation
WBE	well barrier element
WBEAC	well barrier element acceptance criteria
WBS	well barrier schematic
WHP	well head pressure
WL	wire line
WP	working pressure
XOV	cross-over valve

4 General principles

4.1 General

This clause describes generic principles, requirements and guidelines relating to well activities and operations which are applicable to the specific well activities and operations described in the clauses to follow.

If there is a conflict between Clause 4 and the following clauses, the latter shall apply.

4.2 Well barriers

4.2.1 General

Well barriers are envelopes of one or several dependent WBEs preventing fluids or gases from flowing unintentionally from the formation, into another formation or to surface.

The well barrier(s) shall be defined prior to commencement of an activity or operation by description of the required WBEs to be in place and specific acceptance criteria.

4.2.2 Well barrier schematics

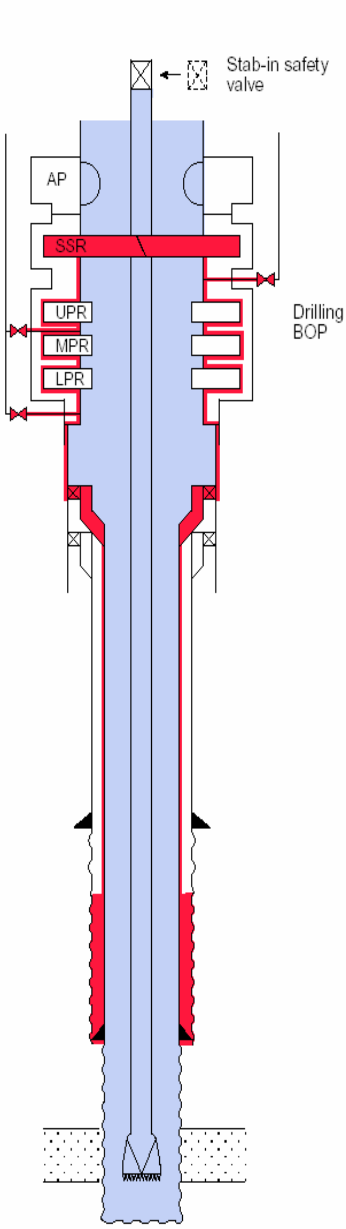
The samples of WBS presented in the sections to follow describe the

- primary well barrier in its normal working stage, which for some situations is the fluid column or a mechanical well barrier that provides closure of the well barrier envelope,
- secondary well barrier in its ultimate stage, which in most cases describes a situation where the shear ram/shear valve is closed.

Examples of WBSs are presented in this NORSOK standard for some selected situations. These WBSs are guidelines (should) and define the well barriers and their components (WBEs).

Example:

5) **Drilling, coring or tripping – Shearable drill string**



1) **Well barrier elements**	**See Table** *2)*	*3)* **Comments**
Primary well barrier		
1. Fluid column	1	
Secondary wellbarrier		
1. Casing cement	22	
2. Casing	2	Last casing set
3. Wellhead	5	
4. High pressure riser	26	If installed
5. Drilling BOP	4	

4) Note

Legend:

1. *This describes the name of the WBE(s)*
2. *A complete description of general acceptance criteria for this WBE is found in Clause 15 which contains a library of WBE acceptance criteria tables.*
3. *This table column is used to describe comments.*
4. *The place can be used for describing additional requirements and guidelines. For example a description of compensative measures if there exist common WBEs.*
5. *The illustration shows the primary well barrier in its normal working stage, while the secondary well barrier is shown in its ultimate stage. This stage often described with a closed shearing device.*

4.2.3 Well barrier acceptance criteria

4.2.3.1 General

Well barrier acceptance criteria are technical and operational requirements that need to be fulfilled in order to qualify the well barrier or WBE for its intended use.

4.2.3.2 Function and number of well barriers

The function of the well barrier and WBE shall be clearly defined.

There shall be one well barrier in place during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled cross flow in the wellbore between formation zones.

There shall be two well barriers available during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled outflow from the borehole/well to the external environment.

4.2.3.3 Well barrier design, selection and construction principles

The well barriers shall be designed, selected and/or constructed such that

- it can withstand the maximum anticipated differential pressure it may become exposed to,
- it can be leak tested and function tested or verified by other methods,
- no single failure of well barrier or WBE leads to uncontrolled outflow from the borehole / well to the external environment,
- re-establishment of a lost well barrier or another alternative well barrier can be done,
- it can operate competently and withstand the environment for which it may be exposed to over time,
- its physical location and integrity status of the well barrier is known at all times when such monitoring is possible.

The primary and secondary well barriers shall to the extent possible be independent of each other without common WBEs. If common WBEs exist, a risk analysis shall be performed and risk reducing/mitigation measures applied to reduce the risk as low as reasonable practicable.

One of the well barriers should have WBE(s) that can

- shear any tool that penetrates the well barrier and seal the wellbore after having sheared the tool. If this is not achievable, well barrier descriptions for operational situations which do not require shearing of tools shall be identified,
- seal the well bore with any size tool that penetrates the well barrier. If this is not achievable, well barrier descriptions for operational situations which require shearing of tools shall be identified.

4.2.3.4 Initial verification of the well barrier

When the well barrier has been constructed, its integrity and function shall be verified by means of

- leak testing by application of a differential pressure,
- functioned testing of WBEs that require activation,
- verification by other specified methods.

4.2.3.5 Leak testing of well barriers

4.2.3.5.1 General

Leak testing of well barriers or WBEs shall be performed

- before it can become exposed to pressure differentials,
- after replacement of pressure confining components of the well barrier,
- when there is a suspicion of a leak,
- when an element will become exposed to different pressure/load than it originally was designed for,
- routinely, see Clause 15.

4.2.3.5.2 Pressure direction

The pressure should be applied in the flow direction. If this is impractical, the pressure can be applied against the flow direction, providing that the WBE is constructed to seal in both flow directions or by reducing the pressure on the downstream side of the well barrier to the lowest practical pressure (inflow test).

4.2.3.5.3 Leak test pressure values and duration

A low pressure leak test to 1,5 MPa to 2 MPa for 5 min should be performed prior to high pressure leak testing.

The high pressure leak test value shall be equal to or exceed the maximum anticipated differential pressure that the WBE will become exposed to. Static leak test pressure shall be observed and recorded for minimum 10 min.

The above test values shall not exceed the rated WP of any WBE.

4.2.3.5.4 Acceptable leak rates

The acceptable leak rate shall be zero, unless specified otherwise.
For situations where the leak-rate cannot be monitored or measured, the criteria for maximum allowable pressure fluctuation shall be established.

4.2.3.5.5 Function testing of well barriers

A function test of the WBE(s) shall be performed

- after installation,
- after having been subjected to abnormal loads,
- after repairs,
- routinely, see Clause 15.

4.2.3.5.6 Documentation of leak and function testing of well barriers

All well integrity tests shall be documented and accepted by an authorized person. This authorized person can be the driller, tool-pusher, drilling and well intervention supervisor or the equipment and service provider's representative.

The chart and the test documentation should contain

- type of test,
- test pressure,
- test fluid,
- system or components tested,
- estimated volume of system pressurised,
- volume pumped and bled back,
- time and date.

4.2.3.6 Use of well barriers

Requirements and guidelines for proper use of a well barrier in order for it to maintain its function and prevent damage during execution of activities and operations shall be described.

4.2.3.7 Well barrier monitoring

All parameters relevant for preventing uncontrolled flow from the well shall be monitored.

Methods and frequency for verifying the condition of the well barrier/WBEs shall be defined and documented.

All instrumentation used for required monitoring of parameters shall be frequently checked and calibrated.

4.2.3.8 Well barrier impairment

Situations were the function of the well barrier is weakened, but are still acceptable should be defined.

4.2.4 Well barrier elements acceptance tables

General technical and operational requirements and guidelines relating to WBEs are collated in tables in Clause 15, which shall be applicable for all type of activities and operations. Additional requirements and guidelines or deviations to these general conditions will be further described in the sections to follow.

The methodology for defining the requirements/guidelines for WBEs is:

Features	Acceptance criteria	References
A. Description	*This describes the WBE in words.*	
B. Function	*This describes the main function of the WBE.*	
C. Design (capacity, rating, and function), construction and selection	*For WBEs that are constructed in the field (i.e. drilling fluid, cement), this should describe* • *design criteria, such as maximal load conditions that the WBE shall withstand and other functional requirements for the period that the WBE will be used,* • *construction requirements for how to actually construct the WBE or its sub-components, and will in most cases only consist of references to normative standards.* *For WBEs that are already manufactured, the focus should be on selection parameters for choosing the right equipment and how this is assembled in the field.*	*Name of specific references*
D. Initial test and verification	*This describes the methods for verifying that the WBE is ready for use after installation in/on the well and before it can be put into use or is accepted as part of well barrier system.*	
E. Use	*This describes proper use of the WBE in order for it to maintain its function and prevent damage to it during execution of activities and operations.*	
F. Monitoring (Regular surveillance, testing and verification)	*This describes the methods for verifying that the WBE continues to be intact and fulfils it design/selection criteria during use.*	
G. Failure modes	*This describes conditions that will impair (weaken or damage) the function of the WBE, which may lead to implementing corrective action or stopping the activity/operation.*	

4.2.5 Well control equipment and arrangements

4.2.5.1 General

The well control equipment and arrangement shall be according to NORSOK D-001 and NORSOK D-002.

Arrangement drawings and flow diagrams for well control equipment shall be easily accessible for operators of this equipment, such that it is possible to determine the position of a tubular joint relative to the shear rams/valves at all times. These drawings and flow diagrams should include

- geometrical description (location, size, distances to rig floor, distances between rams, etc.),
- operational limitations (pressure, temperature, type of fluid, flow rates, etc.),
- overview of the fluid circulation system (pump, including choke and kill manifold.

4.2.5.2 Well control equipment arrangement for HTHP wells

The installation shall be equipped with

- a failsafe-open, remotely operated valve in the overboard line,
- a cement line pressure gauge in the choke panel,

- a remote camera in the shaker house, with display in the driller's house,
- a choke /kill line glycol injection system.

High pressure and/or high temperature resistant WBEs/seals shall be installed as follows:

- choke and kill lines, including flexible line hoses and the choke and kill manifold,
- packing in the kelly cock/internal BOP,
- packing/seal in the marine riser and low pressure fluid return system for SSWs.

Flexible kill-/choke line hoses shall be inspected by the Vendor and pressure tested to MWDP prior to HPHT mode.

4.2.5.3 Well control equipment arrangement for deep water wells (only for SSWs)

The following apply:

a) The need to utilize a multiplex BOP control system to meet the closing time requirements shall be evaluated. If a multiplex system is used there is no requirement to activate the BOP control functions from the accumulator unit due to multiplex using electrical and not hydraulic signals.
b) The kill-/choke line ID shall be verified to give acceptable pressure loss to allow killing of the well at pre-defined kill rates. The kill-/choke line should not be less than 88,9 mm (3 1/2 in).
c) It shall be possible to monitor the shut-in casing pressure through the kill line when circulating out an influx by means of the work string/test tubing/tubing.
d) It should be possible to monitor BOP pressure and temperature (readable on surface via multiplex system).
e) It shall be possible to flush well head connector with antifreeze liquid solution by using the BOP accumulator bottles or with a ROV system or other methods.
f) A ROV hot-stab panel shall be mounted on the drilling BOP with the following functions:
    1) well head connector unlock;
    2) well head connector gasket release;
    3) glycol injection;
    4) BOP accumulator dump;
    5) close blind/shear ram (preferably the upper shear ram);
    6) close one set of pipe rams;
    7) activate ram locks.
g) A ROV hot-stab panel shall be mounted on the LMRP with the following functions:
    1) LMRP disconnect;
    2) gasket release system;
    3) LMRP accumulator dump.
h) Detailed riser verification analysis shall be performed with actual well data (i.e. weather data, current profiles, rig characteristics etc.) and should be verified by a 3rd party.
i) A simulated riser disconnect test shall be conducted with the relevant operational data.
j) The riser shall have the following:
    1) current meter;
    2) riser inclination measurement devices along the riser;
    3) riser tensioning system with an anti-recoil system to prevent riser damage during disconnection;
    4) flex joint wear bushing to reduce excessive flex joint wear.

and should have:
    1) riser fill-up valve.

k) Parameters that affect the stress situation of the riser should be systematically and frequently collected and assessed to provide an optimum rig position that minimizes the effects of static and dynamic loads.

4.2.6 Well control actions procedures and drills

In the event of a failure or loss of a well barrier, immediate measures shall be taken in order to prevent escalation of the situation by activating the secondary well barrier. The situation shall then be normalized by restoring the primary well barrier or establishing an alternative well barrier before activities/operations can be resumed.

There shall be a plan for activating well barrier(s)/WBEs (well control action procedure), prior to commencement of all well activities and operations. These plans shall be made known to the personnel involved.

Activation of the shear rams/shear valves or other shearing devices shall only take place when there is an emergency situation and no other options exist but to cut.

Regularly and realistic drills pertaining to ongoing or up-coming operations shall be conducted to train involved personnel in detection and prevention of loss of well barriers. The objective of the drill shall be pre-defined. The drills should be repeated with sufficient frequency to achieve the acceptable response.

4.2.7 Well barrier re-establishment

4.2.7.1 General

There shall be a plan that describes how a lost well barrier or an alternative well barrier can be re-established for the most likely incident scenarios.

4.2.7.2 Re-establishment of fluid well barrier

The methods for killing the well or re-establishing a fluid well barrier shall be defined and described prior to execution of activities where the fluid column is one of the well barriers or is defined to be a contingency well barrier.

There shall be procedures describing well killing by

- "Wait and Weight Method",
- "Driller's Method",
- "Volumetric Method",
- "Bullheading Method".

Parameters required for re-establishing the fluid well barrier shall be systematically recorded and updated ("Killsheet"), which should include:

Parameter	Description	When
Pump pressure	Circulation through the drill pipe at different slow flow rates.	• Drilling out of casing/liner. • Change in the tubular configuration (size, BHA configuration). • Change in fluid density or rheology. • Every 500 m MD of new formation drilled or every shift.
Pump pressure	Circulation down the drill pipe/test tubing/tubing and up the choke or kill line at different slow flow rates.	

The choke line friction shall be included when calculating kick tolerances for SSWs. The MAASP shall be reduced with a value equal to the choke line friction.

4.3 Well design

4.3.1 General

Well design is a process with the objective of establishing, verifying and documenting the selected technical solution that fulfils the purpose of the well, complies with requirements and has an acceptable risk of failure (by means of risk analysis) throughout the defined life cycle of the well.

A well design process shall be carried out for

- construction of new wells,
- alteration, changes or modification to existing wells,
- changes in the well design basis or premises.

4.3.2 Design basis, premises and assumptions

The design basis, premises and assumptions shall be established.

The following items should be assessed and documented:

a) Current well status.
b) Purpose of well.
c) Temperature, pore pressure and formation strength prognosis, including uncertainties.
d) Design life requirements, including abandonment scenarios.
e) Geological depth prognosis with expected stratigraphy and lithology, including uncertainties.
f) Potential hazards that may cause loss of well integrity.
g) Description of formation fluids.
h) Well path listing, target requirements and proximity calculations to offset wells.
i) Summary of reference well data and experience feedback.
j) Personnel safety, working environment and marine environment shall be considered in relation to selection of fluid type-/cuttings handling and disposal.

4.3.3 Load case scenarios

Static and dynamic load case scenarios for critical equipment installed or used in the well shall be established. Load calculations shall be performed and compared with minimum acceptance criteria/design factors. Calculations performed and selection performance ratings for material and equipment can be based on deterministic or probabilistic models. All calculations shall be verified and documented.

4.3.4 Design factors

Minimum design factors or other equivalent acceptance criteria shall be pre-defined for

- burst loads,
- collapse loads,
- axial loads,
- tri-axial loads.

For probabilistic calculations of loads and ratings, the probability of failure should be less than $10^{-3,5}$.

4.4 Risk assessment and risk verification methods

See NORSOK Z-013.

Risk verification methods, such as safe job analysis, should be conducted on site for

- new or non-standard operations,
- operations involving use of new or modified equipment,
- hazardous operations,
- change in actual conditions which may increase the risk.

4.5 Simultaneous and critical activities

4.5.1 General

Simultaneous and critical activities and operations shall be thoroughly planned, analyzed and performed with the objective of limiting additional risk imposed by multiple activities and operations at the same time, as opposed to the risk associated with the execution of these individually.

Acceptance of simultaneous and critical activities and operations shall be in accordance with defined acceptance criteria and shall be quality assured through risk assessments.

Procedures for the control of simultaneous and critical activities and operations shall be developed and approved prior to commencement.

4.5.2 Simultaneous activities and operations

The following activities/operations are defined as simultaneous if two or more of these are executed at the same time within the defined area for such activity:

Simultaneous activity/Operation	Description
Coiled tubing	See Clause 11.
Completion	See Clause 7.
Conductor installation	Applies when the installation is defined as “hot”.
Construction	Major construction or modification work on an installation.
Drilling with BOP installed	See Clause 5.
Drilling with diverter installed	See Clause 5.
Drilling with no diverter or BOP installed	See Clause 5.
Injection or flowing from tubular annuli	See Clause 8.
Injection or flowing through temporary lines	See Clause 14.
Pipe line pigging	With potential for release of hydrocarbons.
Production or injection of hydrocarbons or water	See Clause 8 and Clause 6.
Moving of rig	skidding
Snubbing	See Clause 12.
Through tubing drilling and completion operations	See Clause 5 or Clause 7.
Under balanced drilling and completion	See Clause 13.
Wireline	See Clause 10.

4.5.3 Critical activities and operations

The following activities/operations are defined as critical:

Critical activity/operation	Description
Confined space entry	All entry into tanks, vessels and other spaces that normally are not accessible and which can have a potentially hazardous atmosphere.
Disconnection of safety system	Emergency shut-in or shut down systems, emergency blow-down or discharge systems, and emergency marine riser disconnect systems.
Lifting operations	Transfer of loads to and from supply vessel, lifts onboard the installation by use of cranes. Movement of tubulars, etc. on the pipe deck, and from the pipe deck to the drill floor and vice versa, cranes or dedicated pipe handling machines.
Hot work	
Repair or change-out of production tree or annulus valves	When these are WBEs in one of the two required well barriers.
Transfer and use of explosive material	Includes substances that can self-ignite.
Transfer and use of radioactive material	
Transfer of flammable liquids	Transfer of flammable liquids, like diesel or methanol, from supply vessel, or internally on the installation, through temporary piping or hose connections.

4.6 Activity and operation shut-down criteria

Criteria for shut-down of the activities or operations shall be established.

Activities and operations should cease, when

- having a weakened/impaired well barrier/WBE or failure/loss of a well barrier/WBE,
- high probability for exceeding allowable operating limits of well control equipment and other critical equipment,

- hydrocarbon gas level in air exceeds the specified limit, see NORSOK S-001,
- H_2S gas level in air exceeds a time weighted average of 10 x 10^{-6} or instantaneous reading of 20 x 10^{-6} for a period of maximum 10 min,
- H_2S content of fluids or gases exceeds operating limits of the well control equipment and other critical equipment.

4.7 Activity programmes and procedures

4.7.1 General

An activity programme shall be issued prior to commencement of

- drilling activities,
- formation testing activities,
- completion activities,
- well intervention operations,
- suspension and abandonment activities.

The main contractor(s) should be involved in the process of developing the activity program.

The programme may be supplemented by more detailed procedures relating to planning, execution and close-out of the activities.

Significant deviations from the programme shall be formally documented, approved and distributed to holders of the programme.

Programme and plans that have a validity period for more than one year should be regularly updated.

A new programme shall be prepared for wells that have not been put to use according to the original plan, or that have been temporarily suspended for more than three years.

4.7.2 Content of activity programmes

The activity programme should contain when applicable:

Item	Contents / Program for	Drilling	Formation Testing	Completion	Well Intervention	Sups. and Aband.
General:						
1.	Purpose of the activity, time and schedule.	x	x	x	x	x
2.	Name of installation/vessel, production license number, block number, field name.	x	x	x	x	x
3.	Well identification, classification.	x	x	x	x	x
4.	Position of well (geographical and universal transverse mercator coordinate systems), water depth.	x				
5.	Well status before and after the activity in the well, including: hole diameter, casing size, fluid, cementing heights, completion and test string schematics, plugs and any other equipment in the well.	x	x	x	x	x
6.	Plans for future use of temporally abandoned wells, including an assessment of the well integrity in relation to the expected lifetime of the well barriers, a description of protection of the wellhead, planned location inspections and frequency of these.					x
7.	Deviations from governmental and internal requirements.	x	x	x	x	x
Organization:						
8.	Organization plan.	x	x	x	x	x
9.	Responsibilities and communication during normal operations and emergency situations.	⊗	⊗	⊗	⊗	⊗
10.	List of contractors.	x	x	x	x	x
Geology and reservoir data:						
11.	Geological prognosis and information.	x				
12.	Pore/reservoir pressure prognosis and information.	x				x
13.	Plan for geological sampling and logging.	x				
14.	Reservoir data prognosis and information.	x	x	x	x	x
15.	Plan for reservoir technical sampling and logging.	x	x		x	
16.	Perforation intervals, production zones, flow shut-in periods.		x	x	x	x
17.	Estimated flow or injection rates, discharges, environmental consequences.		x		x	
18.	Plan for stimulation.		x	x	x	
Technical data:						
19.	Casing/tubing program and information.	x		x		x
20.	Cementing program and information.	x				x
21.	Fluids program and information, including an oil-based drilling safety assessment, if applicable.	x	x	x	x	x
22.	Planned /actual well profile and co-ordinates, including assessment of well bore collision risk.	x				x
23.	Operational constraints and shut-down criteria.	⊗	⊗	⊗	⊗	⊗
24.	References to operational procedures and instructions.	x	x	x	x	x
25.	Detailed overview of operational sequence.	x	x	x	x	x
26.	Detailed description of well barriers and well control equipment.	⊗	⊗	⊗	⊗	⊗
Safety:						
27.	Safety and operational hazards and planned risk reducing measures.	x	x	x	x	x
28.	Drills related to safety.	⊗	⊗	⊗	⊗	⊗

⊗ For production wells only, this information can alternatively be available in other documents.

4.8 Contingency plans

4.8.1 Installation blow-out contingency plan

A blow-out contingency plan shall be established for each installation, which shall contain an overview of

- strategy for killing the wells,
- requirements relating to position measurements of wellhead and well bore trajectory,
- necessary equipment, personnel, services,
- measures for limiting the consequences of a blow-out,
- guidelines for normalization of the operation.

4.8.2 Plan for drilling a relief well

An outline plan for drilling a relief well shall be developed for each well or well cluster location, which should contain

- identification of minimum two suitable locations for drilling a relief well, including shallow seismic interpretation of the top-hole section,
- assessment of methods for positioning the relief well close to the blowing well,
- identification of preferred kill method on the basis of estimated blow-out rates, including necessary pumping capacity,
- overview of equipment requirements to the installation/vessel performing the relief drilling and well killing,
- identification of time critical activities,
- overview of availability of well equipment and specialized equipment and services,
- overview of drilling rigs which can be used and possible mobilized,
- the chosen well killing strategy which shall be initiated as soon as possible. An alternate (back up) strategy should be implemented depending upon the probability of failure of the primary strategy.

Initiation of relief well drilling shall commence no later than 12 d after the decision to drill has been declared.

4.9 Personnel competence and supervision

4.9.1 Personnel competence

Reference is made to

- The Education Plan approved by the Norwegian Ministry of Church, Education and Research in respect of Well Service Techniques, Wireline Operations and Cementing,
- OLF/NR's, No.024. Recommendations for Training of Drilling and Well Service Personnel,
- NORSOK R-003N.

The formal requirements should be described in the job description for the position. Verification of the individual's competence can be done through gap analysis, tests or interviews. A scheduled training program, which may consist of courses, self-study program or on-the-job training, should be conducted to close gaps.

When new equipment will be used, involved personnel shall attend theoretical and practical proficiency training.

4.9.2 Supervision of operations

The offshore activities and operations shall be monitored and supervised by a competent person to ensure that procedures, programs and plans are followed in and safe and efficient manner.

Organization roles, responsibilities and authorities for critical personnel and position (s) that is (are) overall responsible for well integrity through the various phases/stages of the well, shall be defined and communicated to all involved personnel.

Critical information shall be effectively communicated and without delay to involved parties. Critical information can be communicated through reports after accidents and incidents, instructions following planned hot work and simultaneous activities.

4.10 Experience transfer and reporting

4.10.1 General

The results of and the experience from a particular activity or operation shall be systematically collected, documented and made available for future use.

This system can comprise

- drilling and well activities reporting system,
- accident and incident reporting system,
- non-conformity / deviations/change system,
- end of well/activity/operations reports,
- risk register for monitoring of risks,
- special reports.

4.10.2 End of activity report

A end of activity report shall be issued after completion of

- drilling activities,
- completion activities,
- well testing activities,
- well intervention operations.

The report should contain

- work objective and results,
- conclusions and recommendations,
- well status before and after completion of work,
- significant deviations from the original program, established operational procedures or regulations, including well incidents,
- summary of work performed,
- summary of investigation reports,
- cost breakdown and a comparison between planned and cost,
- time breakdown and analysis,
- well test or production results,
- analysis of other quality and performance parameters.

4.10.3 Well integrity information

Information relating to well integrity shall be documented.

The following records should be retained:

Item	Description	Retention period	Comments
1.	Equipment specifications and material certificates of technical components well barriers/WBEs.	For the period that it is in use.	Dimensional size and type of material for wellhead, casing, liner, tubing, packers, etc.
2.	Directional survey and wellhead coordinates.	Unlimited	
3.	Pressure test and leak test records and other records relating to acceptance of technical well barriers or WBEs.	For the period that it is in use.	Can be used for statistical purposes.
4.	Well handover document.	Until the well has been permanently abandoned.	This should describe the well barrier status before the responsibility for well integrity is transferred to another organizational unit.
5.	Drills conducted and results.	1 year	Can be used for statistical purposes.

4.10.4 Special well incident reporting

The Petroleum Safety Authority (PSA) shall be notified immediately in the event of shallow-gas is detected and in the event of well influx/inflow (kick) where the following steps have occurred:

a) Positive indication of flow from wellbore.
b) The wellbore is closed by shutting in the BOP/safety valve.
c) Pressure or pressure build up is registered in the closed-in wellbore.
d) Kill operation is initiated, which can be
   1) bull heading;
   2) driller's method or weight and weight method;
   3) volumetric method.

Additional information shall be reported by completing the relevant sections in SPA’s Common Data Reporting system.

5 Drilling activities

5.1 General

This clause covers requirements and guidelines pertaining to well integrity during drilling activities and operations including through tubing drilling.

The activity starts with spudding of the well and concludes with preparation for completion or testing activities or well for sidetracking, suspension or abandonment.

The purpose of this clause is to describe the establishment of well barriers by use of WBEs and additional features required to execute this activity in a safe manner.

5.2 Well barrier schematics

It is recommended that WBSs are developed as a practical method to demonstrate and illustrate the presence of the defined primary and secondary well barriers in the well, see 4.2.
In the table below some typical scenarios are listed including references to attached illustrations.
The table is not comprehensive and schematics for the actual situations during an activity or operation should be made.

Item	Description	Comments	See
1.	Drilling, coring and tripping with shearable drill string.		5.8.1
2.	Running non-shearable drill string.		5.8.2
3.	Running non-shearable casing.		5.8.3
4.	Through tubing drilling and coring.		5.8.4
5.	Pipe conveyed wireline logging.		10.8.5

5.3 Well barrier acceptance criteria

The following requirements and guidelines apply:

a) Drilling of top hole can be conducted with the fluid column as the only well barrier. Potential shallow gas zones should not be penetrated.
b) Prior to drilling out of the surface casing, a drilling BOP shall be installed.
c) Prior to drilling the lateral bore in a multi-lateral well, well control action procedures shall be established for controlling influxes from any of the previously drilled bores.
d) Floating (partially filled up) of non-shearable tubular strings in open hole or with open perforations exposed should be conducted with two qualified WBEs located inside the tubular. The inside WBEs shall be designed such that fluid can be circulated.
e) Prior to initiating an operation, an assessment of risks associated with the intended operation shall be made.

5.4 Well barrier elements acceptance criteria

5.4.1 General

Subclause 5.8 lists the WBEs that constitute the primary and secondary well barriers for situations that are illustrated.

5.4.2 Additional well barrier elements (WBEs) acceptance criteria

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

<table>
<tr><th>No.</th><th>Element name</th><th>Additional features, requirements and guidelines</th></tr>
<tr><td>Table 1</td><td>Fluid column</td><td>Riser margin (only applicable for vessels with a marine riser)

The fluid column is not a qualified well barrier when the marine riser has been disconnected. Planned or accidental disconnect of the marine riser, resulting in loss of the fluid well barrier shall be planned for. Procedures for planning and implementation of compensating measures shall be established.

If the uncased borehole has penetrated hydrocarbon bearing formations or abnormally pressured formations with a flow potential and the hydrostatic pressure in the well with the riser disconnected may become less than or equal to the pore/reservoir pressure of these formations, risk reducing measures shall be established with the following priority :

A. reduce the probability of having an influx during the disconnect period
B. strengthen the availability/reliability of the remaining well barrier.

The following table is listing some examples of risk reducing measures that could be applied.

<table>
<tr><th>Priority</th><th>Risk reducing measures</th><th>Comments</th></tr>
<tr><td>A</td><td>Drill with “Riser Margin”</td><td>Maintain a drilling fluid density that will provide an overbalance with the marine riser disconnected.
This alternative shall be assessed as the primary compensating measure.</td></tr>
<tr><td>A</td><td>Spot a weighted fluid</td><td>Displace the entire well or part of the well to a fluid with a density that will provide an overbalance towards zones with a flow potential with the marine riser disconnected.</td></tr>
<tr><td>B</td><td>Install a bridge plug</td><td>Install a bridge plug with storm valve below the wellhead.</td></tr>
<tr><td>B</td><td>Two shear-/seal rams</td><td>Use two shear-/seal rams in the drilling BOP as an extra seal element during hang-off / drive-off situations.</td></tr>
<tr><td></td><td></td><td></td></tr>
</table>
</td></tr>
</table>

5.4.3 Common well barrier elements (WBEs)

There are no identified common WBEs in 5.2.

5.5 Well control action procedures and drills

5.5.1 Well control action procedures

The following table describes incident scenarios for which well control action procedures should be available (if applicable) to deal with the incidents should they occur. This list is not comprehensive and additional scenarios may be applied based on the actual planned activity, see 4.2.7.

Item	Description	Comments
1.	Shallow gas influx.	
2.	Influx occurring with shearable pipe or tools through the BOP.	
3.	Influx occurring with non-shearable pipe or tools through the BOP.	
4.	Influx containing H_2S.	

5.5.2 Well control action drills

The following well control action drills should be performed:

Type	Frequency	Objective	Comments
Shallow gas kick drill - Drilling	Once per well with crew on tour.	Response training to an shallow gas influx.	To be done prior to drilling surface hole or pilot hole .
Kick drill - Drilling	Once per week per crew.	Response training to an influx while drilling (bit on bottom).	
Kick drill - Tripping	Once per week per crew.	Response training to an influx while tripping (bit off bottom).	
Choke drill	Once per well with crew on tour.	Practice in operating the power choke with pressure in the well.	Before drilling out of the last casing set above a prospective reservoir.
H_2S drill	Prior to drilling into a potential H_2S zone/reservoir.	Practice in use of respiratory equipment.	

5.6 Casing design

5.6.1 General

All components of the casing string including connections, circulation devices and landing string shall be subject to load case verification.

The weakest points in the string with regards to burst, collapse and tensile strength rating shall be clearly identified.

For through tubing drilling operations, the tubing and accessories shall be reclassified to casing and be redesigned to meet drilling loads.

5.6.2 Design basis, premises and assumptions

The following data should be used to establish the dimensioning parameters for the design process. Experience from previous wells in the area or similar wells shall be assessed.

a) Planned well trajectory and bending stresses induced by doglegs and hole curvature.
b) Maximum allowable setting depth with regards to kick margin.
c) Estimated pore pressure development.
d) Estimated formation strength.
e) Estimated temperature gradient.
f) Drilling fluids and cement program.
g) Loads induced by well services and operations.
h) Completion design requirements.
i) Estimated casing wear.
j) Setting depth restrictions due to formation evaluation requirements.
k) Potential for H_2S and/or CO_2.
l) Metallurgical considerations.

m) Well abandonment requirements.
n) ECD and surge/swab effects due to narrow annulus clearances.
o) Isolation of weak formation, potential loss zones, sloughing and caving formations and protection of reservoirs.
p) Geo-tectonic forces if applicable.
q) Any other requirements that may influence casing string loads or service life.

5.6.3 Load cases

When designing for burst, collapse and axial loads, the following load cases shall minimum be considered. This list is not comprehensive and load cases applicable for the planned activity shall be applied. Possible changes in design loads and stresses during the life expectancy of the well shall be assessed.

Item	Description	Comments
1.	Gas kick.	Size/volume and intensity to be defined.
2.	Gas filled casing (floating installations).	Applicable to last casing above the reservoir and subsequent casings.
3.	Production and/or Injection tubing leaks.	Based on METP. See 7.7.2 for multipurpose wells.
4.	Cementing of casing.	
5.	Leak testing casing.	See 7.7.2 for multipurpose wells.
6.	Thermal expansion of fluid in enclosed annuli.	Collapse and burst.
7.	Dynamic loads from running of casing, including over pull to free stuck casing.	

5.6.4 Minimum design factors

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

Burst	1,1
Collapse	1,0
Tension	1,3
Tri-axial	1,25

As an alternative to the above design factors, stress design or stress verification programs might be employed to demonstrate the presence of appropriate design factor(s). Minimum design factors (for burst, collapse and axial loads) = load induced stress/capacity.

For probabilistic calculations of loads and ratings, the probability of failure should be less than $10^{-3,5}$.

5.7 Other topics

5.7.1 Drilling location

A site survey shall be performed and interpreted to identify water depth, seabed and sub-surface hazards at the intended well location and relief well locations. The survey can be performed with means of sonar equipment and direct visual observations. Sea bed topography, anchor holding capabilities, presence of boulders, cables, pipelines and other obstructions should be assessed.

Well locations shall be selected where the risk associated with shallow gas is acceptable.

The seismic lines shall have a penetration covering the geological sequence to the setting depth for the surface casing.

Soil tests should be available for intended deep water and jack-up drilling locations.

5.7.2 Shallow gas

5.7.2.1 General

This risk for drilling into shallow gas shall be assessed for all wells together with risk reducing measures.

The risk assessment shall be based on

- interpretation of data from relevant offset wells, and
- interpretation of the shallow seismic survey at the indented well location.

The following shall be established:

a) A model/procedure for defining the risk of shallow gas and operational constraints.
b) Criteria for drilling a pilot hole and when to drill with riser/diverter installed.
c) Operational procedures and well control action procedures for drilling through potential shallow gas zones with focus on risk reducing measures.
d) Selection of alternate locations.

5.7.2.2 Shallow gas risk assessment model

The following should be evaluated to determine the probability of shallow gas:

a) Whether shallow gas is detected in relevant offset wells and in the same formations that will be penetrated in the well.
b) Whether a structural closure is seen on the seismic that could trap shallow gas.
c) Whether there are anomalies on the seismic interpretation that could indicate presence of gas.

If the answer to minimum one of the criteria above is yes, the well shall be classified as a potential shallow gas well.

The consequence of drilling through shallow gas zones should be evaluated concerning drilling

- with semi submersible/drill ship or jack-up/platform,
- water depth less or more than 100 m,
- drilling with or without riser,
- wind and current conditions while drilling.

5.7.2.3 Operational constraints

The following operational constraints are applicable for a potential shallow gas well:

a) The well location shall if possible be moved if consequence and/or probability of shallow gas is high.
b) A pilot hole shall be drilled through all potential shallow gas zones.
c) Predicted shallow gas abnormal pressured zones shall be drilled with weighted drilling fluid.
d) It shall be possible to kill the pilot hole dynamically
e) A float valve without an orifice shall be installed in the BHA.
f) The potential shallow zones should be logged with LWD gamma ray resistivity.
g) Returns from the borehole shall be observed with ROV camera or remote camera.
h) Kill fluid shall be available until the pilot hole has been opened.
i) Cementing materials shall be onboard to set a 50 m long gas tight cement plug in the pilot hole with 200 % excess.
j) Plans and materials for setting surface casing above a shallow gas zone should be prepared.

The following operational constraints shall be observed for shallow water:

If no pilot hole is planned for water depth less than 100 m, regardless of how remote the probability of encountering shallow gas might be, a drilling facility impact assessment shall be performed with respect to shallow gas influx.

5.7.3 Pore pressure estimation

Estimation of pore pressure shall commence after drilling out of the surface casing and should be estimated regularly when new formation is drilled.

The methods and techniques for estimating the pore pressure shall be described.

5.7.4 Well trajectory measurements and anti-collision monitoring

5.7.4.1 General

Precise determination of the well path is important to

- avoid penetrating another well,
- facilitate intersection of the well bore with a relief well (blow-out),
- facilitate geological modeling.

5.7.4.2 Well trajectory measurements

The following apply:

a) The surface location coordinates of the well bore centre shall be determined with use of differential global positioning system. Well slot co-ordinates can be established by measurements from a known reference point (fixed point on a platform, sub sea template, etc.).
b) During drilling of new formation, measurement of well bore inclination and direction shall be obtained at least every 100 m MD. All survey plots should be referenced to grid north.
c) The position of the well bore being drilled (reference well) and the distance to adjacent wells (object well) shall be known at all times. The minimum curvature method or other equivalent models should be used.
d) A model for quantifying the uncertainty shall be established. The probability for the well bore to be within the calculated uncertainty ellipses should exceed 95 %.
e) Minimum acceptable separation distance between well bores and risk reducing actions shall be defined.

5.7.4.3 Model and acceptance criteria for separation between well bores

The following model can be used to define minimum acceptable separation:

SF = D / (Er + Eo + Rr + Ro)

where:

SF= separation factor
Er = ellipse radius of reference well (well being drilled) in the direction of the object well
Eo = ellipse radius of the object well (neighbouring well) in the direction of the reference well
Rr = bit radius of reference well
Ro= casing radius in the object well
D = computed distance between the centre of reference well and centre of the object well.

The table below describes recommended actions to be taken for SF < 1,0.

Point of potential contact	Recommended action
Casing with no well barrier function.	The cuttings from the reference well should be analyzed to determine cement and/or metal content prior to exceeding the SF (base line) and when drilling within this range. The casing by casing annuli in object well(s) with access to the point of potential contact should be pressurised and monitored for changes in pressure in case there is penetration by the drill bit. If this is not possible, alternative methods such as noise detection should be used.
Casing with a function as secondary well barrier or production liner.	As above, and: The production/injection of the object well(s) should cease, and the object well(s) should be secured by closing of the SCSSV/ASCSSV, or setting tubing plugs, bridge plugs, or cement plugs. Installation of a well barrier below the estimated point of contact shall be assessed.

5.7.5 Through tubing drilling activities

Through tubing drilling activities shall be regarded as alterations to existing well and hence new design basis shall be established. A new well design process shall be carried out on the revised design basis/premises, see 4.3 and 5.6.

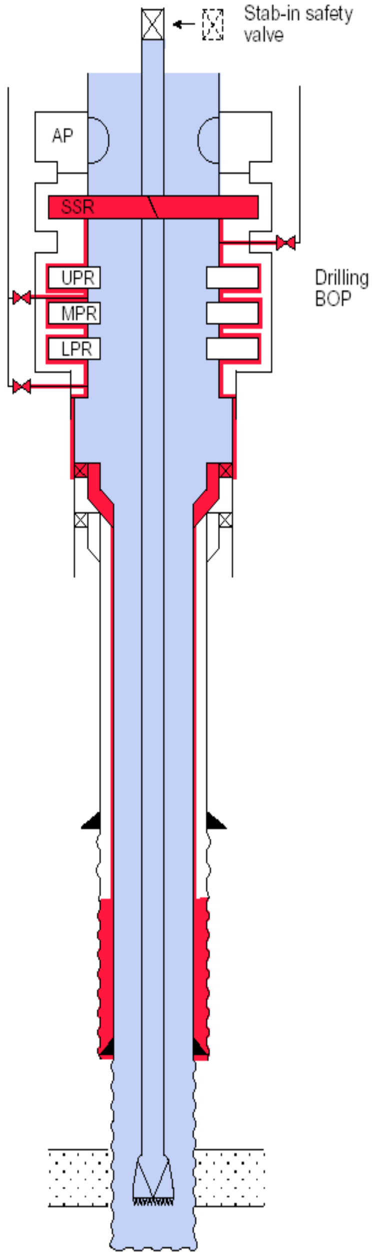
All primary and secondary WBEs shall be verified to meet the new design loads prior to commencing operation.

Special considerations shall be put on protection of elements not normally exposed to drilling loads (production tree, tubing, SCSSV etc.). These elements should either be protected against the loads (i.e. by installing wear sleeve/bushing in SCSSV and /or production tree) or be verified capable of resisting the defined loads. Calculations documenting acceptance of the new loads and/or mitigations to reduce/eliminate loads should be verified by supplier and if critical by independent expert.

If through tubing drilling is performed in UB/CT/snubbing mode, the relevant sections of this NORSOK standard describing these operations shall be adhered to, see Clause 11, Clause 12 and Clause 13.

5.8 Well barrier schematic illustrations

5.8.1 Drilling, coring and tripping with shearable drill string

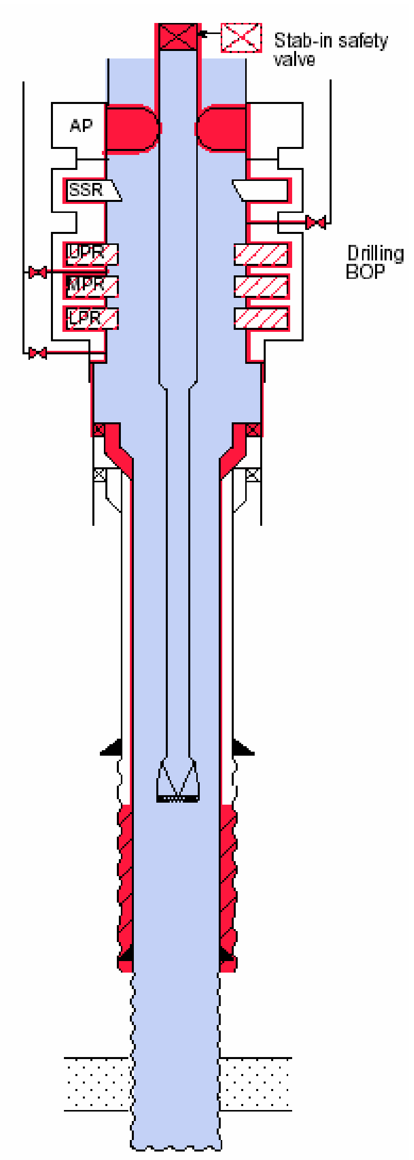


Well barrier elements	See Table	Comments
Primary well barrier		
1. Fluid column	1	
Secondary well barrier		
1. Casing cement	22	
2. Casing	2	Last casing set.
3. Wellhead	5	
4. High pressure riser	26	If installed.
5. Drilling BOP	4	

Note

None

5.8.2 Running non-shearable drill string

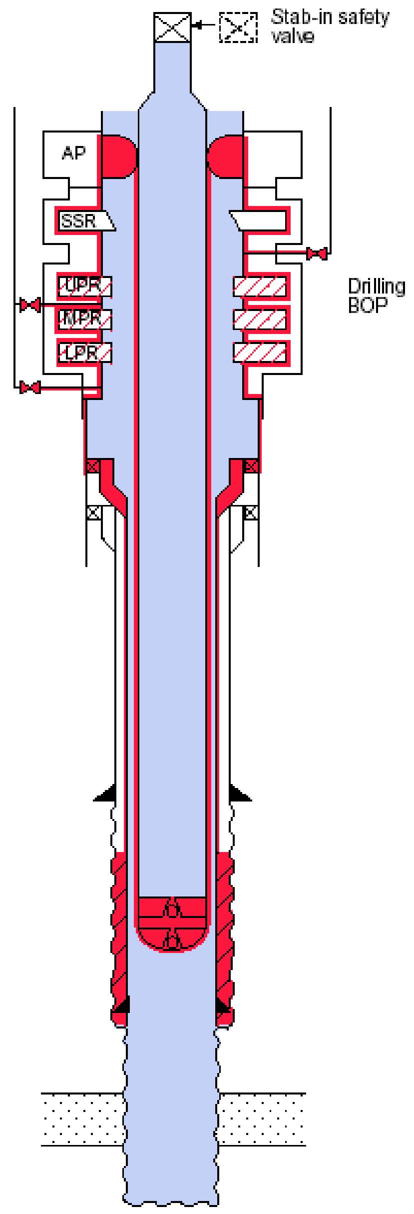


Well barrier elements	See Table	Comments
Primary well barrier		
1. Fluid column	1	.
Secondary well barrier		
1. Casing cement	22	
2. Casing	2	Last casing set.
3. Wellhead	5	
4. High pressure riser	26	If installed.
5. Drilling BOP	4	
6. Drill string	3	Drill collars and BHA.
7. Stab-in safety valve	40	

Note

None

5.8.3 Running non-shearable casing

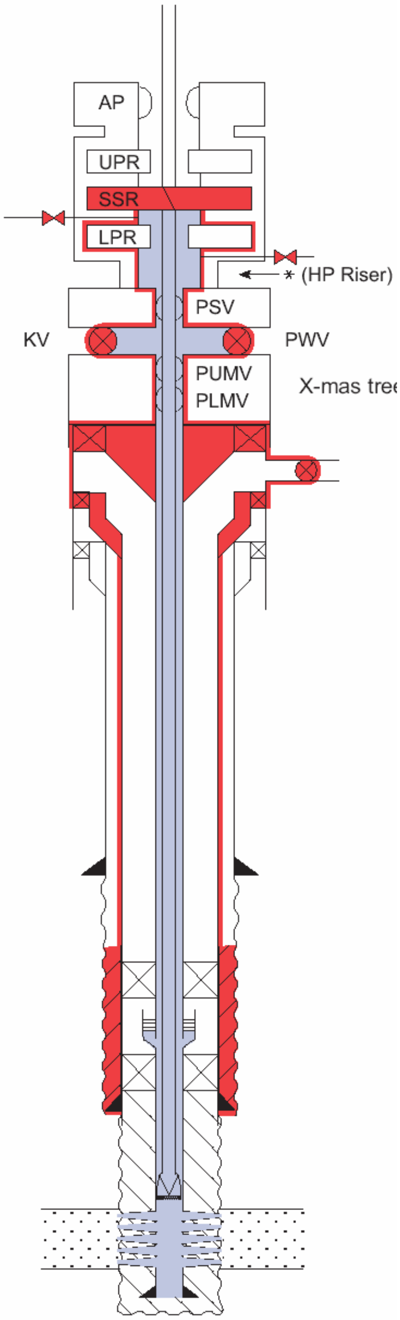


Well barrier elements	See Table	Comments
Primary well barrier		
1. Fluid column	1	
Secondary well barrier		
1. Casing cement	22	
2. Casing	2	Last casing set.
3. Wellhead	5	
4. High pressure riser	26	If installed.
5. Drilling BOP	4	
6. Casing	2	See NOTE
7. Casing float valves	41	

Note
The criteria for accepting casing as WBE during running of casing without prior leak testing of each connection are:

1. Pipe body and connections are designed to withstand defined loads.
2. Casing is manufactured according to accepted standards.
3. Connections are inspected and made-up according to established procedures.
4. Stab-in safety valve is readily available on the drill floor.

5.8.4 Through tubing drilling and coring



Well barrier elements	See	Additional features, requirements and guidelines
Primary barrier		
1. Fluid column	Table 1	
Secondary barrier		
1. Casing	Table 2	
2. Casing cement	Table 22	
3. Wellhead	Table 5	
4. Tubing hanger	Table 10	
5. Production tree	Table 31 Table 33	
6. High pressure riser	Table 26	Between surface production tree and drilling BOP
7. Drilling BOP	Table 4	Shear-seal rams
8. Annulus access line and valve	Table 12	

NOTE

1. None

6 Well testing activities

6.1 General

This section covers requirements and guidelines pertaining to well integrity during well testing. The well testing activity typically starts after having drilled the last open hole section and the liner is ready to be set. 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 WBEs and additional features required to execute this activity in a safe manner.

6.2 Well barrier schematics

It is recommended that WBSs are developed as a practical method to demonstrate and illustrate the presence of the defined primary and secondary barriers in the well, see 4.2. In the table below there are a number of typical scenarios listed, all listed items are attached as illustrations. The table is not comprehensive and schematics for the actual situations during an activity or operation should be made.

Item	Description	Comments	See
1.	Running closed end well test string	None	6.8.1
2.	Testing - Flowing and shut-in periods	None	6.8.2
3.	Well testing – Landing string disconnected	None	6.8.3
4.	R/U and R/D WL equipment and changing WL during well testing	None	6.8.4

6.3 Well barrier acceptance criteria

The following requirements apply:

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 at BOP level in a controlled manner.
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 through the STT and hooked and surface lines using the fluid pump or high pressure (cement) pump, with returns through the rig’s choke manifold and fluid or gas separator.
d) The trip tank level shall be monitored regularly.
e) It shall be possible to circulate the test string during running in, anytime during testing and while pulling out.

6.4 Well barrier elements acceptance criteria

6.4.1 General

Subclause 6.8 of this section lists the WBEs that constitute the primary and secondary barriers for situations that are illustrated.

6.4.2 Additional well barrier elements (WBEs) acceptance criteria

The following table describes features, requirements and guidelines that are additional to what is described in Clause 15.

No.	Element name	Additional features, requirements and guidelines
Table 22	Casing cement	When setting the well test packer inside a liner it shall be verified by actual leak testing that the casing and linerlap has sufficient pressure retaining capacity to withstand the maximum differential pressure exercised by the fluid column and a leaking tubing scenario.
Table 43	Liner top packer	
Table 4	Drilling BOP	The BOP stack shall have sufficient height allowing the SSTT (or safety valve for jack-ups) to be positioned by closure of one pipe ram around the slick joint while still having the ability to close the shear/seal ram above the SSTT valve in a connected configuration (with latch attached to valve). HPHT: Elastomers in the BOP stack shall have a documented ability to withstand the maximum expected temperature.
Table 2	Fluid column	During well testing operations where dedicated wellbore fluid is being used there shall be sufficient fluid available on the installation to cater for any situation that might develop. Typically this will require minimum additional 100 % well volume of the same or alternative fluid to control the well.

6.4.3 Common well barrier elements (WBEs)

There are no identified common WBEs in 6.2.

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 (if applicable) to deal with the incidents should they occur. This list is not comprehensive and additional scenarios may be applied based on the actual planned activity, see 4.2.7.

Item	Description	Comments
1.	Inflow or fluid loss while running or pulling test string.	At all times when running or pulling tubing or completion BHA, a stab-in (tubing) safety valve made up on the actual x-over(s) to the string shall be prepared and made ready for use immediately in case of flow.
2.	Tubing leak.	
3.	Disconnect of SSTT for SSWs.	Criteria for heave limit should be described. Disconnect drill. Loss of position (drift/drive off).
4.	Presence of solids/sand.	Criteria for when reduce or cease flowing should be established.
5.	Presence of H_2S in the well stream.	Criteria for when to implement contingency measures or abort the test should be established.
6.	Hydrates	Contingency measures can be • supply heat to affected area if possible, • inject suitable hydrate inhibitor (i.e. glycol/methanol), • continue to flow well ?, • shut in down hole to exit the hydrate forming envelope.
7.	Wax	Contingency measures can be • supply heat to affected area if possible, • inject wax breaking chemicals, • continue to flow well ?

Item	Description	Comments
8.	Emulsions	Contingency measures can be • supply heat to affected area if possible, • inject demulsifier, • continue to flow well ?
9.	Killing the well	Contingency killing during testing operations. See: Disconnecting the SSTT
10.	Stuck string	Maximum allowable overpull.

Tool pusher/driller and drill stem test operator/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:

Type	Frequency	Objective	Comments
Disconnect of the SSTT.	Once per shift as soon as practical after rig-up.	Response training.	Without physically disconnecting the SSTT (going through all the motions required on the rig floor and in the drillers cabin).
Major leak in STT swivel or flexible flowline(s).	Once per shift as soon as practical after rig-up.	Response training.	

6.6 Well test design

6.6.1 General

The selection of well testing operational methods and procedures and of well testing 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, well barriers and optimal solutions for the specific well based on the well design.

6.6.2 Design basis, premises and assumptions

See NORSOK D-SR-007.

All components of the test string (tubing, gauge carriers, slip joints, safety joints, drill collar, valves, nipples, etc.) shall be subject to load case verification.

Test string design calculations should be documented by recognized methods, e.g. recognized computer programs. Axial and triaxial loads shall be calculated and checked against tubing strength. The weakest point in the test string shall be clearly identified with regards to burst, collapse and tensile strength rating.

METP shall be determined for each individual case and shall be calculated based on

- maximum expected fracture pressure,
- maximum pressure to fire TCP guns,
- maximum expected kill pressure (shut-in wellhead pressure + 7 MPa).

For thermal tubing the stress loads should be calculated using the inner pipe for stress check purposes disregarding the outer pipe.

6.6.3 Load cases

When designing for burst, collapse and axial load, the following load cases shall minimum be considered. This list is not comprehensive and actual cases based on the planned activity shall be performed:

Item	Description	Comments
1.	Collapse at depth of lowest tool subject to annulus and wellhead pressure when test string is gas filled or when running the string without filling the string with fluid or cushion. This also applies to the liner below packer if the string gets evacuated.	Apply gas gradient pressure with weight of string below wellhead for the tubing side and hydrostatic column plus maximum applied surface pressure for the annulus side (normally required to shear rupture disc in circulating valve).
2.	Burst at surface and wellhead when pressure testing string prior to perforating.	Apply maximum expected test or bullheading pressure with weight of string below wellhead for the tubing side and zero pressure on the annulus side.
3.	Pulling load at surface when attempting to retrieve a stuck test string.	Apply necessary overpull for parting string at weak point plus 20 % with string weight not corrected for buoyancy.
4.	Tubing movement.	Leak testing, production, shut-in and killing with cold fluid conditions. Apply maximum expected bullheading pressure at cold temperature on the tubing side with zero annulus pressure.

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 (see Note)
d) Tri-axial yield: 1,25 Pipe body and connection whichever combination is weaker.

Note - The axial load factor should be set at 1,50 expected pulling load to cater for loads that might be experienced while pulling the packer free after the test.

Stress design or stress verification programs might be used to demonstrate the presence of appropriate design factor(s).

For probabilistic calculations of loads and ratings, the probability of failure should be less than $10^{-3,5}$.

6.6.5 Well test string equipment

The following items should as a minimum be considered included in the test string:

a) Retrievable test packer.
b) Two independent circulating valves.
c) Safety joint.

Insulated thermal tubing should be used in the landing string if the risk of hydrate and wax formation is considered to be high, e.g. deep water and wet gas.

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/or manual actions and contingency procedures for relevant scenarios and incidents.

6.7.2 Hydrate prevention

Chemical injection shall be available at critical points in the test string. Actions for combating hydrates once formed should be planned for. Injection of hydrate inhibitor and/or chemicals should start prior to opening/closing any sub surface valves and last as long as deemed necessary.

If hydrate risk is present, the production annulus fluid should be considered to include hydrate inhibitor in the case of a tubing leak.

6.7.3 HPHT well testing

The flowing wellhead temperature should never exceed the temperature limit of the equipment used.

6.7.4 Underbalanced well testing

An inflow test of the production liner lap (if installed) shall be done with a minimum hydrostatic column of seawater for wells that have seawater as the packer fluid and when the production packer is set in the liner.

For wells that have seawater as the packer fluid, the production casing shall be leak tested to maximum expected pressure actually using seawater as the packer fluid.

Kill fluid shall be readily available in tanks for displacement of the entire well volume.

6.7.5 Deep water well testing

When testing from a DP positioned vessel, procedures and plans pertaining to disconnect of the drilling riser shall be reviewed by all involved parties.

The flowing tubing temperature profile from seabed to rigfloor should be modeled as a function of variable flowrates and actual seabed temperatures and riser and landing string configuration.

The SSTT temperature should be monitored during testing.

The fluid/brine recipe needs to be prepared to cater for both the expected highest and lowest temperature performance, which could favor the use of brine.

6.7.6 Offshore pretest meeting

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

a) Number of zones to be tested.
b) Expected pressure, temperature and flowrates.
c) Expected duration of test operations.
d) Contingency reactions.
e) Risk analysis results.
f) PSD/ESD levels.
g) Plan over each service company's responsibility.
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) Localization of manual PSD buttons.
k) Localization of fire fighting equipment.
l) Pollution and oil spill restrictions and actions.

6.7.7 Disconnecting the subsea test tree (SSTT)

If the test string needs to be disconnected and the test stopped temporarily, one of the following methods should be applied:

a) Open the reverse circulating valve and circulate kill fluid into the string.
b) If the above is not possible, then bullhead the string content into the formation.
c) If neither of the above is not possible, the downhole tester valve and SSTT may be closed and inflow tested before the disconnect procedure can proceed.

6.7.8 Surface flow lines and connections

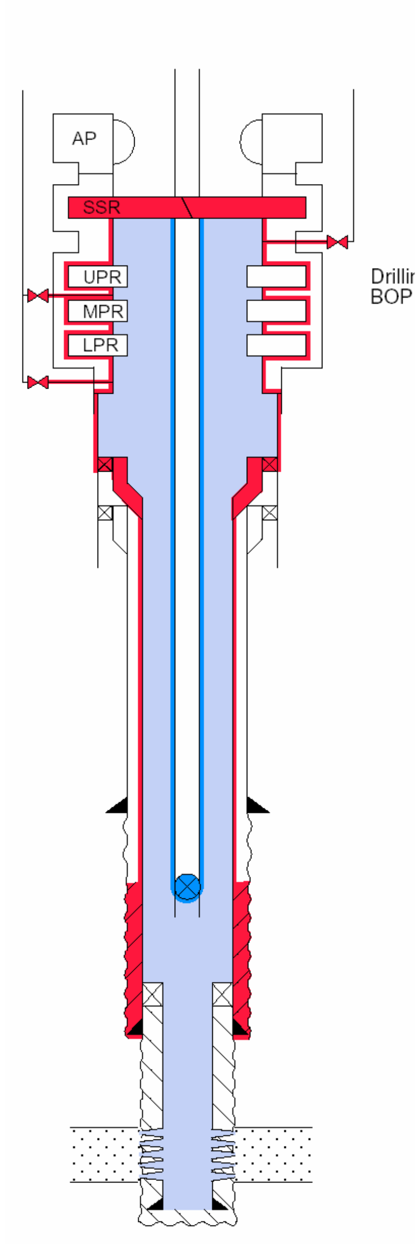
Chicksans and hammer union connections shall not be used upstream of the choke manifold.

All temporary flow lines shall be adequately anchored to prevent whipping, bouncing, or excess vibration, and to constrain all piping if a break should occur.

The cement unit and one fluid pump should be lined up to the kill side of the STT at all times during the well test phase.

6.8 Well barrier schematic illustrations

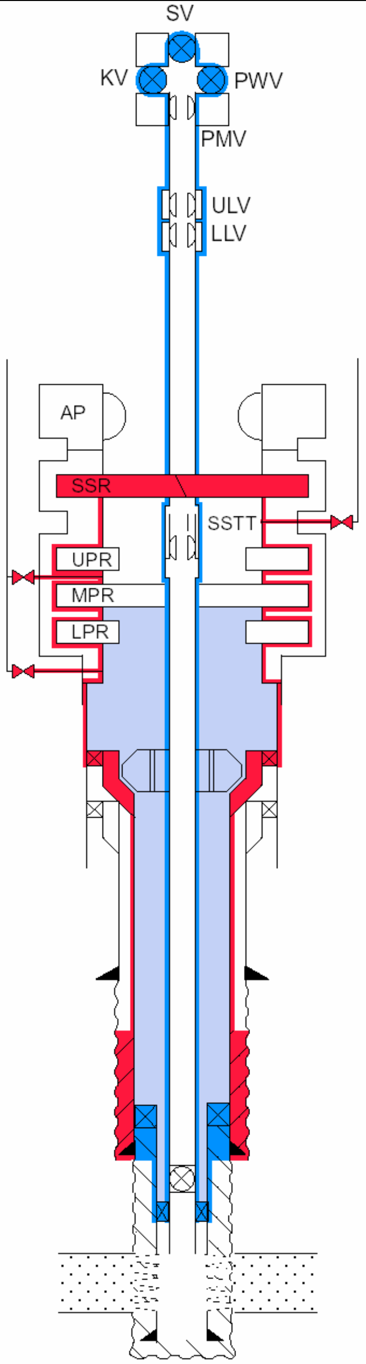
6.8.1 Running closed end well test string



Well barrier elements	See Table	Comments
Primary well barrier		
1. Fluid column	1	
2. Downhole tester valve	46	
3. Well test string	27	
Secondary well barrier		
1. Casing cement	22	
2. Casing	2	
3. Wellhead	5	Including casing hanger w/seals.
4. Drilling BOP	4	Body, choke and kill valves and shear seal ram.

Note
None

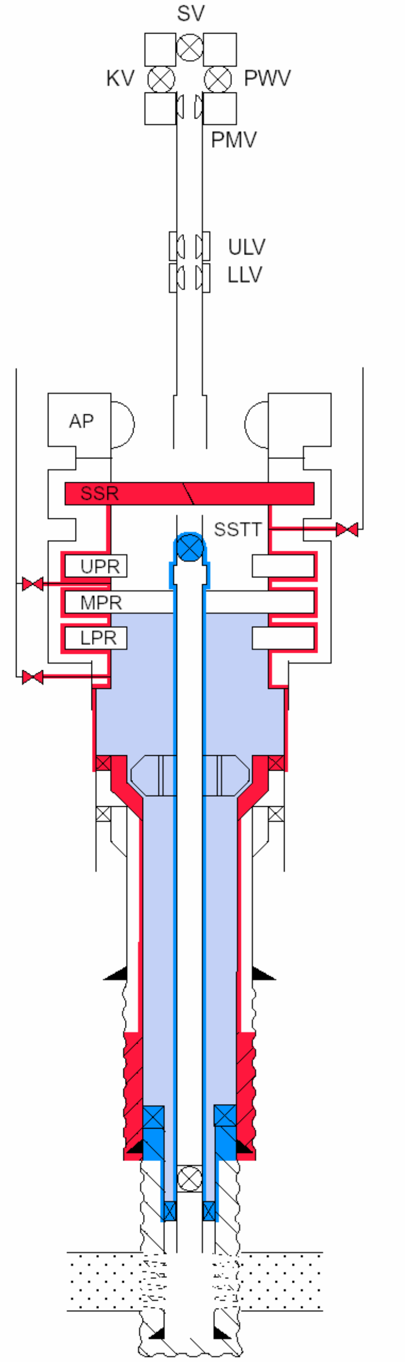
6.8.2 Testing - flowing and shut-in periods



Well barrier elements	See Table	Comments
Primary well barrier		
1. Liner top packer	43	
2. Casing (production liner)	2	
3. Well test packer and fluid column	35 1	Acting as a well barrier in combination
4. Downhole tester valve	46	Body only.
5. Well test string	25	
6. Subsea test tree	32	
7. Well test string	25	
8. Subsea lubricator valve	45	Body of subsea lubricator valve.
9. Surface test tree	34	Body of STT w/swab, kill and PWVs.
Secondary well barrier		
1. Casing cement	22	
2. Casing	2	
3. Wellhead	5	Including casing hanger w/seals.
4. Drilling BOP	4	Body, choke and kill valves and shear seal ram. Disconnect SSTT prior to closing shear ram.

Note
None

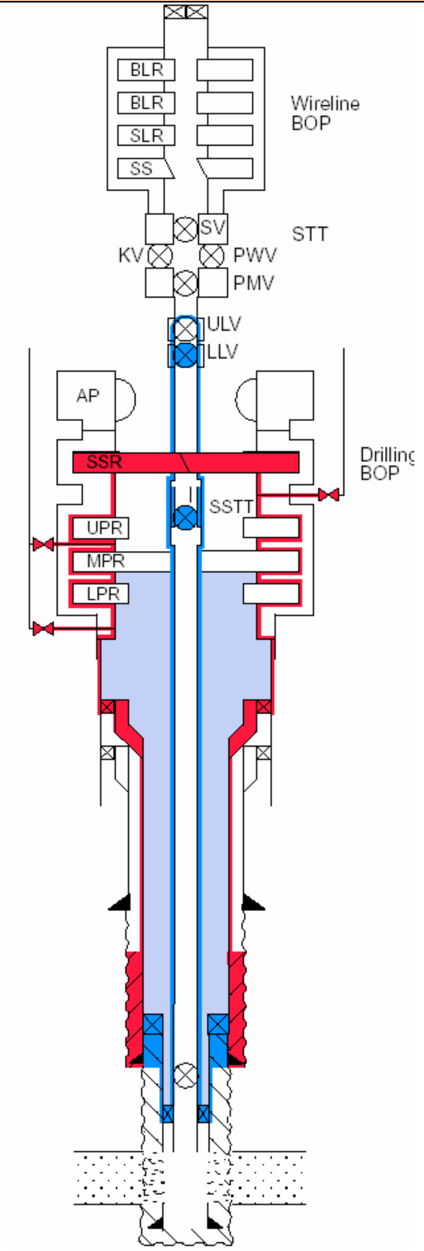
6.8.3 Well testing – landing string disconnected



Well barrier elements	See Table	Comments
Primary well barrier		
1. Liner top packer	43	
2. Casing	2	Production liner
3. Well test packer and fluid column	7 1	Acting as a well barrier in combination
4. Downhole tester valve	46	Body
5. Well test string	25	
6. Subsea test tree	32	Body and valve
Secondary well barrier		
1. Casing cement	22	
2. Casing	2	
3. Wellhead	5	Including casing hanger w/seals
4. Drilling BOP	4	Body, choke and kill valves and shear seal ram. Disconnect SSTT prior to closing shear ram

Note
None

6.8.4 R/U and R/D WL equipment and changing WL during well testing



Well barrier elements	See Table	Comments
Primary well barrier		
1. Liner top packer	43	
2. Casing (production liner)	2	
3. Well test packer and fluid column	7 2	Acting as a well barrier in combination
4. Downhole tester valve	46	Body
5. Well test string	25	From well test packer up to the SSTT.
6. Subsea test tree	32	Body
7. Well test string	25	Between SSTT and lubricator valve
8. Subsea lubricator valve	45	
9. STT	34	Closed PMV and/or safety valve to provide additional availability of primary well barrier.
Secondary well barrier		
1. Casing cement	22	
2. Casing	2	
3. Wellhead	5	Including casing hanger w/seals.
4. Drilling BOP	4	Body, choke and kill valves and shear seal ram. Disconnect SSTT prior to closing shear ram.

Note
None

7 Completion activities

7.1 General

This clause covers requirements pertaining to activities and operations for installation of tubular and equipment in the well that will be used for transport of media to and from the reservoir and surface. The completion activity typically starts after having drilled the well to total depth and starting with cleaning of the well and installation of completion equipment. The activity concludes with the suspension of the tubing hanger in the subsea wellhead or upon completion of the installation of the surface production tree.

The purpose of this clause is to describe the establishment of well barriers by use of WBEs and additional features required to execute the activity in a safe manner.

7.2 Well barrier schematics

It is recommended that WBSs are developed as a practical method to demonstrate and illustrate the presence of the defined primary and secondary barriers in the well, see 4.2. In the table below there are a number of typical scenarios listed, some of which are also attached as illustrations. The table is not comprehensive and schematics for the actual situations during an activity or operation should be made.

Item	Description	Comments	See
1.	Running and pulling of TCP guns.	None	
2.	Running open end completion string.	None	7.8.1
3.	Running closed end completion string.	None	
4.	Working in well with deep set tubing plug.	None	
5.	Running or pulling non shearable items through BOP.	None	7.8.2
6.	Pulling BOP and landing subsea production tree.	None	7.8.3
7.	Removal of BOP and installing surface production tree.	None	

7.3 Well barrier acceptance criteria

The following requirements apply:

a) Wells that are producing or are capable of producing hydrocarbons, shall have a mechanical annular seal between the completion string and the casing/liner, i.e. production packer.
b) A SCSSV shall be installed in the completion string for all hydrocarbon wells and wells with sufficient reservoir pressure to lift fluids to seabed level (including supercharged injection formations).
c) An ASCSSV should be installed in the completion string for all wells
   1) with a potential of hydrocarbon flow in the annulus, i.e. perforations above the production packer and injection into the annulus which might temporarily supercharge a formation;
   2) where the A-annulus is used for gas lift unless there is any other downhole device that is qualified as a well barrier in addition to what is found in the wellhead area;
   3) when analysis and/or risk assessment shows that any hydrocarbon volume in the annulus might have unacceptable consequences if the wellhead/surface well barrier is lost.

7.4 Well barrier elements acceptance criteria

7.4.1 General

Subclause 7.8 of this section lists the WBEs that constitute the primary and secondary barriers for situations that are illustrated.

7.4.2 Additional well barrier element (WBE) acceptance criteria

The following table describes features, requirements and guidelines that are additional to what is described in Clause 15.

No.	Element name	Additional features, requirements and guidelines
Table 1	Fluid column.	During completion operations there shall be sufficient fluid available on the location to cater for any situation that might develop. Typically this will require minimum additional 100 % well volume (including riser) of the same or alternative fluid to control the well.
Table 4	Drilling BOP.	When running completion assemblies, the drilling BOP shall be capable of shearing and sealing of/on the assembly, or one of the following criteria shall be met: a) It shall be possible to lower the assembly below the BOP by installation of a kick stand. b) It shall be possible to drop the string below the BOP. c) It shall be possible to close the BOP on a suitable joint within a kickstand distance.

7.4.3 Common well barrier elements (WBEs)

There are no defined common WBEs.

7.5 Well control action procedures and drills

7.5.1 Well control action procedures

The following table describes incident scenarios for which well control action procedures should be available (if applicable) to deal with the incidents should they occur. This list is not comprehensive and additional scenarios may be applied based on the actual planned activity, see 4.2.7.

Item	Description	Comments
1.	Well influx/inflow (kick) or fluid loss while running or pulling the completion string.	
2.	Running non shearable items across BOP shear rams.	
3.	Running completions with multiple control lines.	
4.	Planned or emergency disconnect of marine riser.	Applies to floaters.
5.	Drive or drift off.	Applies to DP vessels.

7.5.2 Well control action drills

It is recommended that drills are executed to practice on the above well control action procedures.

7.6 Completion string design

7.6.1 General

All components of the completion string including connections (i.e. tubing, packers, polished bore receptacle, nipples, mandrels, ASCSSV, valve bodies, SCSSV, plugs, etc.) shall be subject to load case verification.

Completion string design work shall

- ensure that completion string is designed to suit its purpose with a known degree of safety, and
- identify all completion string weak points (with respect to burst, collapse, tensile and compression strength).

Operator shall

a) Establish documented requirements for completion string design work.
   The document shall as a minimum describe operator's requirements as to how completion string design shall be performed, including acceptance criteria.
b) Establish documented requirements for completion string procurement, maintenance, preparation and in-the-well installation.

7.6.2 Design basis, premises and assumptions

As a minimum the following data shall be used to establish the dimensioning parameters for the design process:

a) Reservoir data.
b) Well data.
c) Production or injection data.
d) Fluid data.
e) Well control actions.
f) Interface or compatibility of fluids.
g) Well intervention methods and treatment.
h) Life expectancy.
i) Artificial lift requirements.

METP shall be established.

7.6.3 Load cases

When designing for burst, collapse and axial load, the following load cases shall minimum be considered. This list is not comprehensive and the operator need to prepare actual and applicable cases based on the planned activity:

Item	Description	Comments
1.	Leak testing of the completion string.	
2.	Leak testing annulus.	To test tubing hanger seal, and production packer from above if this is not possible from below by other means.
3.	Shut in of well.	Based on METP.
4.	Dynamic flowing conditions.	Special focus on temperature effects.
5.	Shut in of well by closing the SCSSV.	
6.	Should check tubing collapse as a function of minimum tubing pressure (plugged perforations or low test separator pressure) at the same time as a high operating annulus (maximum allowable) pressure is present.	Used to establish maximum allowable annulus pressure/tubing collapse in the bottom of the well.
7.	Injection	Water, well killing, stimulation, fracturing.
8.	Overpull	Stuck string, shear rating of pins/rings.
9.	Firing of TCP guns.	Applies if activation pressure governs METP.
10.		
11.	Artificial lift requirements.	Shut-in of annulus by closing ASCSSV and bleeding off above a) Evacuate annulus above gaslift valve. b) Maximum injection pressure.

7.6.4 Minimum design factors

The operator shall establish a set of minimum design safety factors, describing the minimum allowable safety margin for a specific load type. The factors shall be applicable to the design work and represent the minimum acceptance criteria for the design.

Minimum design safety factors shall be established for

- burst loads,
- collapse loads,
- axial loads,
- tri-axial loads.

For deterministic calculations of loads and ratings, the below factors are suggested as guidelines:

a) Burst: 1,10
b) Collapse: 1,10
c) Axial: 1,25
d) Tri-axial yield: 1,25 (pipe body and connection whichever combination is weaker)

As an alternative to the above design factors, stress design or stress verification programs might be employed to demonstrate the presence of appropriate design factor(s).

For probabilistic calculations of loads and ratings, the probability of failure should be less than $10^{-3,5}$.

The weakest point in the completion string shall be clearly identified with regards to burst, collapse and tensile strength rating.

For through tubing plugs, packers and valves, the design pressure shall be minimum 1,1 times the stated WP/maximum exposed load whichever is lower. These plugs, packers and valves shall be tested to MEDP or inflow tested.

7.6.5 Completion string equipment

The following completion string equipment shall be classified as part of the installation emergency shutdown system:

a) SCSSV
b) ASCSSV (if installed).
c) Production tree valves – wing valve, PMV.
d) Production tree valves serving chemical injection below master valves.
e) Production tree valves serving annulus gas lift valve (annulus master).

It shall be possible to install a tubing hanger plug (or a shallow set tubing plug) and a deep set tubing plug.

7.7 Other topics

7.7.1 Subsea wells (SSWs)

The A-annulus shall have continuous pressure recording and alarms.

When establishing the maximum tubing and casing differential pressure at seabed level, one shall use the METP less the annulus pressure at this level regarded as zero (not taking credit for liquid hydrostatic column from seabed to surface on the annulus side which can happen if the annulus is bled down following presence of gas).

7.7.2 Multipurpose wells

A multipurpose well is defined as a well that has transport of media to or from a formation interval via the A-annulus in addition to transport through the tubing. The following requirements and guidelines apply:

a) A-annulus shall
   1) have continuous pressure monitoring;
   2) be equipped with an ASCSSV, see 7.3 c.

b) B-annulus shall have continuous pressure monitoring with alarms. For SSWs the B-annulus (production and intermediate casing) shall be designed to withstand the thermal pressure build-up if possible, otherwise an acceptable pressure management system shall be implemented. If the production casing is not cemented into the intermediate casing, the exposed formation shall have a documented ability to withstand a leaking production casing scenario.
c) The intermediate casing shall be
    1) designed as a production casing for both planned and A-annulus fluid exposure during the well life;
    2) designed to withstand METP;
    3) pressure tested to METP prior to running production casing.
d) Production casing shall be designed as production tubing for both planned and well fluid exposure during the well life.
e) Production casing / liner cement should be cemented into the intermediate casing unless it can be documented that the formation can withstand METP (production casing leak scenario).
f) Annulus control lines and clamping arrangements shall be resistant to environmental loads (chemical exposure, temperature, pressure, mechanical wear, erosion, etc.).

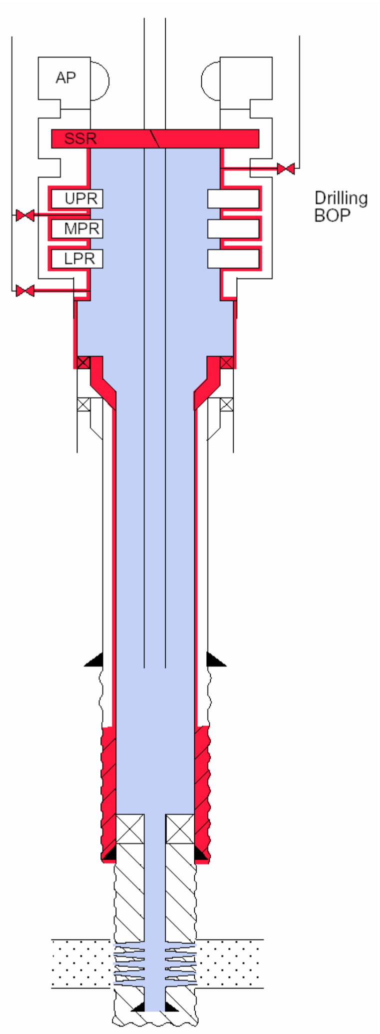
7.7.3 High pressure and high temperature (HPHT) wells

Specification and qualification criteria for equipment and fluids to be used or installed in a HPHT well shall be established, with particular emphasis on

a) dimensional stability of the well as a function of temperature and pressure,
b) sealing capability of metal to metal seals as a function of well bore fluids, pressure and temperature,
c) stability of explosive and chemical perforating charges as function of temperature/pressure exposure time,
d) clearance and tolerances as function of temperature and differential pressure exposure,
e) deterioration of elastomer seals and components as function of temperature/pressure exposure time and wellbore fluids.

7.8 Well barrier schematic illustrations

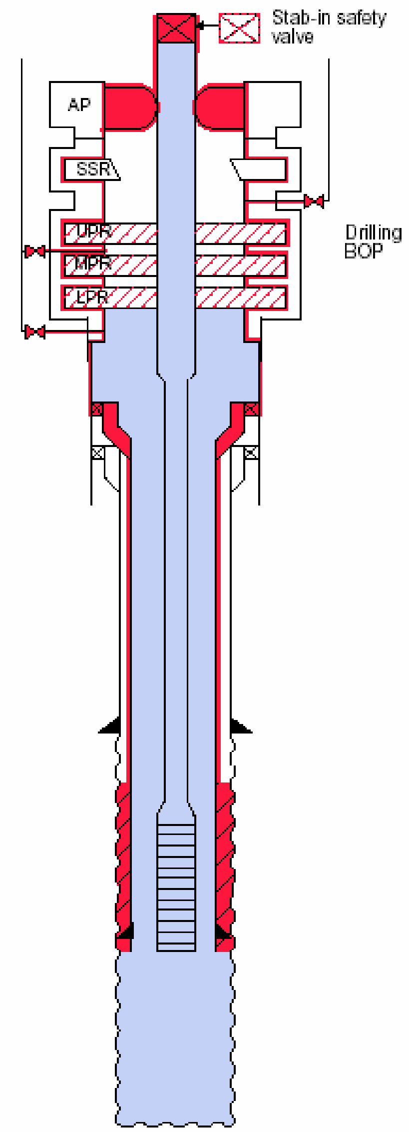
7.8.1 Running open end completion string



Well barrier elements	See Table	Comments
Primary well barrier		
1. Fluid column	1	
Secondary well barrier		
6. Casing cement	22	
7. Casing	2	
8. Wellhead	5	
9. High pressure riser	26	If installed.
10. Drilling BOP	4	

Note
None

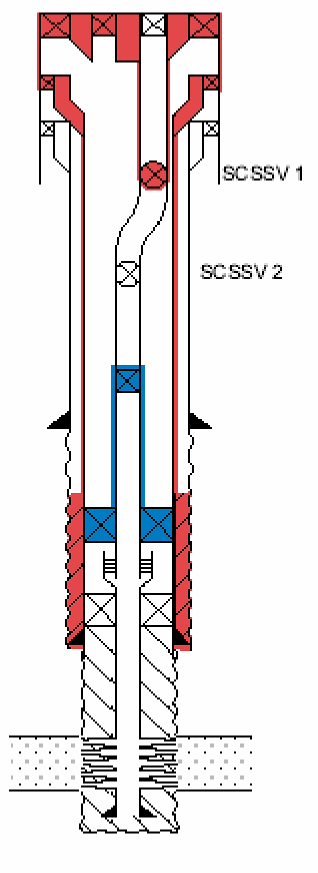
7.8.2 Running non-shearable items through BOP



Well barrier elements	See Table	Comments
Primary well barrier		
1. Fluid column	1	
Secondary well barrier		
1. Casing cement	22	
2. Casing	2	
3. Wellhead	5	
4. High pressure riser	26	If installed.
5. Drilling BOP	4	Minimum one pipe or annular preventer shall be able to seal the actual size of the non-shearable item.
6. Completion string	25	
7. Tubular string safety valve	40	

Note
None

7.8.3 Pulling BOP and landing subsea production tree



Well barrier elements	See Table	Comments
Primary well barrier		
1. Production packer	7	
2. Completion string	25	Between production packer and plug.
3. Deep set tubing plug	6	
Secondary well barrier		
1. Casing cement	22	
2. Casing	2	
3. Wellhead	5	
4. Tubing hanger	10	
5. Completion string	25	Above SCSSV..
6. SCSSV	8	A debris plug shall be installed in the tubing hanger production bore if the upper well barrier is a SCSSV.
7. Tubing hanger plug	11	Plug in annulus bore.

Note
None

8 Production

8.1 General

This clause covers requirements and guidelines pertaining to well integrity during production and injection from or to a reservoir. The production activity typically starts after the well construction team has handed the well over to production operations. The activity concludes with a handover back to drilling/well operations for intervention, workover or plug and abandonment. The clause focuses on maintenance of well integrity during production or injection activities, and parameters to be monitored.

This clause is written to be used by production operations. For practical purposes, some duplication or elaboration of requirements and guidelines from Clause 4 and the WBEAC occurs.

8.2 Well barrier schematics

It is recommended that WBSs are developed as a practical method to demonstrate and illustrate the presence of the defined primary and secondary well barriers in the well, see 4.2. In the table below there are a number of typical scenarios listed, some of which are also attached as illustrations. This table is not comprehensive and schematics for the actual situations during an activity or operations should be made.

Item	Description	Comments	See
1.	Typical platform well capable of flowing, shut-in.	None	8.8.1
2.	Typical gaslift platform production well.	None	8.8.2
3.	Typical subsea production well, vertical tree.	None	8.8.3
4.	Typical subsea production well, horisontal tree.	None	8.8.4

8.3 Well barrier schematics

Well barrier integrity is commonly monitored by registration of annulus pressure and frequent leak testing of WBEs.

The following apply:

a) Downhole safety valves, production tree valves and annulus valves shall be regularly leak tested. Leak test acceptance criteria shall be established and be available.
b) The pressure in all accessible annuli (A, B and/or C annuli) shall be monitored and maintained within minimum and maximum pressure range limits as defined in the completion design and presented in the hand-over or other relevant field documentation for the well.
c) Registered anomalies shall be investigated to determine the source of anomaly and if relevant, quantify any leak rate across the well barrier. When assessing a well barrier anomaly the following should to be taken into consideration:
    1) method of normalisation of the situation and restoring of two independent well barriers;
    2) gas and/or liquid leak rate across the well barrier;
    3) are the acceptance criteria for qualifying the well barrier maintained ?;
    4) possibility of deterioration of the leak;
    5) blow-out potential should the secondary well barrier fail.
d) Upon confirmation of loss of the defined well barrier, the production or injection shall be suspended and shall not re-commence before the well barrier or an alternative well barrier re-established.
e) If for any reason the well is contemplated for continued operation, the following shall apply:
    1) any well with a potential to flow to surface or seabed shall have two independent well barriers. If the well barrier status, availability or monitoring ability is altered, any continued use shall be supported by the subsequent points;
    2) a risk assessment shall be performed based on current reservoir/well condition and time factors in any continued use;
    3) any deterioration of the leak, or additional failure of a WBE, shall not significantly reduce the possibility of containing the hydrocarbon/pressure and normalising the well;
    4) a formal deviation process shall be implemented;
    5) any deviation from the original two defined well well barriers shall be presented to the authorities for information and/or approval for further use.

8.4 Well barrier elements acceptance criteria

8.4.1 General

Subclause 8.8 lists the WBEs that constitute the primary and secondary well barriers for situations that are illustrated.

8.4.2 Additional well barrier elements (WBEs) acceptance criteria

The following table describes features, requirements and guidelines that are additional to what is described in Clause 15.

<table>
<tr><th>No.</th><th>Element name</th><th>Additional features, requirements and guidelines</th></tr>
<tr><td>Table 8</td><td>Surface controlled sub surface safety valve</td><td rowspan="2">When applying the acceptance criteria as quoted in the well barrier acceptance criteria Table 8 and Table 9, the liquid/gas composition above the valve to be tested shall be known with certainty. For gas-liquid combinations special calculation formulas need to be developed. The acceptance criteria should be converted to basic pressure per time units for the individual wells or fields.</td></tr>
<tr><td>Table 9</td><td>Annulus surface controlled sub surface safety valve</td></tr>
<tr><td>Table 31</td><td>Subsea production tree</td><td rowspan="2">Production tree valves of floating gate design shall be tested in the direction of flow. As this is not practical for the master valves these may be inflow tested to well pressure. Acceptance of production tree valve tests may utilise the API RP 14B requirements providing the observation volume is adequately large to give meaningful test.</td></tr>
<tr><td>Table 33</td><td>Surface production tree</td></tr>
</table>

8.4.3 Common well barrier elements (WBEs)

There are no defined common WBEs

8.5 Well control action procedures and drills

This is not applicable for production activities, as the live well will be secured by closure of primary or secondary well barrier from the central control room.

8.6 Production/injection philosophy and parameters

The production/injection philosophy and operating parameters shall at all times remain within the boundaries of the well and completion design.

The given functionality (production, injection, gas lift, etc.) and maximum allowable operating parameters (pressure, temperature, flow rates, etc.) shall be established. If at any times the functionality or established values are to be exceeded, a well design verification shall be undertaken to ascertain that the existing design is able to handle the new load scenario.

8.7 Other topics

8.7.1 Handover documentation from well construction team to production operations

Any well design feature of significance to the safety or operating efficiency of the well shall be clearly identified in the hand-over documents for the well, which should contain the following:

a) An installation certificate shall be issued, including well completion data, well barrier test charts, equipment tag number, valve and fluid status.
b) Recommended minimum and maximum operating annulus pressure shall be presented.
c) Recommended guidelines for starting up gaslift with or without liquid in the annulus shall be available as part of the handover documentation.
d) Recommended procedure for closing and opening of SCSSVs as part of normal operation and leak testing shall be included.
e) Acceptance criteria for leakrate while leak testing valves in the well or production tree shall be converted to pressure units per time unit and be included in the handover documentation. The effect of variation of gas oil ratio or media composition over time needs to be accommodated for.

f) Non-compliance or deviation from the established requirements and guidelines should be discussed with the well construction team.

8.7.2 Sand production

It shall be assumed that most wells in sandstone reservoirs have a given ability to produce sand. The sand production performance of each individual well should be monitored continuously or as a minimum at frequent intervals (downhole, subsea or at surface). Threshold values for maximum allowable sand production should be established. Erosion loss in the flow conduit from the reservoir and to the entry of the first stage separator should be estimated or measured, and compared with maximum allowable wear loss.

8.7.3 Scale/asphaltenes

Scale deposits in the well might cause flow restrictions, or render valves inoperable (SCSSVs and zone inflow control valves). The effect of injection/produced water on the production performance shall be known through studies and chemical analysis. Where the operating conditions are within the scale formation regime, a scale dissolver and/or a scale inhibitor programs shall be considered established. Any restricting effect resulting from gas injection should also be considered.

Injected chemicals shall have a confirmed compatibility with the well material and effluent.

8.7.4 Hydrates

The potential for forming of hydrates in flow conduits shall be assessed, with particular focus on SCSSVs, production tree valves, annulus bleed-down system and other WBEs that may be affected. Procedures for hydrate prevention (injection of anti freeze agents) shall be established, including leak testing of valves, and when shutting in a well for a longer period.

8.7.5 Annulus bleed systems

The annulus bleed system shall be liquid filled at all times if possible. When gas has been bleed off from the annulus, the annulus bleed system should be replenished with liquid. The need for hydrate inhibition shall be considered.

Annulus master valve and ASCSSV shall be kept in open position at all times.

The annulus pressure behaviour shall be monitored to correspond with well shut-in pressure and temperature variation in the tubing that will affect the annulus pressure. Any sign of non-conformance shall trigger an investigation of the event.

8.7.6 Gas lift and multi purpose wells

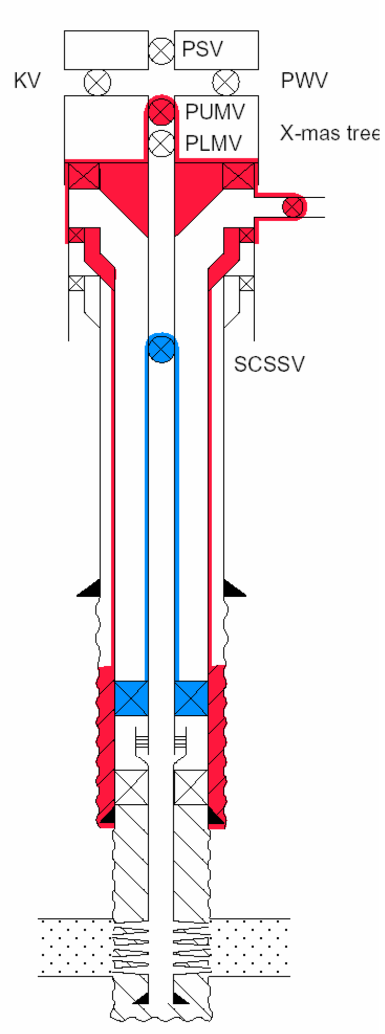
Gas lift and multi purpose wells with transport of media in both tubing and annulus will be subject to monitoring of the B-annulus. For SSWs the B-annulus shall be designed to withstand the thermal pressure build-up if possible, otherwise an acceptable pressure management system shall be implemented. If the production casing is not cemented into the intermediate casing, the exposed formation shall have a documented ability to withstand a leaking production casing scenario.

8.7.7 Zone controlled wells

Wells with zone control and inner string placed inside a perforated liner should be particularly monitored for sand production. Sand production through the perforations in the liner is known to cause erosions in the tubing and/or control lines of the lower completion. When sand production breakthrough occurs an effort should be made to identify the contributing zone and choke this back in order to reduce the effect of any potential sand erosion.

8.8 Well barrier schematic illustrations

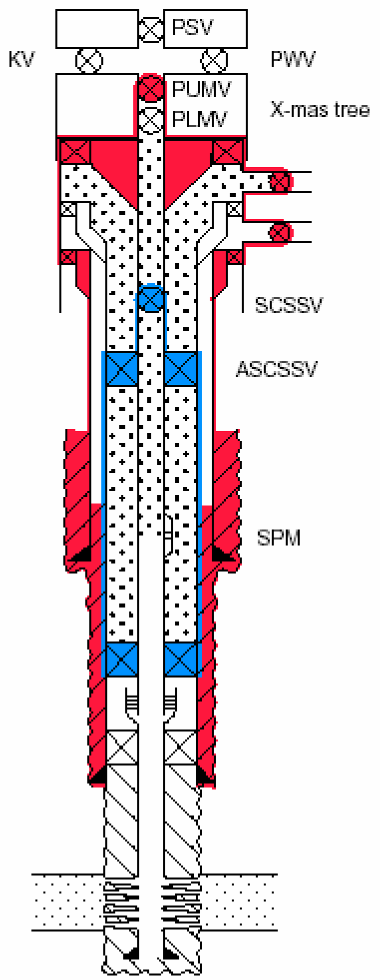
8.8.1 Typical well capable of flowing - Shut-in



Well barrier elements	See Table	Comments
Primary well barrier		
1. Production packer	7	
2. Completion string	25	Tubing between SCSSV and production packer.
3. SCSSV	8	
Secondary well barrier		
1. Casing cement	22	
2. Casing	2	
3. Wellhead	5	Casing hanger, tubing head with connectors.
4. Tubing hanger	10	
5. Annulus access line and valve	12	
6. Production tree	33	Body and master valve.

Note
None

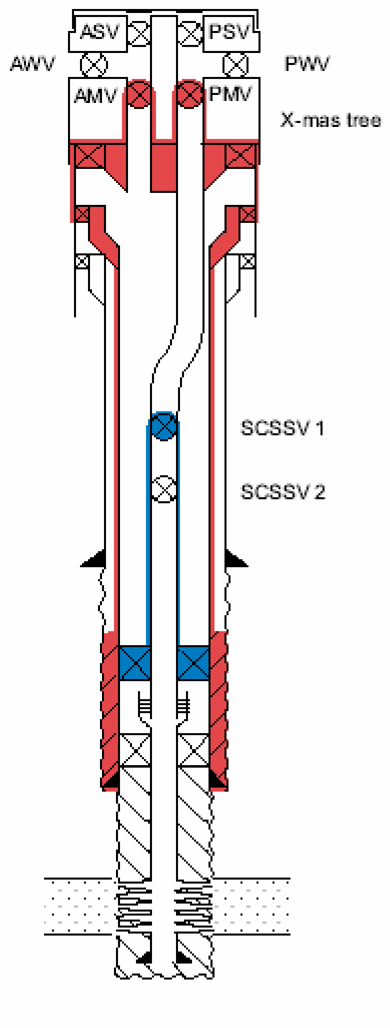
8.8.2 Typical gaslift platform production well



Well barrier elements	See Table	Comments
Primary well barrier		
1. Production packer	7	
2. Casing	2	Between ASCSSV packer and production packer.
3. ASCSSV	9	
4. Completion string	25	Between ASCSSV and SCSSV.
5. SCSSV	8	
Secondary well barrier		
1. Casing cement	22	Production casing cement.
2. Casing	2	Production casing and casing into intermediate casing.
3. Casing cement	22	Intermediate casing cement.
4. Casing	2	Intermediate casing.
5. Wellhead	5	Intermediate casing hanger w/seals.
6. Tubing hanger	10	
7. Annulus access line and valve	12	Tubing head w/annulus gas injection line w/valve.
8. Surface production tree	33	W/master valve.
9. Annulus access line and valve	12	B-annulus access line w/valve.

Note
None

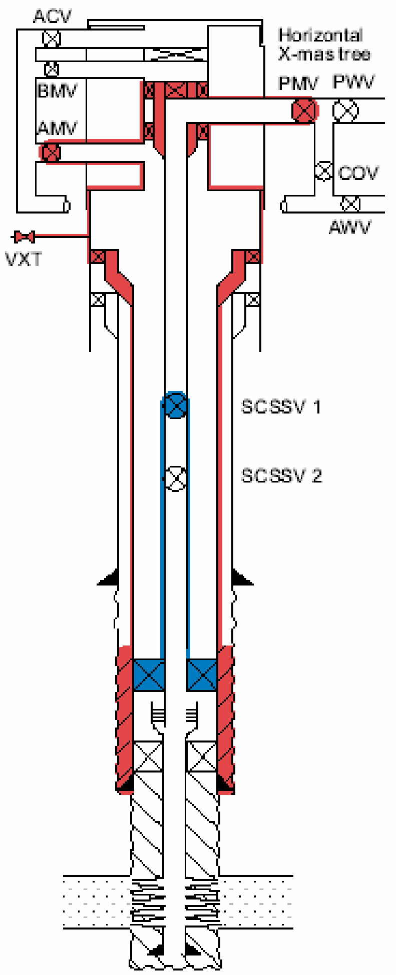
8.8.3 Typical subsea production well with vertical production tree



Well barrier elements	See Table	Comments
Primary well barrier		
Production packer	7	
Completion string	25	Production tubing between SCSSV and production packer.
SCSSV	8	SCSSV 1 or SCSSV 2.
Secondary well barrier		
Casing cement	22	
Casing	2	
Wellhead	5	W/ casing hanger and seals.
Tubing hanger	10	
Subsea production tree	33	Annulus bore w/master valve, production bore w/master valve.

Note
None

8.8.4 Typical subsea production well with horizontal production tree



Well barrier elements	See Table	Comments
Primary well barrier		
Production packer	7	
Completion string	25	Production tubing between production packer and SCSSV.
SCSSV	8	SCSSV 1 or SCSSV 2.
Secondary well barrier		
Casing cement	22	
Casing	2	
Wellhead	5	Including casing hanger.
Tubing hanger	10	
Tubing hanger plug	11	
Subsea production tree	31	w/AMV and PMV.

Note
None

9 Sidetracks, suspension and abandonment

9.1 General

This section covers requirements and guidelines pertaining to well integrity during plugging of wells in connection with

- temporary suspension of well activities and operations,
- temporary or permanent abandonment of wells,
- permanent abandonment of a section of a well (side tracking, slot recovery) to construct a new wellbore with a new geological well target.

The purpose of this section is to describe the establishment of well barriers by use of WBEs and additional features required to execute this activity in a safe manner, with focus on isolation of permeable formations/reservoirs/sources of outflow, both from each other in the wellbore, and from surface.

Requirements for isolation of formations, fluids and pressures for temporary and permanent abandonment are the same. However, choice of WBEs may be different to account for abandonment time, and ability to re-enter the well, or resume operations after temporary abandonment.

9.2 Well barrier schematics

It is recommended that WBSs are developed as a practical method to demonstrate and illustrate the presence of the defined primary and secondary well barriers in the well, see 4.2. In the table below there are a number of typical scenarios listed, some of which are also attached as illustrations. The table is not comprehensive and schematics for the actual situations during an activity or operation should be made.

Item	Description	Comments	See
1.	Temporary abandonment – Non- perforated well.	Non-completed well.	9.8.1
2.	Temporary abandonment – Perforated well with BOP or production tree removed.	With well completion installed.	9.8.2
3.	Permanent abandonment - Open hole.		9.8.3
4.	Permanent abandonment – Perforated well.		9.8.4
5.	Permanent abandonment - Multibore with slotted liners or sandscreens.	Covers permanent zonal isolation of multiple reservoirs.	9.8.5
6.	Permanent abandonment - Slotted liners in multiple reservoirs.	Applies also to slot recovery/ side tracks, etc.	9.8.6
7.	Suspension - Hang-off/disconnect of mariner riser.	Hang-off drill pipe.	9.8.7

9.3 Well barrier acceptance criteria

9.3.1 Function and type of well barriers

For wells to be permanently abandoned, with several sources of inflow, the usual; one primary and one secondary well barrier, do not suffice. Hence, this subclause covers all well barriers and the functions they are intended to fulfil which may be necessary in abandonment scenarios. These well barriers may, however, not be applicable for wells where continued operations are planned, where the wellhead/ well control equipment is utilised and capable, as a secondary well barrier, to cover any source of inflow in the well. This also means that some terms used in this subclause are only applicable in the context of suspension and abandonment of wells and wellbores.

The following individual or combined well barriers shall be a result of well plugging activities:

Name	Function	Purpose
Primary well barrier.	First well barrier against flow of formation fluids to surface, or to secure a last open hole.	To isolate a potential source of inflow from surface.
Secondary well barrier, reservoir.	Back-up to the primary well barrier.	Same purpose as the primary well barrier, and applies where the potential source of inflow is also a reservoir (w/ flow potential and/ or hydrocarbons).
Well barrier between reservoirs.	To isolate reservoirs from each other.	To reduce potential for flow between reservoirs.
Open hole to surface well barrier.	To isolate an open hole from surface, which is exposed whilst plugging the well.	"Fail-safe" well barrier, where a potential source of inflow is exposed after e.g. a casing cut.
Secondary well barrier, temporary abandonment.	Second, independent well barrier in connection with drilling and well activities.	To ensure safe re-connection to a temporary abandoned well, and applies consequently only where well activities has not been concluded.

The functions of a well barrier and a plug can be combined should it fulfil more than one of the abovementioned objectives (except a secondary well barrier can never be a primary well barrier for the same reservoir).

A secondary well barrier for one reservoir formation may act as a primary well barrier for a shallower formation, if this well barrier is designed to meet the requirements of both formations.

9.3.2 Positioning of well barriers

Well barriers should be installed as close to the potential source of inflow as possible, covering all possible leak paths.

The primary and secondary well barriers shall be positioned at a depth where the estimated formation fracture pressure at the base of the plug is in excess of the potential internal pressure.

The final position of the well barrier/WBEs shall be verified.

9.3.3 Materials

The materials used in well barriers for plugging of wells shall withstand the load/ environmental conditions it may be exposed to for the time the well will be abandoned. Tests should be performed to document long term integrity of plugging materials used.

9.3.4 Leak testing and verification

When inflow testing or leak testing from above to verify the integrity of a well barrier is not possible, or when this may not give conclusive results, other means of ensuring proper installation of a well barrier shall be used. Verification through assessment of job planning and actual job performance parameters are options available.

Inflow tests shall be documented.

9.3.5 Sidetracking

The original wellbore shall be permanently abandoned prior to a side-track/ slot recovery.

9.3.6 Suspension

Suspension of operations requires the same number of well barriers as other abandonment activities. However, the need for WBE testing, and verification, can be compensated by monitoring of its performance, such as fluid level/ pressure development above well barriers. Well fluids (see Table 1) may in such cases be qualified as a WBE.

9.3.7 Temporary abandonment

It shall be possible to re-enter temporarily abandoned wells in a safe manner.

Integrity of materials used for temporary abandonment should be ensured for the planned abandonment period times two. Hence, a mechanical well barrier may be acceptable for temporary abandonment, subject to type, planned abandonment period and subsurface environment.

Degradation of casing body should be considered for longer temporary abandonment scenarios.

Temporarily abandoned subsea wellheads and templates shall be protected from external loads in areas with fishing activities, or other seabed activities etc. Hence for deep water wells, temporary seabed protection can be omitted if there is confirmation of no such activities in the area and at the depth of the abandoned seabed installations.

The pressure in tubing and annulus above the reservoir well barrier ("A" annulus) shall be monitored if a subsea completed well is planned abandoned for more than one year. An acceptable alternative if monitoring is not practicable may be to install a deep set well barrier plug.

For surface completed wells, it should be possible to monitor the pressure in the "A" annulus and in the last tubular that was installed (production tubing, casing).

9.3.8 Permanent abandonment

9.3.8.1 General

Permanently plugged wells shall be abandoned with an eternal perspective, i.e. for the purpose of evaluating the effect on the well barriers installed after any foreseeable chemical and geological process has taken place.

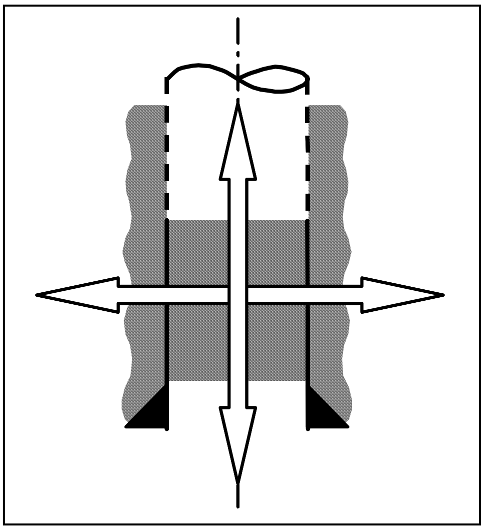
There shall be at least one well barrier between surface and a potential source of inflow, unless it is a reservoir (contains hydrocarbons and/ or has a flow potential) where two well barriers are required.

When plugging a reservoir, due attention to the possibilities to access this section of the well (in case of collapse, etc) and successfully install a specific WBE should be paid.

The last open hole section of a wellbore shall not be abandoned permanently without installing a permanent well barrier, regardless of pressure or flow potential. The complete borehole shall be isolated.

9.3.8.2 Permanent well barriers

Permanent well barriers shall extend across the full cross section of the well, include all annuli and seal both vertically and horizontally (see illustration). Hence, a WBE set inside a casing, as part of a permanent well barrier, shall be located in a depth interval where there is a WBE with verified quality in all annuli.



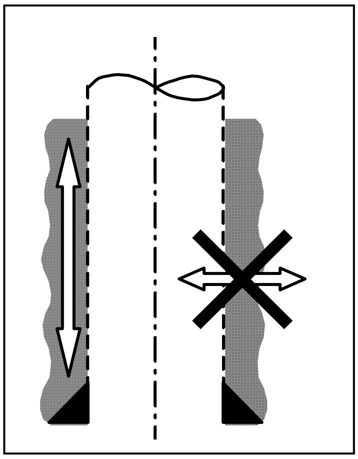
A permanent well barrier should have the following properties:

a) Impermeable
b) Long term integrity.
c) Non shrinking.
d) Ductile – (non brittle) – able to withstand mechanical loads/ impact.
e) Resistance to different chemicals/ substances (H_2S, CO_2 and hydrocarbons).
f) Wetting, to ensure bonding to steel.

Steel tubular is not an acceptable permanent WBE unless it is supported by cement, or a plugging material with similar functional properties as listed above, (inside and outside).

Elastomer seals used as sealing components in WBEs are not acceptable for permanent well barriers.

The presence and pressure integrity of casing cement shall be verified to assess the along hole pressure integrity of this WBE. The cement in annulus will not qualify as a WBE across the well (see illustration).



Open hole cement plugs can be used as a well barrier between reservoirs. It should, as far as practicably possible, also be used as a primary well barrier, see Table 24.

Cement in the liner lap, which has not been leak tested from above (before a possible liner top packer has been set) shall not be regarded a permanent WBE.

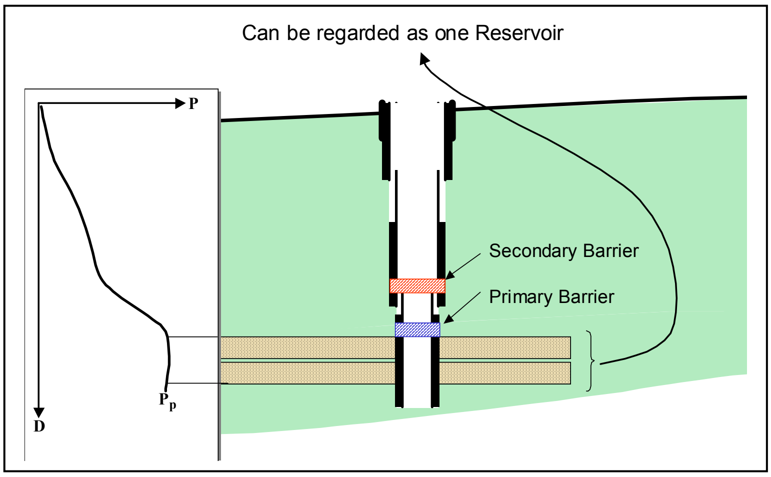
Removal of downhole equipment is not required as long as the integrity of the well barriers is achieved.

Control cables and lines shall be removed from areas where permanent well barriers are installed, since they may create vertical leak paths through the well barrier.

When well completion tubulars are left in hole and permanent plugs are installed through and around the tubular, reliable methods and procedures to install and verify position of the plug inside the tubular and in the tubular annulus shall be established.

9.3.8.3 Special requirements

Multiple reservoir zones/ perforations located within the same pressure regime, isolated with a well barrier in between, can be regarded as one reservoir for which a primary and secondary well barrier shall be installed (see illustration).



9.4 Well barrier elements acceptance criteria

9.4.1 General

Subclause 9.8 lists the WBEs that constitute the primary and secondary barriers for situations that are illustrated.

9.4.2 Additional well barrier elements (WBEs) acceptance criteria

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

No.	Element name	Additional features, requirements and guidelines
Table 2	Casing	Accepted as permanent WBE if cement is present inside and outside.
Table 22	Casing cement	Accepted as a permanent WBE together with casing and cement inside the casing. Should alternative materials be used for the same function a separate WBEAC shall be developed.
Table 24	Cement plug	Cased hole cement plugs used in permanent abandonment shall be set in areas with verified cement in casing annulus. Should alternative materials be used for the same function a separate WBEAC shall be developed. A cement plug installed using a pressure tested mechanical plug as a foundation should be verified by documenting the strength development using a sample slurry subjected to an ultrasonic compressive strength analysis or one that have been tested under representative temperature and/or pressure.

No.	Element name	Additional features, requirements and guidelines
Table 25	Completion string	Accepted as permanent WBE if cement is present inside and outside the tubing.
Table 43	Liner top packer	Not accepted as a permanent WBE.

9.4.3 Common well barrier elements (WBEs)

A risk analysis shall be performed and risk reducing measures applied to reduce the risk as low as reasonable practicable, see 4.2.3.3.

The following table describes risk reducing measures that can be applied when a WBE is an element in the primary and secondary well barrier:

No	Element name	Failure scenario	Probability reducing measures	Consequence reducing measures
Table 2	Casing	Leak through casing and into annulus, with possibility of fracturing formation below previous casing shoe.	None	Cement in the annulus with verified TOC above the section that is common.

9.5 Well control action procedures and drills

9.5.1 Well control action procedures

The following table describes incident scenarios for which well control action procedures should be available (if applicable) to deal with the incidents should they occur. This list is not comprehensive and additional scenarios may be applied based on the actual planned activity, see 4.2.7.

Item	Description	Comments
1.	Cutting of casing.	Trapped gas pressure in casing annulus.
2.	(SSW) Pulling casing hanger seal assembly.	Trapped gas pressure in casing annulus.
3.	Re-entry of suspended or temporary abandoned wells.	Account for trapped pressure under plugs due to possible failure of suspension plugs.

9.5.2 Well control action drills

The following well control action drills should be performed:

Item	Description	Comments
1.	Pressure build-up, or lost circulation in connection with a cutting casing operation.	To verify crew response in applying correct well control practices.
2.	Loss of well barrier whilst performing inflow test.	

9.6 Suspension, plugging and abandonment design

9.6.1 Design basis, premises and assumptions

Depths and size of permeable formations with a flow potential in any wellbore shall be known.

All elements of the well barrier shall withstand the pressure differential across the well barrier at time of installation and as long as the well barrier will be in use, see 9.3.3.

The following information should be gathered as a basis of the well barrier design and abandonment programme:

a) Well configuration (original, intermediate and present) including depths and specification of permeable formations, casing strings, primary cement behind casing status, well bores, side-tracks, etc.
b) Stratigraphic sequence of each wellbore showing reservoir(s) and information about their current and future production potential, where reservoir fluids and pressures (initial, current and in an eternal perspective) are included.
c) Logs, data and information from primary cementing operations in the well.
d) Estimated formation fracture gradient.
e) Specific well conditions such as scale build up, casing wear, collapsed casing, fill, or similar issues.

The design of abandonment well barriers consisting of cement should account for uncertainties relating to

- downhole placement techniques,
- minimum volumes required to mix a homogenous slurry,
- surface volume control,
- pump efficiency/ -parameters,
- contamination of fluids,
- shrinkage of cement.

9.6.2 Load cases

Functional and environmental loads shall be combined in the most unfavourable way.

For permanently abandoned wells, the specific gravity of well fluid accounted for in the design shall maximum be equal to a seawater gradient.

The following load cases should be applied for the abandonment design:

Item	Description	Comments
1.	Minimum depth of primary and secondary well barriers for each reservoir/potential source of inflow, taking the worst anticipated reservoir pressure for the abandonment period into account.	Not shallower than formation strength at these depths. Reservoir pressure may for permanent abandonment revert to initial/virgin level.
2.	Leak testing of casing plugs.	Criteria as given in Table 24.
3.	Burst limitations on casing string at the depths where abandonment plugs are installed.	Cannot set plug higher than what the burst rating allows (less wear factors).
4.	Collapse loads from seabed subsidence or reservoir compaction.	The effects of seabed subsidence above or in connection with the reservoir shall be included.

9.6.3 Minimum design factors

The design factors shall be as described in 5.6.4 and 7.6.4.

9.7 Other topics

9.7.1 Risks

Risk shall be assessed relating to time effects on well barriers such as long term development of reservoir pressure, possible deterioration of materials used, sagging of weight materials in well fluids, etc.

HSE risks related to removal and handling of possible scale in production tubing shall be considered in connection with plugging of development wells.

HSE risk relating to cutting of tubular goods, detecting and releasing of trapped pressure and recovery of materials with unknown status shall be assessed.

9.7.2 Removing equipment above seabed

Use of explosives to cut casing is acceptable only if measures are implemented (directed/ shaped charges and upward protection) which reduces the risk to surrounding environment to the same level as other means of cutting casing.

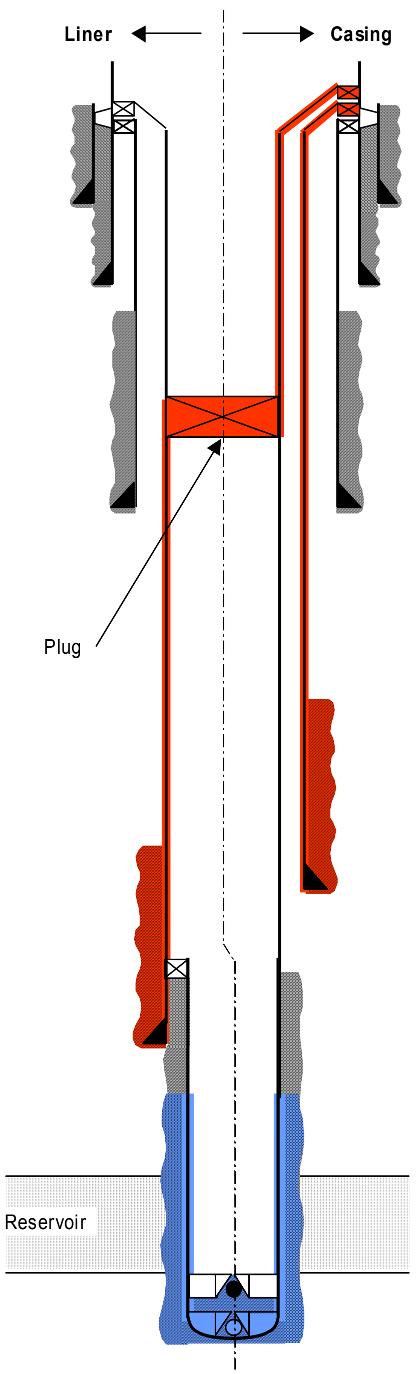
For permanent abandonment wells, the wellhead and the following casings shall be removed such that no parts of the well ever will protrude the seabed.

Required cutting depth below seabed should be considered in each case, and be based on prevailing local conditions such as soil, sea bed scouring, sea current erosion, etc.. The cutting depth should be 5 m below seabed.

No other obstructions related to the drilling and well activities shall be left behind on the sea floor.

9.8 Attachments – Well barrier schematics (WBS)

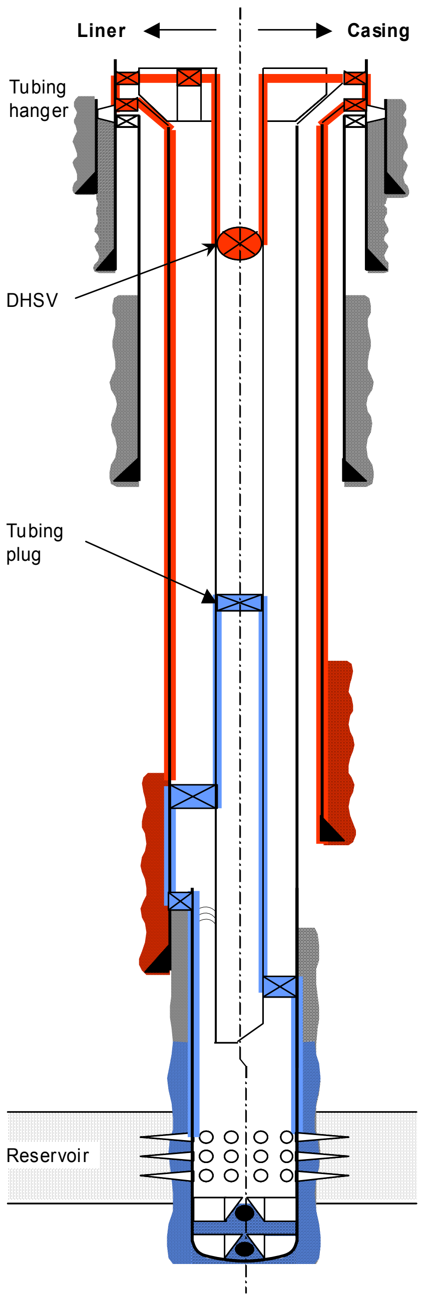
9.8.1 Temporary abandonment – Non-perforated well



Well barrier elements	See Table	Comments
Primary well barrier, last open hole		
1. Cement plug	24	Shoe track.
2. Casing (liner) cement	22	
3. Casing (reservoir liner)	2	Un-perforated w/2 each float valves.
or		
1. Cement plug	24	Shoe track.
2. Casing cement	22	
3. Reservoir casing	2	Un-perforated w/2 each float valves.
Secondary well barrier, temporary abandonment		
1. Casing	2	
2. Casing cement	22	
3. Cement plug or mechanical plug	24 28	Shallow plug.
or		
1. Casing cement	22	
2. Casing	2	Intermediate
3. Wellhead	5	
4. Casing	2	Production casing.
5. Cement plug or mechanical plug	24 28	Shallow plug.

Note
None

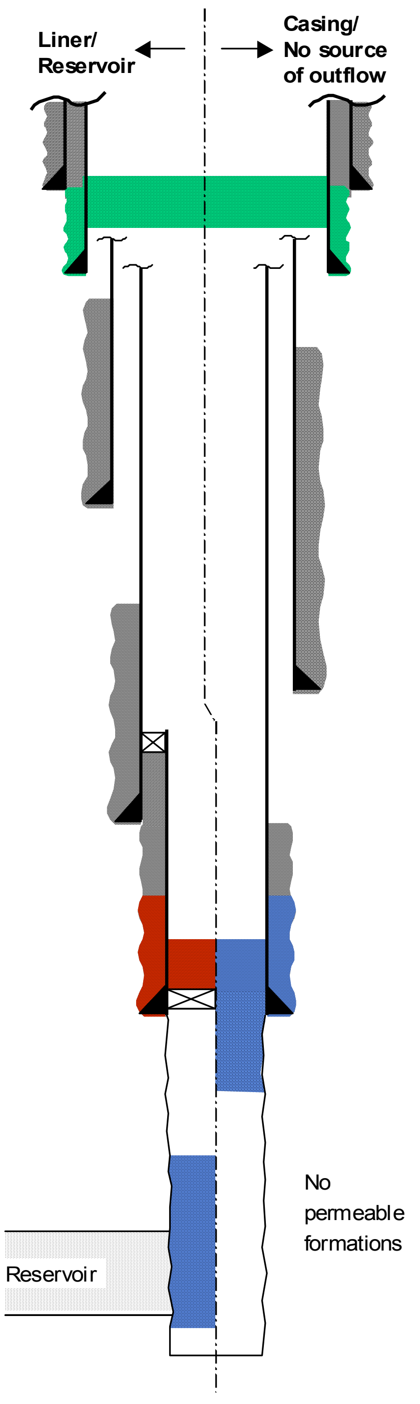
9.8.2 Temporary abandonment – Perforated well with BOP or production tree removed



Well barrier elements	See Table	Comments
Primary well barrier		
1. Casing (liner) cement	22	
2. Casing (liner)	2	Liner above perforations.
3. Liner top packer	43	
4. Casing	2	Below production packer.
5. Production packer	7	50 m below TOC in casing annulus.
6. Completion string	25	
7. Deep set tubing plug	6	
or,		
1. Casing cement	22	
2. Casing	2	Above perforations.
3. Production packer	7	
4. Completion string	25	
5. Deep set tubing plug	6	
Secondary well barrier, reservoir		
1. Casing cement	22	Above production packer.
2. Casing	2	Common WBE, between liner top packer and production packer.
3. Wellhead	5	
4. Tubing hanger	10	
5. Tubing hanger plug	11	For SSWs.
6. Completion string	25	Down to SCSSV.
7. SCSSV	8	
or,		
1. Casing cement	22	Intermediate casing.
2. Casing	2	Intermediate casing.
3. Wellhead	5	
4. Tubing hanger	10	
5. Tubing hanger plug	11	For SSWs.
6. Completion string	25	Down to SCSSV.
7. SCSSV	8	

Note
None

9.8.3 Permanent abandonment - Open hole



Well barrier elements	See Table	Comments
Primary well barrier		
1. Cement plug	24	Open hole.
or, (“**primary well barrier, last open hole**”):		
1. Casing cement	22	
2. Cement plug	24	Transition plug across casing shoe.
Secondary well barrier, reservoir		
1. Casing cement	22	
2. Cement plug	24	Cased hole cement plug installed on top of a mechanical plug.
Open hole to surface well barrier		
1. Cement plug	24	Cased hole cement plug.
2. Casing cement	22	Surface casing.

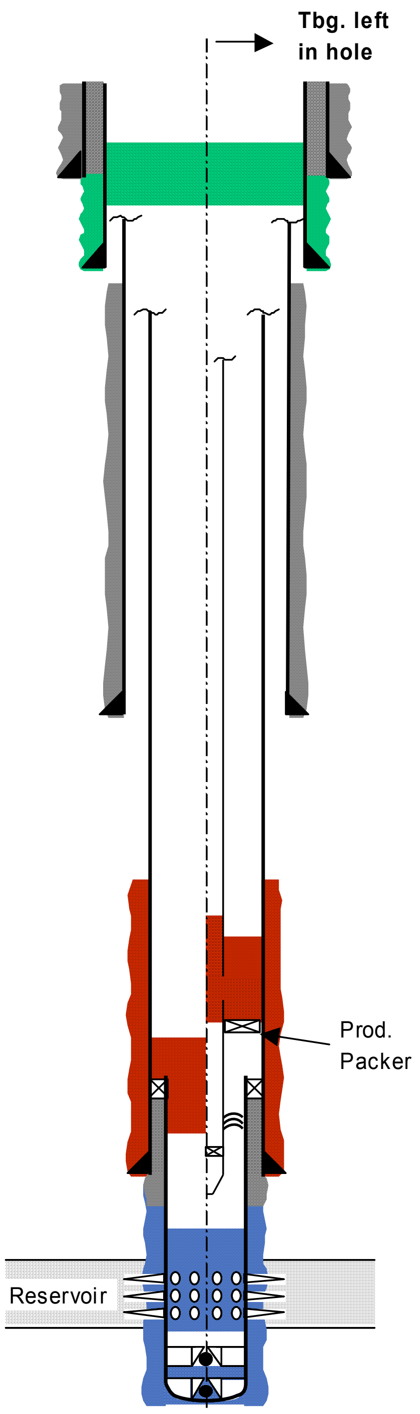
Notes

a. Verification of primary well barrier in the “liner case” to be carried out as detailed in Table 22.

b. The well barrier in deepest casing shoe can for both cases be designed either way, if casing/liner cement is verified and O.K.

c. The secondary well barrier shall as a minimum be positioned at a depth where the estimated formation fracture pressure exceeds the contained pressure below the well barrier.

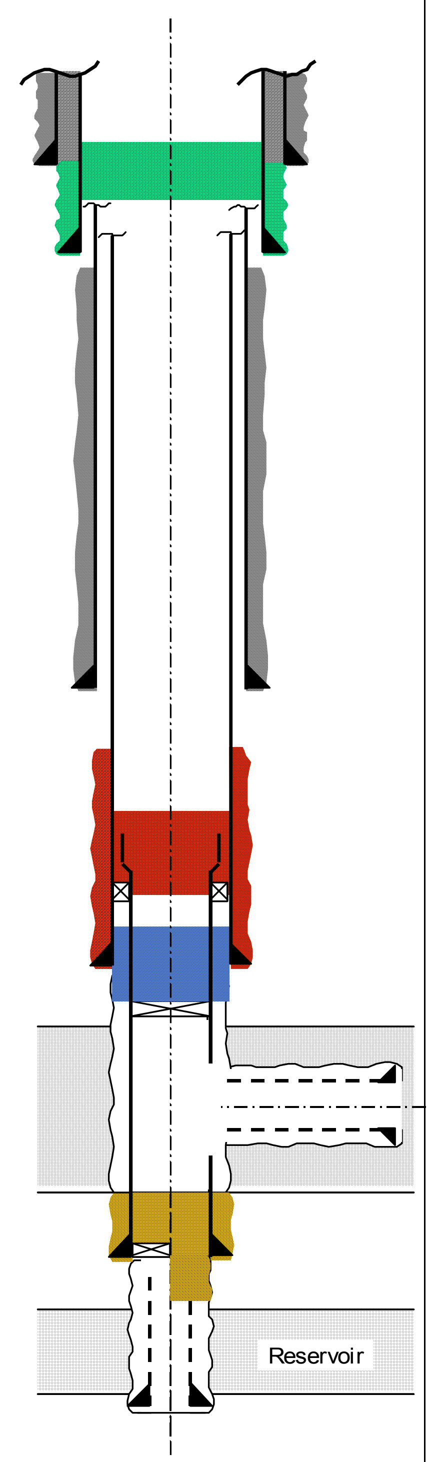
9.8.4 Permanent abandonment - Perforated well



Well barrier elements	See Table	Comments
Primary well barrier		
1. Liner cement	22	
2. Cement plug	24	Across and above perforations.
Secondary well barrier, reservoir		
1. Casing cement	22	
2. Cement plug	24	Across liner top.
or, for tubing left in hole case:		
1. Casing cement	22	
2. Cement plug	24	Inside and outside of tubing.
Open holes to surface well barrier		
1. Cement plug	24	
2. Casing cement	22	Surface casing.

Notes
1. Cement plugs inside casing shall be set in areas with verified cement in casing annulus.
2. The secondary well barrier shall as a minimum be positioned at a depth where the estimated formation fracture pressure exceeds the contained pressure below the well barrier.

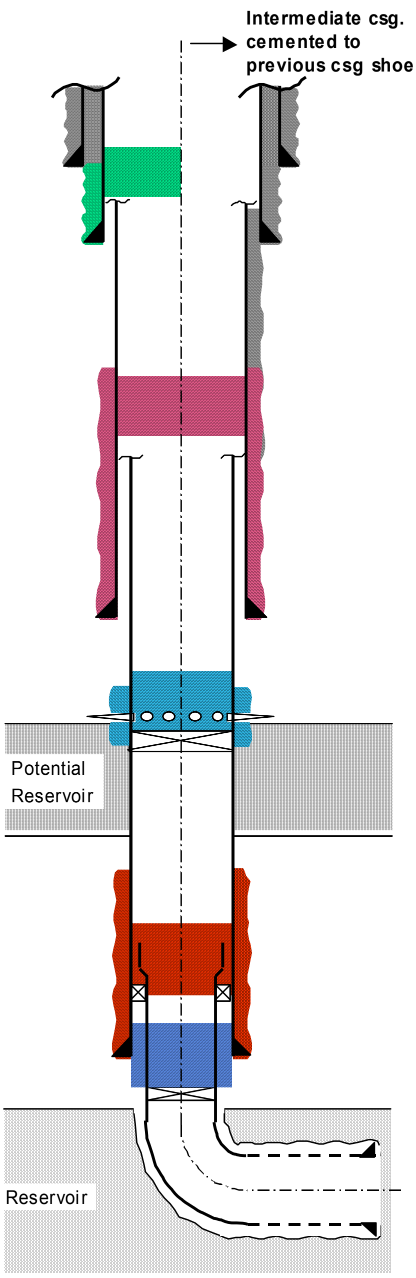
9.8.5 Permanent abandonment - Multibore with slotted liners or sand screens



Well barrier elements	See Table	Comments
Barrier between reservoirs		
1. Casing cement	22	
2. Cement plug	24	Cased hole.
or,		
2. Cement plug	24	Transition plug across casing shoe.
Primary well barrier		
1. Cement plug	24	Across wellbore and casing shoe.
Secondary well barrier, reservoir		
1. Casing cement	22	
2. Cement plug	24	Casing plug across liner top.
Open Holes to surface wellbarrier		
1. Cement plug	24	Cased hole cement plug.
2. Casing cement	22	Surface casing.

Notes
1. The “well barrier between reservoirs” may act as the primary well barrier for the “deep” reservoir, and “primary well barrier” may be the secondary well barrier for “deep” reservoir, if the latter is designed to take the differential pressures for both formations.
2. Secondary well barrier shall not be set higher than the formation integrity at this depth, considering that the design criteria may be initial reservoir pressure, as applicable in each case.

9.8.6 Permanent abandonment - Slotted liners in multiple reservoirs

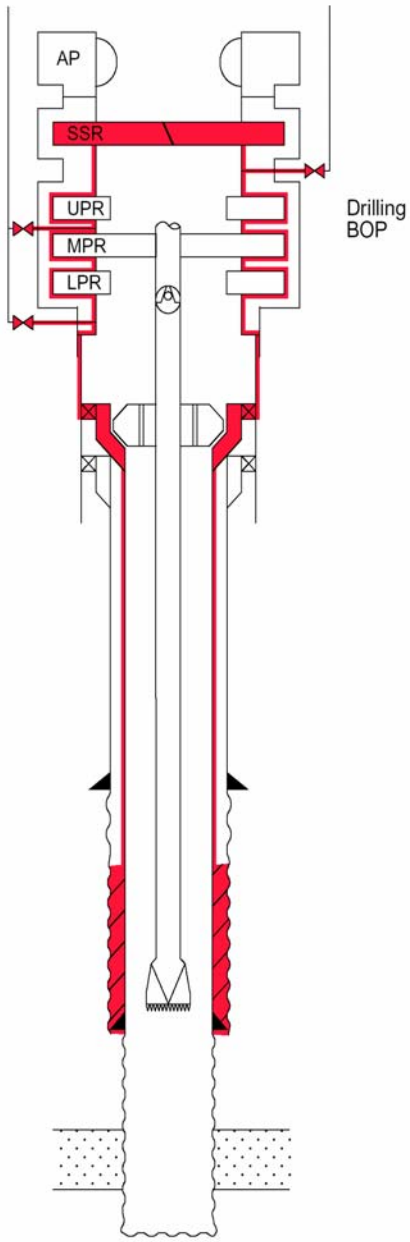


Well barrier elements	See Table	Comments
Primary well barrier, deep reservoir		
1. Cement plug	24	Through liner and across casing shoe/Open hole transition.
Secondary well barrier		
1. Casing cement	22	
2. Cement plug	24	Across liner top.
Primary well barrier, shallow reservoir		
1. Cement plug	22	Squeezed into perforated casing annulus above potential reservoir.
Secondary well barrier, shallow reservoir		
1. Casing cement	22	
2. Cement plug	24	
Open holes to surface well barrier		
3) Cement plug	24	Cased hole.
4) Casing cement	22	Surface casing.

Notes

1. Secondary well barrier shall not be set higher than the formation integrity at this depth, considering that the design criteria may be initial reservoir pressure, which may develop over time.
2. The case on the right hand side indicates that the intermediate casing string is cemented into surface casing, i.e. with no open annulus to surface. Hence, no open holes to surface well barrier is required.

9.8.7 Suspension - Hang-off/Disconnect of mariner riser



Well barrier elements	See Table	Comments
Primary well barrier		
1. Fluid column	1	Time limited barrier, see Note 1.
Secondary well barrier		
1. Casing cement	22	Last casing.
2. Casing	2	
3. Wellhead	5	
4. BOP	4	

Notes

1. Well bore fluid shall be qualified through test for the hang-off period.
2. A "storm valve" should be installed in the drillpipe hang-off assembly

10 Wireline operations

10.1 General

This clause covers requirements and guidelines pertaining to welll integrity during 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 clause is to describe the establishment of well barriers by use of WBEs and additional features required to execute this activity in a safe manner.

10.2 Well barrier schematics

It is recommended that WBSs are developed as a practical method to demonstrate and illustrate the presence of the defined primary and secondary well barriers in the well, see 4.2. In the table below there are a number of typical scenarios listed, some of which are also attached as illustrations. The table is not comprehensive and schematics for the actual situations during an activity or operation should be made.

Item	Description	Comments	See
1.	Rigging WL equipment above surface production tree.		10.8.1
2.	Running WL through surface production tree.		10.8.2
3.	Running WL through vertical subsea production tree with LRP.		10.8.3
4.	Running WL through horizontal subsea production tree - Drilling BOP and SSTT installed.		10.8.4
5.	Pipe conveyed wireline logging.		10.8.5

10.3 Well barrier acceptance criteria

The following requirements and guidelines apply:

a) Surface well control equipment for a slickline operation in a completed well should consist of
   1) stuffing box, including a device that will seal of the wellbore in the event the slickline breaks and is ejected from the wellbore;
   2) lubricator;
   3) WL BOP (slickline ram maintaining pressure from below);
   4) WL safety head (shear/seal ram with independent hydraulic operation).
b) Surface well control equipment for braided or electric cable operations in a completed well should consist of
   1) grease injection head including a device that will seal of the wellbore in the event the cable breaks and is ejected from the wellbore, stuffing box and sufficient number of flow tubes to contain the applicable well pressure taking into account cable size and gas content in well;
   2) lubricator;
   3) WL BOP (cable ram maintaining pressure from below);
   4) WL BOP (cable ram maintaining pressure from above);
   5) WL safety head (shear/seal ram with independent hydraulic operation);
   6) system for injecting grease between cable rams to prevent gas migration through cable armour.

c) It is recommended to use a tool catcher, tool trap or similar device to protect the valve below against damage in the event of accidentially dropping the toolstring during operation.
d) 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, see. 10.4.2.
e) 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.

f) 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 an other 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.
g) 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 R/U (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.
h) 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.
i) 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 for how to act if such tools or components are positioned across the WL safety head in critical situations should be available.
j) 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.
k) 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

10.4.1 General

Subclause 10.8 lists the WBEs that constitute the primary and secondary barriers for situations that are illustrated.

10.4.2 Additional well barrier elements (WBEs) acceptance criteria

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

No.	Element name	Additional features, requirements and guidelines
Table 32	Subsea test tree.	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.
Table 38	WL safety head.	If other valves below the safety head fulfil its requirements according to NORSOK D-002, they can replace the safety head.

10.4.3 Common well barrier elements (WBEs)

A risk analysis shall be performed and risk reducing measures applied to reduce the risk as low as reasonable practicable, see 4.2.3.3. The following table describes risk reducing measures that can be applied when a WBE is an element in the primary and secondary well barrier:

No.	Element name	Failure scenario	Probability reducing measures	Consequence reducing measures
Table 2	Casing (below production packer).	Leak through the body.	No requirements defined.	No requirements defined.
Table 22	Casing cement.	Break-down and leak through the cement.	No requirements defined.	No requirements defined.
Table 42	Lower riser package.	Leak through the body or connection seals.	Leak test prior to operation.	Kill inlet prepared with double valve for connection of pumping line.
Table 31	Subsea production tree.	Leak through the body, outlet valves or connection seals.	Leak test prior to operation.	Kill inlet prepared with double valve for connection of pumping line.
Table 33	Surface production tree.	Leak through the body, outlet valves or connection seals.	Leak test prior to operation.	Kill inlet prepared with double valve for connection of pumping line.
Table 10	Tubing hanger.	Leak through the body.	Leak test prior to operation.	Kill inlet prepared with double valve for connection of pumping line.
Table 38	Wireline safety head.	Leak through the body.	Leak test prior to operation.	Kill inlet prepared with double valve for connection of pumping line.

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 (if applicable) to deal with the incidents should they occur. This list is not comprehensive and additional scenarios may be applied based on the actual planned activity, see 4.2.6.

Item	Description	Comments
1.	Loss of air-supply during operation.	Fixed and floating installation.
2.	Loss of winch power or mechanical failure.	Fixed and floating installation.
3.	External leak in lubricator/tool catcher.	Fixed and floating installation.
4.	External leak in WL BOP body.	Fixed and floating installation.
5.	External leak below WL BOP safety head.	Fixed and floating installation.
6.	Broken cable blown out of well.	Fixed and floating installation.
7.	Leak in stuffing box/grease head.	Fixed and floating installation.
8.	Leak in WL BOP cable ram.	Fixed and floating installation.
9.	Leak in WL BOP safety head (shear/seal).	Fixed and floating installation.
10.	Leak in the surface production tree hydraulic master valve while lubricating against swab valve.	Fixed installation.
11.	Leak in lubricator valve while lubricating against lubricator valve.	Floating installation.
12.	Leak in test string below SSTT.	Floating installation.
13.	External leak in landing string.	Floating installation.
14.	External leak in riser above or below LRP.	Floating installation.
15.	Controlled disconnect.	Floating installation.

Item	Description	Comments
16.	Emergency disconnect.	Floating installation
17.	Emergency situation on rig/platform.	Fixed and floating installation.
18.	Influx in well during logging on wireline.	Logging without pressure control equipment on fixed and floating installation.
19.	Influx in well during wireline pipe conveyed logging with side entry sub **above** drilling BOP.	Logging without pressure control.equipment on fixed and floating installation.
20.	Influx in well during wireline pipe conveyed logging with side entry sub **below** drilling BOP.	Logging without pressure control equipment on fixed and floating installation.
21.	H_2S gas in work area.	Fixed and floating installation.

10.5.2 Well control action drills

The following well control action drills should be performed:

Type	Frequency	Objective	Comments
Well control action procedure, see 10.5.1.	Once per week for both day and night shift.	Response training.	The selected procedure shall be relevant for the ongoing operation.

10.6 Well design

The assembly of WL toolstrings should take into account operational limitations regarding pressure and temperature.

Any limitations to maximum pull on sheaves, WL mast, cable, toolstrings, weakpoints etc. should be identified prior to start of operation.

10.7 Other topics

10.7.1 Hydrate prevention

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

10.7.2 Other safety considerations

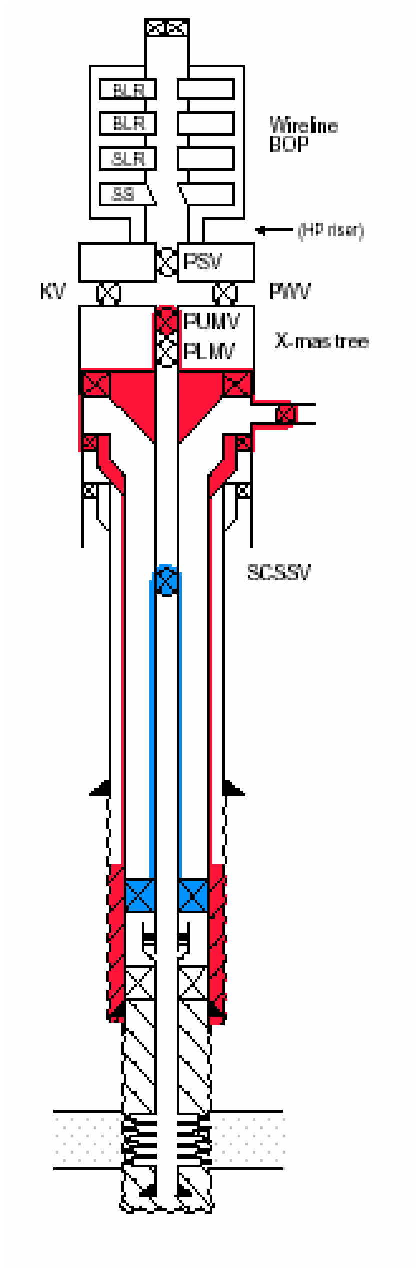
WL equipment connections shall be qualified and certified to withstand the static and dynamic forces, bending moments and pressures that may be encountered during operation.

To prevent excessive loads from being applied to the WL sheaves or cable, and to prevent accidental breaking of the cable head weakpoint, it is recommended that the WL winch is equipped with an adjustable overpull shut down system.

It is recommended that the WL winch is equipped with a data acquisition system that continuously monitor, record, and store depth and cable tension data on a digital media.

10.8 Well barrier schematic illustrations

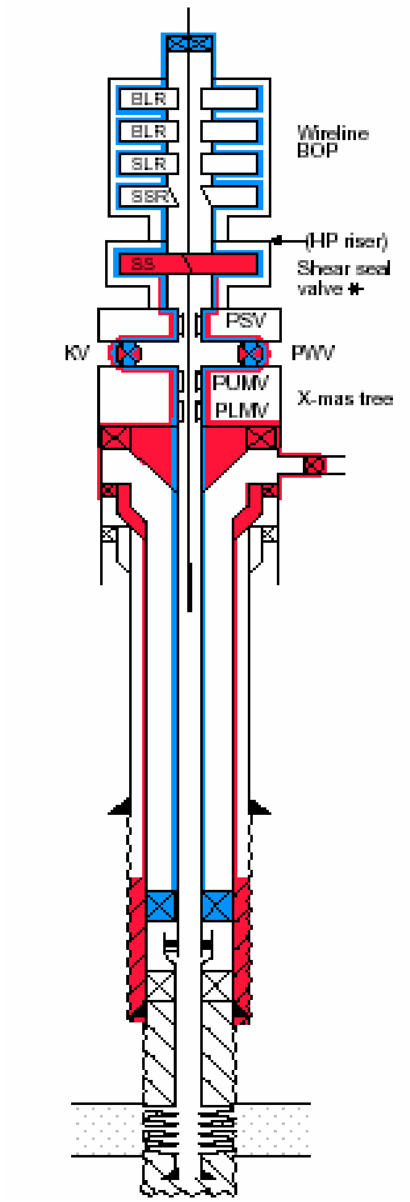
10.8.1 Rigging WL equipment above surface production tree



Well barrier elements	See Table	Comments
Primary well barrier		
1. Casing cement	22	
2. Casing	2	Below production packer.
3. Production packer	7	
4. Completion string	25	Below the SCSSV.
5. SCSSV	8	
Secondary well barrier		
1. Casing cement	22	Common WBE with primary well barrier.
2. Casing	2	Common WBE with primary well barrier below production packer.
3. Wellhead	5	Including casing hanger and access lines with valves.
4. Tubing hanger	10	Including tubing hanger and access lines with valves.
5. Surface production tree	33	Closed master valve.

Notes
1. See 10.4.3 for compensating measures for common WBE.
2. Legend:
   - BLR = WL BOP cable ram
   - SLR = WL BOP slickline ram
   - SS = WL safety head (shear/seal ram), rigged up close to Xmas tree

10.8.2 Running WL through surface production tree

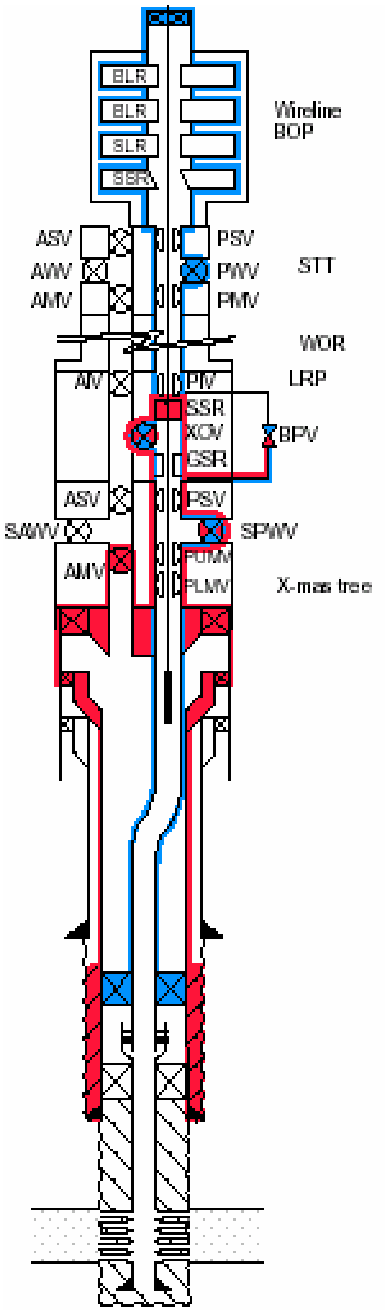


Well barrier elements	See Table	Comments
Primary well barrier		
1. Casing cement	22	
2. Casing	2	Below production packer.
3. Production packer	7	
4. Completion string	25	
5. Tubing hanger	10	
6. Surface production tree	33	Including kill and PWVs.
7. Wireline BOP	37	Body only. Act as back up element to the wireline stuffing box/grease head.
8. Wireline lubricator	44	
9. Wireline stuffing box/grease head	39	
Secondary well barrier		
1. Casing cement	22	Common WBE with primary well barrier.
2. Casing	2	Common WBE with primary well barrier below production packer.
3. Wellhead	5	Including casing hanger and access lines with valves.
4. Tubing hanger	10	Common WBE with primary well barrier.
5. Surface production tree	33	Common WBE with primary well barrier.
6. Wireline safety head	38	Common WBE with primary well barrier.

Notes

1. See 10.4.3 for compensating measures for common WBE.
2. The WL safety head should be rigged up as close as possible to the surface production tree.
3. If a triple or quad wireline BOP including a safety head is used, but is not installed as close as possible to the surface production tree, than a separate WL safety head should be installed.
4. Legend:
   - BLR = WL BOP cable ram
   - SLR = WL BOP slickline ram
   - SSR = WL BOP cut valve, integrated in WL BOP
   - SS = WL safety head (shear/seal ram) rigged up close to Xmas tree

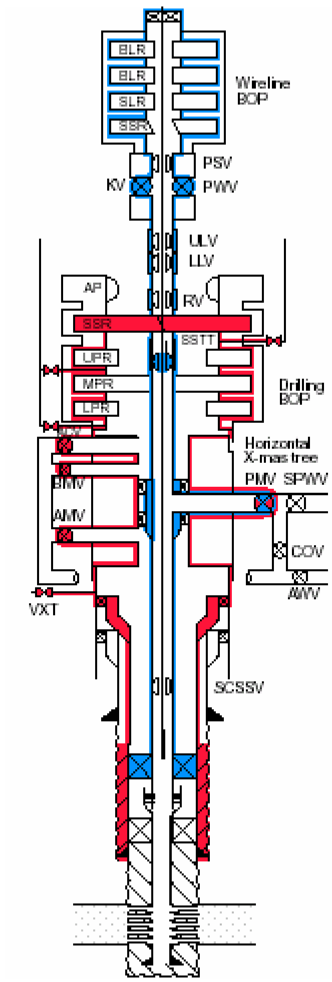
10.8.3 Running WL through vertical subsea production tree with LRP



Well barrier elements	See Table	Comments
Primary well barrier		
1. Casing cement	22	
2. Casing	2	Below production packer.
3. Production packer	7	
4. Completion string	25	
5. Tubing hanger	10	
6. Subsea production tree	31	Body and PWV.
7. Lower riser package	42	Connectors, body and x-over valve and by-pass valve.
8. High pressure riser	26	Workover riser.
9. Surface test tree	34	Body and PWV.
10. Wireline safety head	38	Body
11. Wireline BOP	37	Body only. Act as back up element to the wireline stuffing box/grease head.
12. Wireline lubricator	44	
13. Wireline stuffing box/grease head	39	
Secondary well barrier		
1. Casing cement	22	Common WBE with primary well barrier.
2. Casing	2	Common WBE with primary well barrier below production packer.
3. Wellhead	5	Including casing hanger and access lines with valves.
4. Tubing hanger	10	Common WBE with primary well barrier.
5. Subsea production tree	31	Body, AMV, and PWV. PWV is common WBE with primary well barrier.
6. Lower riser package	42	Connectors, body, XOV, BPV and SSR. Body, XOV and BPV are common WBE with primary well barrier.

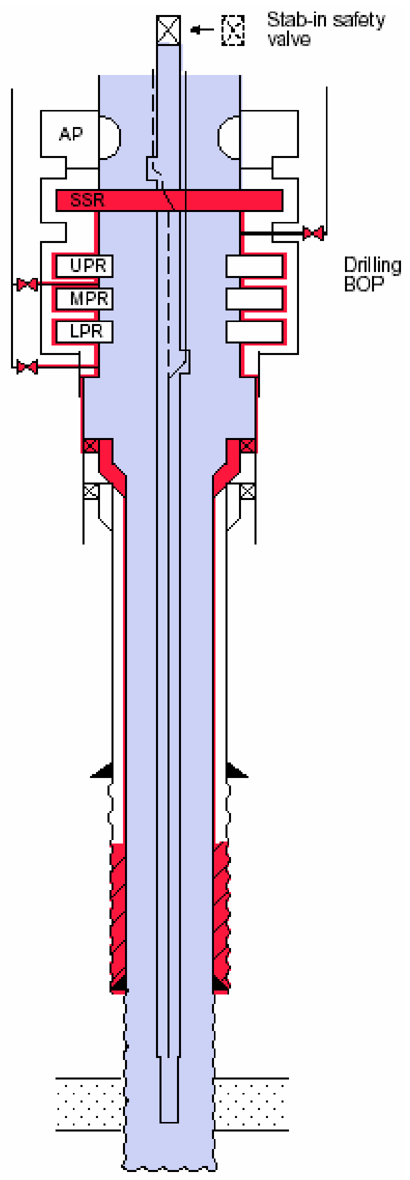
Notes
1. See 10.4.3 for compensating measures for common WBE.
2. Legend:
   - BLR = WL BOP cable ram
   - SLR = WL BOP slickline ram
   - SS = WL safety head (shear/seal ram),

10.8.4 Running WL through horizontal subsea production tree - Drilling BOP and SSTT installed



Well barrier elements	See Table	Comments
Primary well barrier		
1. Casing cement	22	
2. Casing	2	Below production packer.
3. Production packer	7	
4. Completion string	25	
5. Tubing hanger	10	
6. Subsea production tree	31	Body and PMV.
7. High pressure riser	26	Landing string/workover riser.
8. Surface test tree	32	Body, kill wing valve and surface PWV.
9. Wireline safety head	38	Body
10. Wireline BOP	37	Body only. Act as back up element to the wireline stuffing box/grease head.
11. Wireline lubricator	44	
12. Wireline stuffing box/grease head	39	
Secondary well barrier		
1. Casing cement	22	Common WBE with primary well barrier.
2. Casing	2	Common WBE with primary well barrier below production packer.
3. Wellhead	5	Including casing hanger and access lines with valves.
4. Tubing hanger	10	Tubing hanger and access lines with valves is a common WBE with the primary well barrier.
5. Subsea production tree	31	Body and PMV and AMV. The PMV is a common WBE with the primary well barrier.
6. Drilling BOP	4	Body, shear seal ram and BPVs.

Notes
1. See 10.4.3 for compensating measures for common WBE.
2. Legend:
   - BLR = WL BOP cable ram
   - SLR = WL BOP slickline ram
   - SS = WL safety head (shear/seal ram).

10.8.5 Pipe conveyed wireline logging


Well barrier elements	See Table	Comments
Primary well barrier		
1. Fluid column	1	.
Secondary well barrier		
1. Casing cement	22	
2. Casing	2	
3. Wellhead	5	
4. High pressure riser	26	If installed.
5. Drilling BOP	4	Body, shear seal ram and BPVs.

Note

1. Applies to all wireline operations where the fluid column constitute the primary well barrier e.g. for wireline, wireline tractor or pipe conveyed logging operations in open hole.
2. Prior to operation the sealing capability of the drilling BOP rams and annular preventer, with cable outside of the drill pipe, should be known.

11 Coiled tubing operations

11.1 General

This clause covers requirements and guidelines pertaining to well integrity during CT operations. A CT operation is a technique for deployment of various tools (logging tools, drilling tools, packers, etc.) and as a conduit for circulating or placing fluids in the well. CT can be deployed in pressurised wells or in dead wells.

The purpose of this clause is to describe the establishment of well barriers by use of WBEs and additional features required to execute this activity in a safe manner.

11.2 Well barrier schematics

It is recommended that WBSs are developed as a practical method to demonstrate and illustrate the presence of the defined primary and secondary barriers in the well, see 4.2. In the table below there are a number of typical scenarios listed, some of which are also attached as illustrations. The table is not comprehensive and schematics for the actual situations during an activity or operation should be made.

Item	Description	Comments	See
1.	Rigging CT equipment above production tree.		11.8.1
2.	Running CT through surface production tree.		11.8.2
3.	Running CT through vertical subsea production tree with LRP.		11.8.3
4.	Running CT through horizontal subsea production tree with drilling BOP and SSTT.		11.8.4
5.	Running CT tubing through horizontal sub-sea production tree with LRP.		

11.3 Well barrier acceptance criteria

The following requirements and guidelines apply:

a) Surface well control equipment for a CT operation in a completed well should consists of
   1) CT stripper;
   2) CT BOP;
   3) high pressure riser;
   4) CT safety head.
b) All connections from the production tree to the top of the CT BOP shall be flanged or clamped and have metal to metal seals. Alternative connections and seals may be used when qualified specifically for the intended purpose (subsea riser, etc.).
c) Valve inlets or outlets in the surface control rig-up shall be double with flanged or clamped connections. The inner valve shall be bi-directional with metal-to-metal seal in the bore. One of the two valves shall be remotely operated. Alternatively on inlets, the remote operated valve may be replaced by a manual valve and a check valve.
d) A pressure rated line shall be connected to the kill inlet of the surface well control equipment.
e) If the SCSSV is leaking, a safety head shall be installed and leak tested prior to rigging up the CT well control equipment.
f) A method for monitoring volume in surface pits and maintaining the fluid level in the well shall be in place when deploying long BHA in an open well. The monitoring system shall be able to measure the displacement of the BHA.
g) When deploying a long BHA that cannot be cut, a contingency joint and/or a system for dropping the BHA in the well shall be in place.
h) The shear/seal ram on the LRP is the upper closure device in the secondary well barrier when running CT in completed SSWs. The same requirements therefore apply to the LRP shear/seal ram as for the 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 CT in SSWs. Consequently, the

shear/seal ram in the subsea drilling BOP will have the same requirements as the safety head on fixed installations.

j) A two well barrier situation is still maintained if the CT is parted or ruptured above the stripper and it is verified that
    1) there is no influx of well fluids in the CT string;
    2) the check valves are not leaking.

11.4 Well barrier elements acceptance criteria

11.4.1 General

Subclause 11.8 lists the WBEs that constitute the primary and secondary barriers for situations that are illustrated.

11.4.2 Additional well barrier elements (WBEs) acceptance criteria

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

No.	Element name	Additional features, requirements and guidelines
Table 16	CT safety head.	If other valves below the safety head fulfil its requirements according to NORSOK D-002, they can replace the safety head.
Table 32	Subsea test tree.	The function of the SSTT is to seal off the test string or workover riser with or without CT present. The lower valve in the SSTT shall be capable of shearing one CT string including any wire, electric line or capillary line 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. the SSTT valves will constitute the upper closure device in the primary well barrier after disconnect when the SCSSV is not available. 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.

11.4.3 Common well barrier elements (WBEs)

A risk analysis shall be performed and risk reducing measures applied to reduce the risk as low as reasonable practicable, see 4.2.3.3. The following table describes risk reducing measures that can be applied when a WBE is an element in the primary and secondary well barrier:

WBE No.	Element name	Failure scenario	Probability reducing measures	Consequence reducing measures
Table 2	Casing (below production packer).	Leak through the body.	No requirements defined.	No requirements defined.
Table 22	Casing cement.	Break-down and leak through the cement.	No requirements defined.	No requirements defined.
Table 16	Coiled tubing safety head (body).	Leak through the body or connection seals.	Leak test prior to operation.	Kill fluid available for immediate use.
Table 42	Lower riser package.	Leak through the body or connection seals.	Leak test prior to operation.	Kill fluid available for immediate use.
Table 31	Subsea production tree.	Leak through the body, outlet valves or connection seals.	Leak test prior to operation.	Kill fluid available for immediate use.
Table 33	Surface production tree.	Leak through the body, outlet valves or connection seals.	Leak test prior to operation.	Kill fluid available for immediate use.
Table 10	Tubing hanger.	Leak through the body.	Leak test prior to operation.	Kill fluid available for immediate use.

11.5 Well control action procedures and drills

11.5.1 Well control action procedures

The following table describes incident scenarios for which well control action procedures should be available (if applicable) to deal with the incidents should they occur. This list is not comprehensive and additional scenarios may be applied based on the actual planned activity, see 4.2.6.

Item	Description	Comments
1.	Power unit, injector head, tubing reel or control system failure.	Fixed and floating installation.
2.	Well fluid return system failure.	Fixed and floating installation.
3.	Circulating system or pumping failure.	Fixed and floating installation.
4.	CT string runaway.	Fixed and floating installation.
5.	Leak in the CT string.	Fixed and floating installation.
6.	Collapsed CT string.	Fixed and floating installation.
7.	Stuck CT string.	Fixed and floating installation.
8.	Leak in the CT upper stripper.	Fixed and floating installation.
9.	Leak in the CT BOP pipe ram.	Fixed and floating installation.
10.	Leak in the CT BOP shear/seal ram.	Fixed and floating installation.
11.	External leak in riser below safety head.	Fixed installation.
12.	External leak in riser above safety head.	Fixed installation.
13.	Leak in the hydraulic master valve while lubricating BHA against swab valve.	Fixed installation.
14.	Lubricating long BHA into a dead well.	Fixed and floating installation.
15.	Leak in lubricator valve while lubricating BHA against lubricator valve.	Floating installation.
16.	Leak in test string below SSTT.	Floating installation.
17.	External leak in landing string.	Floating installation.
18.	External leak in riser above or below LRP	Floating installation.
19.	Controlled disconnect.	Floating installation.
20.	Emergency disconnect.	Floating installation.
21.	Emergency situation on rig/platform.	Fixed and floating installation.

Item	Description	Comments
22.	Running non-shearable tools across CT safety head	Fixed and floating installation.

11.5.2 Well control action drills

The following well control action drills should be performed:

Type	Frequency	Objective	Comments
Well control action procedure, see 11.5.1.	Once per week.	Response training.	The selected procedure shall be relevant for the ongoing operation.

11.6 Well design

There are no specific requirements or guidelines relating to well design.

11.7 Other topics

11.7.1 Hydrate prevention

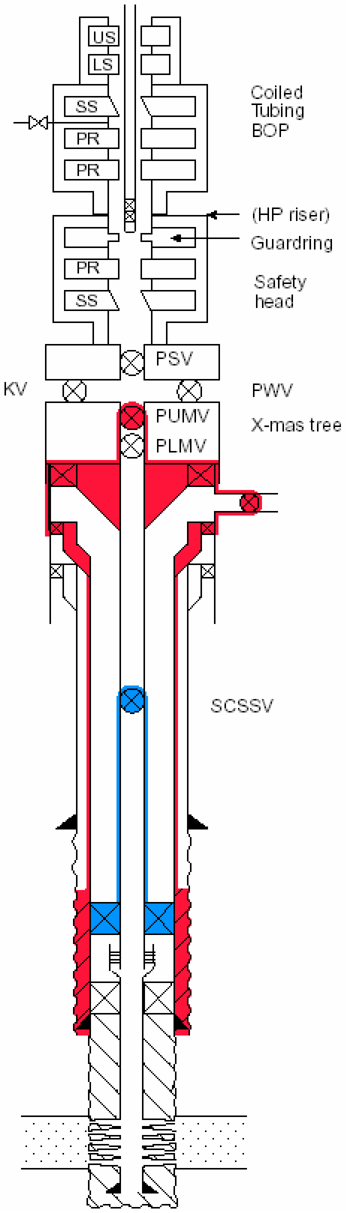
A hydrate-inhibited fluid shall be used when there is a risk for forming hydrates.

11.7.2 Floater specific operating and safety requirements

Because of the heave motion between the CT reel and gooseneck, precautions shall be made to prevent activation of the reel break by mistake. If the reel brake is automatically activated in the event of lost hydraulic pressure, this function should be overridden.

11.8 Well barrier schematic illustrations

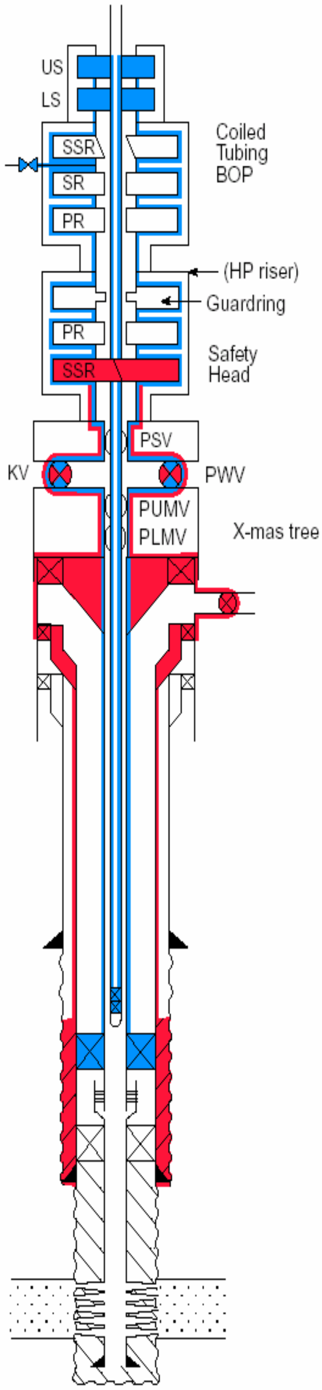
11.8.1 Rigging CT equipment above production tree



Well barrier elements	See Table	Comments
Primary well barrier		
1. Casing cement	22	
2. Casing	2	
3. Production packer	7	
4. Completion string	25	Below SCSSV
5. SCSSV	8	
Secondary well barrier		
1. Casing cement	22	Common WBE with primary well barrier.
2. Casing	2	Common WBE with primary well barrier.
3. Wellhead	5	Inclusive casing hanger, tubing hanger and access line with valves.
4. Tubing hanger	10	
5. Surface production tree	33	

Note
None

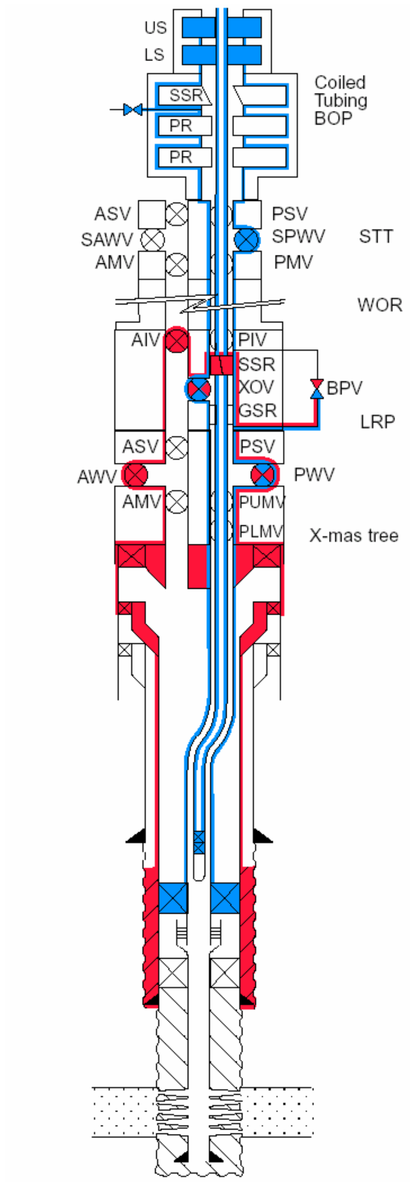
11.8.2 Running CT through surface production tree



Well barrier elements	See Table	Comments
Primary well barrier		
1. Casing cement	22	
2. Casing	2	Below production packer.
3. Production packer	7	
4. Completion string	25	
5. Tubing hanger	10	
6. Surface production tree	33	Inclusive kill and PWVs.
7. Coiled tubing safety head	16	Body
8. High pressure riser	26	
9. Coiled tubing BOP	14	Body w/kill valve.
10. Coiled tubing strippers	17	
11. Coiled tubing	13	Below stripper.
12. Coiled tubing check valves	15	
Secondary well barrier		
1. Casing cement	22	Common WBE with primary well barrier.
2. Casing	2	Part below production packer is a common WBE with primary well barrier.
3. Wellhead	5	Inclusive casing hanger and access line with valves.
4. Tubing hanger	10	Common WBE with primary well barrier.
5. Surface production tree	33	Common WBE with primary well barrier.
6. Coiled tubing safety head	16	Safety head body common WBE with primary well barrier.

Notes
Compensating measures for common WBEs can be:
1. A high pressure line shall be hooked up and leak tested for pumping kill fluid.
2. Sufficient fluid and materials available at the location to efficiently kill the well.

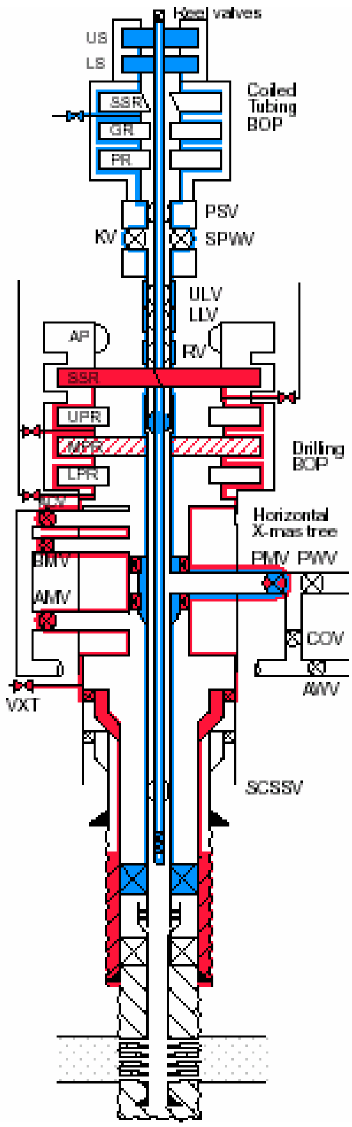
11.8.3 Running CT through vertical subsea production tree with LRP



Well barrier elements	See Table	Comments
Primary well barrier		
1. Casing cement	22	
2. Casing	2	Below production packer.
3. Production packer	7	
4. Completion string	25	
5. Wellhead	5	Inclusive tubing hanger and casing hanger.
6. Tuning hanger	10	
7. Subsea production tree	31	
8. Lower riser package	42	Connectors and body w/x-over valve and by-pass valve.
9. High pressure riser	26	
10. Surface test tree	34	Body and SPWV.
11. Coiled tubing BOP	14	Body w/kill valve.
12. Coiled tubing stripper	17	
13. Coiled tubing	13	Below stripper.
14. Coiled tubing check valves	15	
Secondary well barrier		
1. Casing cement	22	Common WBE with primary well barrier.
2. Casing	2	Part below production packer is a common WBE with primary well barrier.
3. Wellhead	5	Inclusive casing hanger and access line with valves is a common WBE with primary well barrier.
4. Tubing hanger	10	Common WBE with primary well barrier.
5. Subsea production tree	31	Common WBE with primary well barrier.
6. Lower riser package	42	LRP body, XOV and BPV common WBE with primary well barrier.

Notes
Compensating measures for common WBEs can be:
1. A high pressure line shall be hooked up and leak tested for pumping kill fluid.
2. Sufficient fluid and materials available at the location to efficiently kill the well.

11.8.4 Running CT through horizontal subsea Production tree with drilling BOP and SSTT



Well barrier elements	See Table	Comments
Primary well barrier		
1. Casing cement	22	
2. Casing	2	Below production packer.
3. Production packer	7	
4. Completion string	25	
5. Tubing hanger	10	
6. Subsea production tree	31	
7. Subsea test tree	32	
8. High pressure riser	26	Workover riser.
9. Surface test tree	34	Body and SPWV.
10. Coiled tubing BOP	14	Body w/kill valve.
11. Coiled tubing stripper	17	
12. Coiled tubing	13	Below stripper.
13. Coiled tubing check valves	15	
Secondary well barrier		
1. Casing cement	22	Common WBE with primary well barrier.
2. Casing	2	Part below production packer is a common WBE with primary well barrier.
3. Wellhead	5	Inclusive casing hanger and access line with valves.
4. Subsea production tree	31	Common WBE with primary well barrier.
5. Drilling BOP	4	Shear ram.

Notes

Compensating measures for common WBEs can be:

1. A high pressure line shall be hooked up and leak tested for pumping kill fluid.
2. Sufficient fluid and materials available at the location to efficiently kill the well.

12 Snubbing operations

12.1 General

This clause covers requirements and guidelines pertaining to well integrity during snubbing operations. Snubbing operations is a technique for deployment of tools and equipment by use of jointed pipe and as a conduit for circulating or placing fluids in the well. Snubbing string can be deployed in pressurised wells or in dead wells.

The purpose of this clause is to describe the establishment of well barriers by use of WBEs and additional features required to execute this activity in a safe manner.

See also Clause 13 for deployment of drilling and completion strings by use of drilling BOP and RCD in pressurised wells.

12.2 Well barrier schematics

It is recommended that WBSs are developed as a practical method to demonstrate and illustrate the presence of the defined primary and secondary barriers in the well, see 4.2. In the table below there are a number of typical scenarios listed, some of which are also attached as illustrations. The table is not comprehensive and schematics for the actual situations during an activity or operation should be made.

Item	Description	Comments	See
1.	Rigging snubbing equipment above production tree.		12.8.1
2.	Running tubular into dead well – shear ram able to shear.	Well not capable of flowing or hydrostatically killed.	
3.	Running tubular into dead well – unable to shear.	Well not capable of flowing or hydrostatically killed.	
4.	Running workstring into live well – shear ram able to shear.		12.8.2
5.	Running workstring into live well – unable to shear.	Non-shearable tools across shear ram or safety head.	

12.3 Well barrier acceptance criteria

The following requirements and guidelines apply:

a) The surface well control equipment for snubbing operation should consist of (top to bottom):

1) stripper bowl or active stripper;
2) dual stripper rams;
3) snubbing BOP and riser;
4) safety head (shear/seal ram).

b) All connections from the production tree to the top of the snubbing BOP shall be flanged or clamped and have metal-to-metal seals. Alternative connections and seals may be used when these are qualified.
c) Valve inlets or outlets in the surface well control rig-up shall be double with flanged or clamped connections. The inner valve shall be bi-directional with metal-to-metal seal in the bore. One of the two valves shall be remotely operated. Alternatively on inlets, the remote operated valve may be replaced by a manual valve and a check valve. The inner valve shall not be used as a working valve.
d) A pressure rated line shall be connected to the kill inlet of the well control rig-up.
e) A safety head shall be installed and leak tested prior to rigging up the snubbing well control equipment.
f) A method for monitoring of displacement volumes and maintaining the fluid level in the well shall be in place when deploying long BHA in an open well.
g) When deploying a long BHA that cannot be cut, a contingency joint and/or a system for dropping the BHA in the well shall be in place.

h) All tools or components that the safety head cannot cut shall be identified. Procedures for activation of the secondary well barrier when un-shear able tools or components are positioned across the safety head shall be described.
i) A wireline conveyed bridge plug for setting inside of the pipe being snubbed should be available
j) Minimum two pump down plugs for each "N" nipple profile size specified in the program shall be on location. Pump down plug assembly with pump open (circulation through) feature shall have internal metal-to-metal seal.
k) The length from the swab valve to upper stripper ram will normally be the WBE limit when defining the lubrication length.

12.4 Well barrier elements acceptance criteria

12.4.1 General

Subclause 12.8 lists the WBEs that constitute the primary and secondary barriers for situations that are illustrated.

12.4.2 Additional well barrier elements (WBEs) acceptance criteria

There are no additional acceptance criteria.

12.4.3 Common well barrier elements (WBEs)

A risk analysis shall be performed and risk reducing measures applied to reduce the risk as low as reasonable practicable, see 4.2.3.3. The following table describes risk reducing measures that can be applied when a WBE is an element in the primary and secondary well barrier:

WBS No.	Element name	Failure scenario	Probability reducing measures	Consequence reducing measures
Table 2	Casing (below production packer).	Leak through the body.	No requirements defined.	No requirements defined.
Table 22	Casing cement.	Break-down and leak through the cement.	No requirements defined.	No requirements defined.
Table 16	Snubbing safety head (body).	Leak through the body or connection seals.	Leak test prior to operation.	Kill fluid available for immediate use.
Table 31	Subsea production tree.	Leak through the body, outlet valves or connection seals.	Leak test prior to operation.	Kill fluid available for immediate use.
Table 33	Surface production tree.	Leak through the body, outlet valves or connection seals.	Leak test prior to operation.	Kill fluid available for immediate use.
Table 10	Tubing hanger.	Leak through the body.	Leak test prior to operation.	Kill fluid available for immediate use.

12.5 Well control action procedures and drills

12.5.1 Well control action procedures

The following table describes incident scenarios for which well control action procedures should be available (if applicable) to deal with the incidents should they occur. This list is not comprehensive and additional scenarios may be applied based on the actual planned activity, see 4.2.6.

Item	Description	Comments
1.	Unintentional shut down of main rig and auxiliary systems.	Fixed installation.
2.	Failure of power unit and loss of main hydraulic circuits.	Fixed installation.

Item	Description	Comments
3.	Slip bowl failure.	Fixed installation.
4.	Stripper rubber failure.	Fixed installation.
5.	Annular BOP leaking.	Fixed installation.
6.	Stripper BOP rams/active stripper leaking.	Fixed installation.
7.	Leak in upper pipe ram.	Fixed installation.
8.	Leak in lower pipe ram.	Fixed installation.
9.	Leak in shear/blind ram.	Fixed installation.
10.	Leak which can not be controlled by BOP stack.	Fixed installation.
11.	*Well control system* a) Unintentional closing of shear/blind or undersized ram. b) External leak in safety head withwork string above SSCSV if applicable. c) Work string below SSCSV. d) External leak below safety head. e) External leak while WL through the snubbing unit. f) Inside leak while wireline through snubbing pipe. g) Choke system failure.	Fixed installation.
12.	*Workstring* a) Inside blow-out. b) Intentional dropping of the workstring. c) Unintentional dropping of the workstring. d) Intentional shearing of the workstring. e) Parting of workstring. f) Buckling of workstring.	Fixed installation.
13.	*Lubrication of screens* a) Winch failure while MU or LD of screens. b) Leak in SSCSV. c) Leak in SSCSV – above point of no return. d) Unintentional dropping of screens.	Fixed installation.
14.	*Lubrication of guns* a) Leak in SSCSV. b) Unintentional dropping of guns. c) Power unit failure. d) Gun run – Surface deployment system.	Fixed installation.
15.	*Emergency situation on rig/ platform* a) Muster alarm general instructions. b) Abandon Alarm developing from muster alarm. c) Abandon alarm without muster alarm first.	Fixed installation.

12.5.2 Well control action drills

The following well control action drills should be performed:

Type	Frequency	Objective	Comments
See scenarios in 12.5.1	Once per week.	Response training.	The selected procedure shall be relevant for the ongoing operation.

12.6 Well design

There are no specific requirements or guidelines relating to well design.

12.7 Other topics

12.7.1 Hydrate prevention

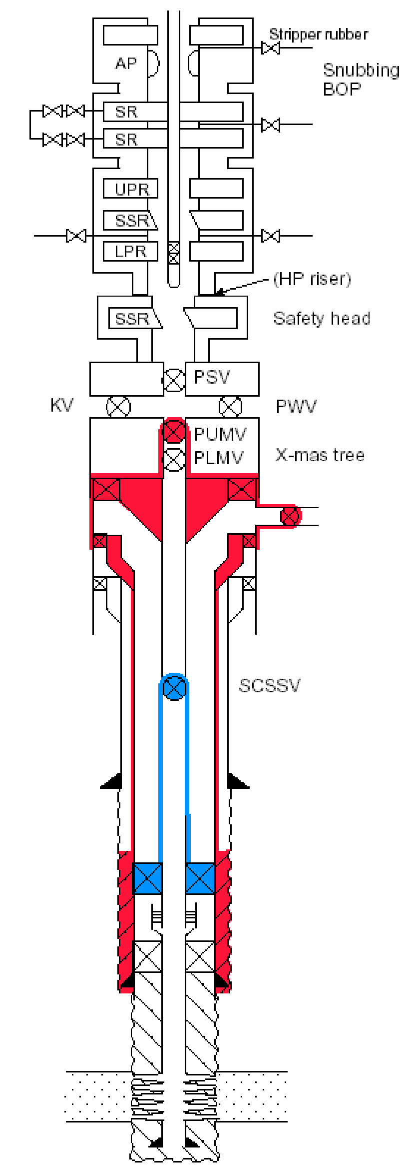
Hydrate-inhibited fluid shall be used when there is a risk for forming hydrates.

12.7.2 Snub/heavy force limitation

The operational limit value settings for the surface snubbing equipment with regards to torque, pull and push (snub and heavy force limit) shall be set based on the workstring and BHA mechanical properties and configuration.

12.8 Well barrier schematic illustrations

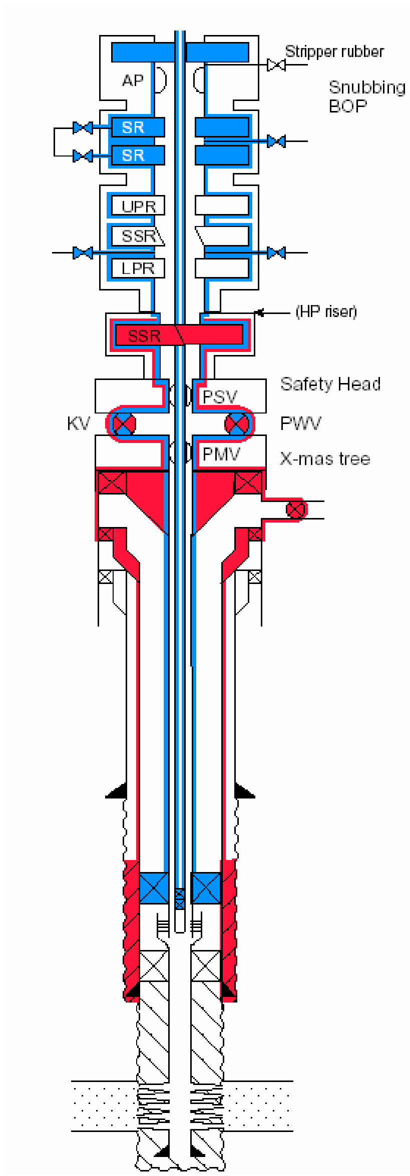
12.8.1 Rigging snubbing equipment above production tree



Well barrier elements	See Table	Comments
Primary well barrier		
1. Casing cement	22	
2. Casing	2	
3. Production packer	7	
4. Completion string	25	Below SCSSV.
5. SCSSV	8	
Secondary well barrier		
1. Casing cement	22	Common WBE with primary well barrier.
2. Casing	2	Common WBE with primary well barrier.
3. Wellhead	5	Inclusive casing hanger, tubing hanger and access line with valves.
4. Tubing hanger	10	
5. Surface production tree	33	

Note
None

12.8.2 Running workstring into live well – shear ram able to shear



Well barrier elements	See Table	Comments
Primary well barrier		
1. Casing cement	22	
2. Casing	2	Below production packer.
3. Production packer	7	
4. Completion string	25	
5. Tubing hanger	10	
6. Surface production tree	33	Inclusive kill and PWVs.
7. Snubbing safety head	21	Body
8. High pressure riser	26	
9. Snubbing BOP	19	Body w/kill and choke valve upper and lower stripper ram.
10. Snubbing strippers	20	
11. Snubbing string	30	Below stripper.
12. Snubbing check valves	18	
Secondary well barrier		
1. Casing cement	22	Common WBE with primary well barrier.
2. Casing	2	Part below production packer is a common WBE with primary well barrier.
3. Wellhead	5	Inclusive casing hanger, tubing hanger and access line with valves.
4. Tubing hanger	10	Common WBE with primary well barrier.
5. Surface production tree	33	Common WBE with primary well barrier.
6. Snubbing safety head	21	Safety head body common WBE with primary well barrier.

Notes
Compensating measures for common WBEs can be:
1. A high pressure line shall be hooked up and leak tested for pumping kill fluid.
2. Sufficient fluid and materials available at the location to efficiently kill the well.

13 Under balanced drilling and completion operations

13.1 General

This clause covers requirements and guidelines pertaining to well integrity during UBOs. This clause outlines recognized principles for UBD, LHD and UB completion operations using jointed pipe, which can be rotated at surface. Special adaptions should be made for the use of CT and hydraulic work over unit.

The purpose of this clause is to describe the establishment of well barriers by use of WBEs and additional features required to execute this activity in a safe manner.

Minimum requirements for barriers are defined for underbalanced operations with hydrocarbons produced to surface during drilling and completion activities. Other applications for underbalanced techniques should meet the same minimum requirements. Examples of this can be underbalanced drilling with no hydrocarbon production and low-head drilling with BHP close to balance.

See also Clause 5, Clause 7, Clause 11 and Clause 12.

13.2 Well barrier schematics

It is recommended that WBSs are developed as a practical method to demonstrate and illustrate the presence of the defined primary and secondary barriers in the well, see 4.2. In the table below there are a number of typical scenarios listed, some of which are also attached as illustrations. The table is not comprehensive and schematics for the actual situations during an activity or operation should be made.

Item	Description	Comment	See
1.	Drilling and tripping of work string in UB fluid.	RCD and drilling BOP installed, NRV in work string.	13.8.1
2.	Running and pulling completion in an UB fluid.	RCD and drilling BOP installed, NRV in completion string.	13.8.1
3.	Tripping work string using DIV.	DIV as part of primary well barrier.	13.8.2

13.3 Well barrier acceptance criteria

The following requirements and guidelines shall apply for UBD and UB completion operations:

a) Primary well control during underbalanced drilling is maintained by flow and pressure control. The BHP and the reservoir influx is monitored and controlled by means of a closed loop surface system including an RCD, flowline, ESDV, choke manifold and surface separation system:
   1) the RCD shall be installed above the drilling BOP and shall be capable of sealing the maximum expected wellhead circulating pressure against the rotating work string and containing the maximum expected shut-in wellhead pressure against a stationary work string;
   2) the return flowline shall have two valves, one of which shall be remotely operated and failsafe close (ESDV). The flowline and the valves shall have a WP equal to or greater than the anticipated shut-in wellhead pressure;
   3) a dedicated UBD choke manifold shall be used to control the flow rate and wellbore pressure, and reduce the pressure at surface to acceptable levels before entering the separation equipment. The choke manifold shall have a WP equal to or greater than the anticipated shut-in wellhead pressure. The choke manifold shall have two chokes and isolation valves for each choke and flow path. Applied surface backpressure should be kept to a minimum to reduce erosion of chokes and other surface equipment;
   4) a surface separation system shall be selected and dimensioned to handle the anticipated fluid/solids in the return flow. Plugging, erosion or wash-outs of surface equipment shall not impact the ability to maintain primary well control.

b) When running a work string UB, two NRVs, shall be installed in the string, as deep in the work string as practical and as close together as possible. The NRVs shall prevent wellbore fluids from entering into the work string. Installation of additional NRVs shall be considered depending on the nature of the operation (ie high-pressure gas). The NRV is a WBE and shall have a minimum WP rating equal to the maximum expected BHP.

c) Snubbing facilities shall be used or the well shall be killed with a kill weight fluid prior to tripping pipe, if the shut-in or flowing wellhead pressure can produce a pipe light condition and a DIV, a retrievable packer system or similar shut-in device, is not in use or is not functioning as designed.
d) Enough kill fluid of sufficient density shall be available on site at any time to be able to kill the well in an emergency. 1,5 times the hole volume should always be available.
e) A stab-in safety valve for the pipe in use shall be available on the rig floor.

13.4 Well barrier elements acceptance criteria

13.4.1 General

Subclause 13.8 lists the WBEs that constitute the primary and secondary barriers for situations that are illustrated.

13.4.2 Additional well barrier elements (WBEs) acceptance criteria

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

No.	Element name	Additional features, requirements and guidelines
Table 3	Drill pipe	For drilling high-pressure gas wells the connections shall prove to be gas tight and withstand the maximum expected internal and external pressures.
Table 4	Drilling BOP	BOPs are designed for secure, high-pressure containment for a low number of function cycles. The drilling BOP should be used as a secondary well barrier only, to minimize the number of cycles.

13.4.3 Common well barrier elements (WBEs)

A risk analysis shall be performed and risk reducing measures applied to reduce the risk as low as reasonable practicable, see 4.2.3.3. The following table describes risk reducing measures that can be applied when a WBE is an element in the primary and secondary well barrier:

No.	Element name	Failure scenario	Probability reducing measures	Consequence reducing measures
Table 22	Casing	Wearing a hole in the casing during drilling.	Measurement of casing thickness prior to and during of operations. Magnet in the flowline to measure metal. Conduct wear estimates during operations.	Continuous monitoring of "B"-annulus pressure. Kill fluid available for immediate use.
Table 2	Casing cement.	Leak through cement and up the annulus.	Pressure testing of cement to formation leak-off pressure. Assessment of cement bonding.	Continuous monitoring of "B"-annulus pressure. Kill fluid available for immediate use.
Table 4	Surface well control equipment.	Leak in surface well control equipment.	High quality certified equipment, periodic testing, preventative maintenance plan and solutions. Only manufacturers original equipment will be acceptable as replacement parts for use in safety critical equipment.	Have competent personnel involved in the operation. Kill fluid available for immediate use.
Table 5 Table 26 Table 4	Wellhead High pressure riser. Drilling BOP.	Leak in flanged connections below drilling BOP.	All bolts, studs and nuts in the stack especially on these connections shall be made up to manufacturers recommended torque with a proper makeup tool. Inspection for internal wear during installation and removal. Minimize number of flanges (ideally only one).	Monitoring for leaks with gas detection installed on specific connections. Kill fluid available for immediate use.

13.5 Well control action procedures and drills

13.5.1 Well control action procedures

The following table describes incident scenarios for which well control action procedures should be available (if applicable) to deal with the incidents should they occur. This list is not comprehensive and additional scenarios may be applied based on the actual planned activity, see 4.2.6.

Item	Description	Comment
1.	Bottom hole or surface pressure and/or flow rates detected which could lead to the pressure rating of the RCD (static or dynamic) or the capacity of the surface separation equipment being exceeded.	
2.	NRV failure, influx into work string during making connection or tripping in live well.	
3.	Leaking connection below drilling BOP.	
4.	Leaking RCD or flowline before ESDV.	Seal elements, connection to flowline, drilling BOP or high pressure riser.
5.	Erosion or wash out of choke.	Consider the case where isolation for

Item	Description	Comment
		repair of the choke cannot be achieved.
6.	Failure of surface equipment after RCD.	This can be leaks or plugged equipment and lines.
7.	Work string failure, washout or twist-off.	Consider pipe light scenario and contribution from additional NRVs in the drillstring.
8.	Emergency shut-in.	
9.	Emergency well kill.	
10.	Lost circulation.	
11.	H_2S in the well.	

13.5.2 Well control action drills

The following well control action drills should be performed:

Type	Frequency	Objective	Comment
Pressure rating of the RCD (static or dynamic) or the capacity of the surface separation equipment being exceeded.	Once per well with crew on tour.	Response training.	To be done prior to RIH.
Leaking NRV, influx into work string on making connection or tripping in live well.	Once per well with crew on tour.	Response training.	To be done prior to RIH.
Leak in RCD.	Once per well with crew on tour.	Response training.	To be done prior to RIH.
Leak in equipment after RCD.	Once per well with crew on tour.	Response training.	To be done prior to RIH.
Leak in drilling BOP lower connector.	Once per well with crew on tour.	Response training.	To be done prior to RIH.
Choke drill.	Once prior to starting UBD operations with crew on tour.	Practice in operating the power choke with pressure in the well.	Before drilling out of the last casing prior to UBD operation.
Uncontrolled work string movement out off well.	Once per well with crew on tour.	Response training.	To be done prior to RIH.
H_2S drills.	Prior to drilling into a potential H_2S zone/reservoir.	Practice in use of respiratory equipment.	All relevant personnel to have necessary training if H_2S is known to be present.

13.6 Under balanced drilling (UBD)

13.6.1 Under balanced drilling (UBD) fluid

The UBD fluid system can consist of basic liquids such as seawater, fresh water, brine, crude or base oil, occasionally combined with gas injection. Weighting material requirement depends on the reservoir pressure and the degree of draw down desired. The selected UBD fluid shall be suitable for the application it is chosen for.

13.6.2 Circulating system and flow simulations

The control of BHP and the design of a suitable circulation system is very important in UBD operations. In the planning and design phase of the project, multiphase flow modelling shall be done. The results of the modelling and other design parameters shall be used for equipment selection and in procedures prior to start of operations. Within these procedures the BHP operating envelope shall be set based on best available data. Optimal operating parameters for the execution phase shall be based on real time phase behaviour modelling and actual well and reservoir conditions.

Dynamic simulators should as a minimum be used to model the effects of starting and stopping circulation and the fluid interaction during connections.

13.7 Other topics

13.7.1 Under balanced drilling (UBD) procedures

UBD operations require procedures developed for the specific application of the method based on risk analysis and risk assessments. Procedures shall be developed for all critical activities. Amongst other, procedures should be developed for

- kicking off the well,
- making connections,
- live well tripping,
- erosion monitoring,
- trapped pressure in equipment,
- communication interfaces,
- change out of RCD rubber elements.

13.7.2 Personnel training

Competent personnel shall be used for UBD and completion operations. All personnel involved in the operation shall be trained in UBD operations, and the training shall be documented, i.e. UBO Rig Pass from International Association for Drilling Contractors (IADC). Personnel in the process of becoming competent shall be supervised by competent personnel.

13.7.3 Data acquisition

Relevant data shall be collected and displayed on screens on a continuous basis, including

- annulus/choke pressure,
- BHA,
- standpipe pressure,
- active surface system fluid volume,
- drilling fluid pump rate,
- returned gas rate,
- returned liquid rate,
- gas injection rate (if any),
- surface equipment pressure,
- surface and down hole temperature.

13.7.4 Surface separation system

Surface separation systems shall have documented relevant capability and suitability for the area they are to be located. Specifications of surface separation equipment (i.e. separators, sample catcher system, flare systems) and support systems are not included in this NORSOK standard.

13.7.5 Downhole Isolation valve

To facilitate normal RIH and pulling of the work string to surface and still maintain UB conditions in the open hole, a DIV can be installed in the casing string. The DIV may be qualified under certain operational conditions and limitations should be properly addressed during use.

When the work string is above the DIV, the valve can be closed, becoming part of the primary well barrier. A fluid column can be maintained above the valve.

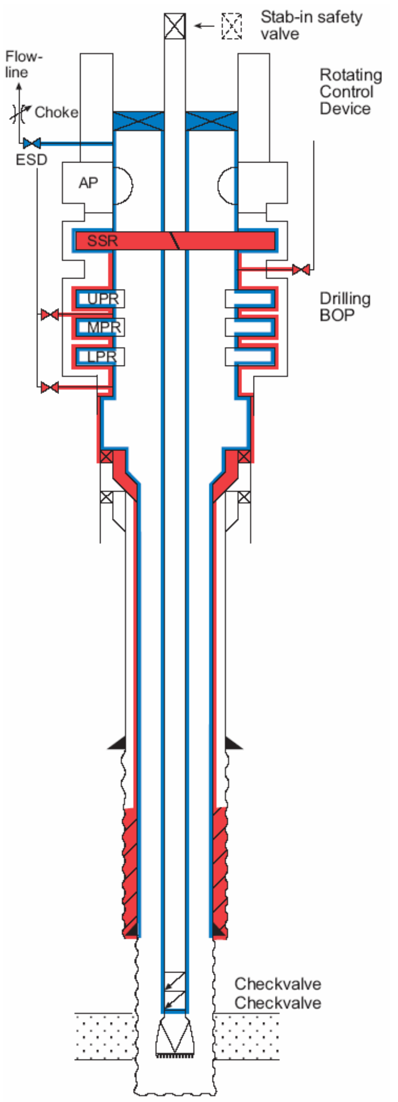
When the work string is below the open DIV, the RCD shall be in place as part of the primary well barrier.

13.7.6 Low head drilling

LHD is defined as UBD and, depending on complexity, uncertainty and risk exposure, should be performed using an RCD with flow line, debris catcher, choke manifold and fluid gas separator. This technique allows for maintaining a more or less constant BHP equal to or slightly above the formation pore pressure by adding static pressure at surface by manipulating the choke.

13.8 Well barrier schematic illustrations

13.8.1 Drilling and tripping of work string in UB fluid

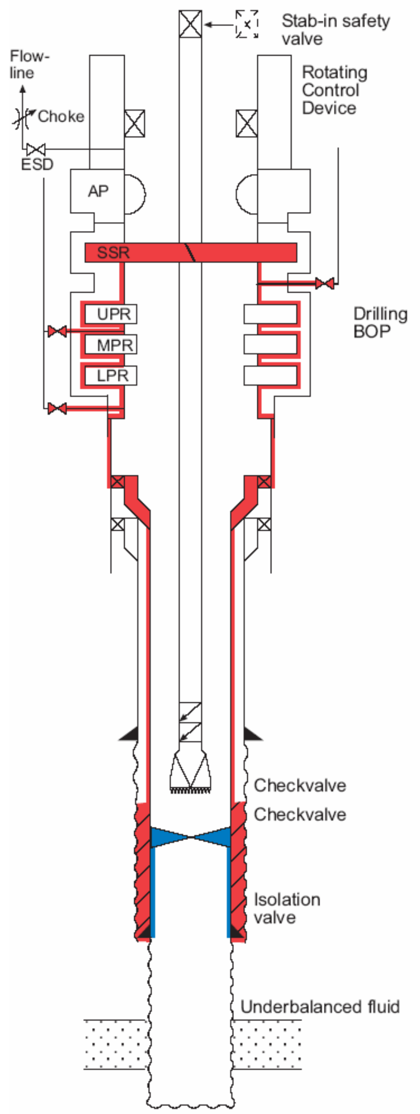


Well barrier elements	See Table	Comments
Primary well barrier		
1. Casing cement	22	
2. Casing	2	
3. Wellhead	5	
4. High pressure riser	26	
5. Drilling BOP	4	
6. Rotating control device	48	The flowline shall have two valves, one of which shall be remotely operated and failsafe close (ESDV).
7. Drilling non-return valves	50	
8. Drill string or completion string	3 25	Above NRV.
Secondary well barrier		
1. Casing cement	22	
2. Casing	2	
3. Wellhead	5	
4. High pressure riser	26	
5. Drilling BOP	4	Shear seal ram.

Notes

1. The well control configuration described is for rig-up on installations with a surface drilling BOP.
2. The work string refers to drill string (illustrated) or completion string.
3. Stab-in safety valve is readily available on the drill floor at all time with relevant connections.
4. Kill fluid to be readily available in order to perform an emergency kill.
5. For common WBEs, a risk analysis shall be performed and risk reducing/mitigation measures applied to reduce the risk as low as reasonable practicable.

13.8.2 Tripping workstring using DIV



Well barrier elements	See Table	Comments
Primary well barrier		
1. Casing cement	22	
2. Casing	2	
3. Downhole isolation valve	49	
Secondary well barrier		
1. Casing cement	22	Common WBE.
2. Casing	2	Below DIV: common WBE.
3. Wellhead	5	
4. High pressure riser	26	
5. Drilling BOP	4	Shear seal ram.

Notes

1. The well control configuration described is for rig-up on installations with a surface drilling BOP.2. The work string refers to drill string (illustrated) or completion string.
3. To facilitate normal RIH and pulling of the work string to surface and still maintain UB conditions in the open hole, a DIV can be installed in the previous casing. The DIV shall be tested and qualified as a WBE.
4. Stab-in safety valve is readily available on the drill floor at all time with relevant connections.
5. Kill fluid to be readily available in order to perform an emergency kill.

14 Pumping operations

14.1 General

This clause covers requirements and guidelines pertaining to well integrity during pumping (injection) of fluids into a well through tubing and annuli. The duration of the pumping operations might be short term, when performing stimulation, corrosion treatment, scale treatment, or long term, when disposing slurryfied drill cuttings or waste.

Continuous injection of water and gas or other fluids into reservoirs for enhanced oil recovery and reservoir pressure maintenance is covered in Clause 8. Cement pumping is not included.

The purpose of this clause is to describe the establishment of well barriers by use of WBEs and additional features required to execute this activity in a safe manner.

14.2 Well barrier schematics

It is recommended that WBSs are developed as a practical method to demonstrate and illustrate the presence of the defined primary and secondary barriers in the well, see 4.2. In the table below there are a number of typical scenarios listed, some of which are also attached as illustrations. The table is not comprehensive and schematics for the actual situations during an activity or operation should be made.

Item	Description	Comments	See
1.	Pumping operation - SCSSV isolated.		14.8.1
2.	Pumping - production tree isolation tool installed.		14.8.2
3.	Pumping fluids down the “A” annulus.		
4.	Pumping fluid down “B” annulus – No ASCCV installed.		14.8.3

14.3 Well barrier acceptance criteria

If the anticipated maximum pumping pressure exceeds the rated WP of the production tree, or a correspondingly lower pressure if production tree pressure rating has been reduced by corrosion or erosion, the production tree shall be isolated from the pumping pressure by a production tree isolation tool .

Injection shall not be performed into any formation which has the ability to

- propagate vertical fractures to the seabed,
- flow, unless there is a SCSSV installed in the tubing or a ASCSSV in the specific annulus used for injection, or if static hydrostatic pressure of the injected fluid column exceeds the pore pressure.

14.4 Well barrier elements acceptance criteria

14.4.1 Additional well barrier elements (WBEs) acceptance criteria

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

No.	Element name	Additional features, requirements and guidelines
Table 22	Casing cement.	Annulus or pipe bore below the injection point should be cemented and/or isolated to avoid injecting into a reservoir that is not intended for injection.
Table 33	Surface production tree.	Remotely actuated tree valves should be isolated from inadvertent closure during pumping operations.

14.4.2 Common well barrier elements (WBEs)

There is no defined risk reducing measures for common WBEs.

14.5 Well control action procedures and drills

14.5.1 Well control action procedures

The following table describes incident scenarios for which well control action procedures should be available (if applicable) to deal with the incidents should they occur. This list is not comprehensive and additional scenarios may be applied based on the actual planned activity, see 4.2.6.

Item	Description	Comments
1.	Leak in the production tree isolation tool during pumping operation.	
2.	Leak in the surface discharge lines.	How to close isolated production tree valves.

14.5.2 Well control action drills

Relevant well control action drills shall be performed before the operation commences with both shifts and thereafter once a week with both shifts.

14.6 Well design

14.6.1 General

See Clause 5 and Clause 7 for well design.

14.6.2 Design basis, premises and assumptions

It shall be verified that all well equipment and surface equipment can withstand the planned loads induced by the pumping operations. Historical operational data for the well shall be reviewed and the equipment pressure rating shall be downgraded as required based on measured or estimated material loss caused by corrosion, erosion and other factors that may have affected the integrity of the equipment.

14.6.3 Load cases

When designing for burst, collapse and axial load, the following load cases shall minimum be considered. This list is not comprehensive and actual cases based on the planned activity shall be performed.

Item	Description	Comments
1.	Material compatibility verification.	Material compatibility with all chemicals and mixtures of these chemicals which will be pumped.
2.	Maximum allowable pumping rate.	Assess abrasive erosion from all fluids and its content (sand, gravel etc) and pressure surge by accidental closure of a valve in the flow conduit when pumping at maximum allowable rate.
3.	Maximum expected differential pressure.	During the injection period.

14.6.4 Minimum design factors

See 5.6.4 and 7.6.4.

14.7 Other topics

14.7.1 Pumping through production tubing

The following applies when pumping through production tubing:

a) The SCSSV and HMV should be isolated from inadvertent closure during pumping operations.
b) Neighbour annulus and/or pipes isolated from the injection shall be monitored on a regular basis for pressure build up. The cause of any pressure increase (temperature, pipe expansion or leak) shall be verified.
c) After pumping, the pressure in the A annulus shall be monitored regularly until the temperature equilibrium is reached.

14.7.2 Handling and pumping of energised fluids

The following applies when handling or pumping liquefied gases or liquids containing gases:

a) All surface hoses and piping lines used on the low pressure side of the liquid gas shall be qualified for liquid gas service and the specific gas to be pumped.
b) It should be possible to drain the lowest point of surface hoses and piping lines to minimise the risk of having ice blocks.
c) All equipment used for storing and/or pumping liquefied gases shall be positioned in a bounded area.
d) The bounded area shall
   1) be arranged to collect and contain accidental spills of liquefied gases;
   2) provide thermal insulation of deck and construction;
   3) have water hoses with fine spray nozzle available .
e) The discharge line should have a one-way check valve and pressure bleed-off arrangement.
f) Rubber hoses should not be used as a part of the high pressure discharge line.
g) The injection pump shall be fitted with a pressure limit switch, which shall be set to 1,1 times the maximum allowable pumping pressure.

14.7.3 Temporary installed surface discharge lines

When temporarily installed surface discharge lines are used in conjunction with pumping operations, the following applies:

a) They shall be adequately anchored to prevent whipping, bouncing, or excess vibration, and to constrain all piping if a break should occur.
b) Precautions shall be taken and reviewed with relevant personnel to ensure that they are not damaged by dropped objects from cranes, trolleys, skidding systems etc.
c) Their WP shall be equal to or exceed the maximum expected pumping pressure and should not be less than 34,5 MPa.
d) They shall be leak tested to a pressure exceeding maximum allowable pumping pressure, after installation and prior to use.
e) They should have sufficient ID to avoid erosion from the pumping operation.
f) A check valve shall be installed in each discharge line as close to the connection point as possible. A bleed-off line between the check valve(s) and the production tree master valve should be installed to enable venting of trapped pressure.
g) They shall be equipped with a pressure relief valve set and checked for the maximum allowable pumping pressure. The relief valve should discharge into a non-hazardous location.

14.7.4 Hard piping discharge lines

There are no additional requirements and guidelines to what is stated in 14.7.3.

14.7.5 Flexible hose discharge lines

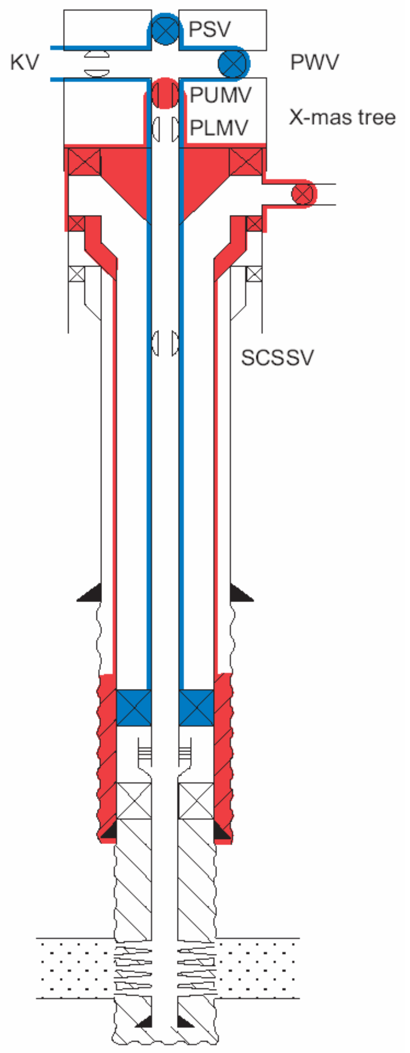
Flexible hoses are rubber or steel wrapped rubber hoses (hoses with thermoplastic inner liner/tube are not covered).

Additionally to what is stated in 14.7.3, the following applies:

a) Flexible hoses should not be used when expected pumping pressure exceeds 34,5 MPa.
b) Flexible hoses should only be exposed to water based fluids.
c) The WP shall be minimum 34,5 MPa and the design burst pressure shall be four times the WP.
d) The inner surface of the flexible hose should be neoprene rubber which is not corrosive to HCl.
e) The construction of the external armor should be banded stainless steel rather that braided.
f) Integral end fittings should be used.
g) Minimum bend radius shall be verified for the specific flexible hose in use.

14.8 Well barrier schematics illustrations

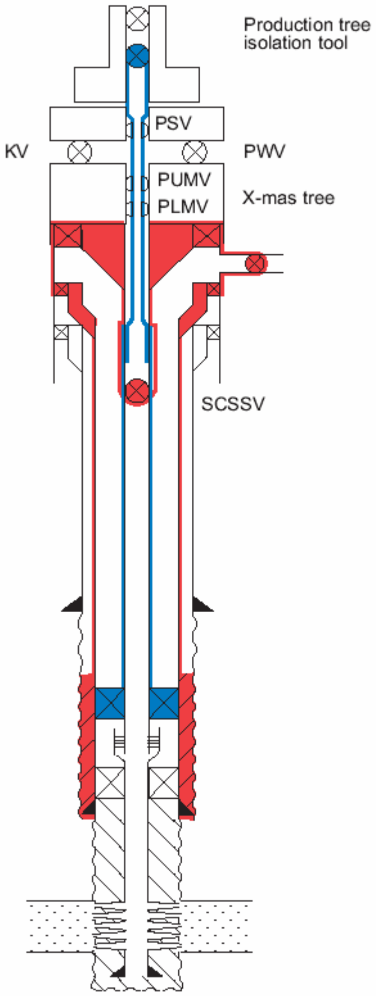
14.8.1 Pumping trough tubing - SCSSV isolated



Well barrier elements	See Table	Comments
Primary well barrier		
1. Production packer	7	
2. Completion string	22	Between tubing hanger and production packer.
3. Tubing hanger	10	
4. Surface production tree	33	Kill valve closed.
Secondary well barrier		
1. Casing cement	22	
2. Casing	2	
3. Wellhead	5	
4. Tubing hanger	10	
5. Surface production tree	33	Production upper master valve closed.

Note
None

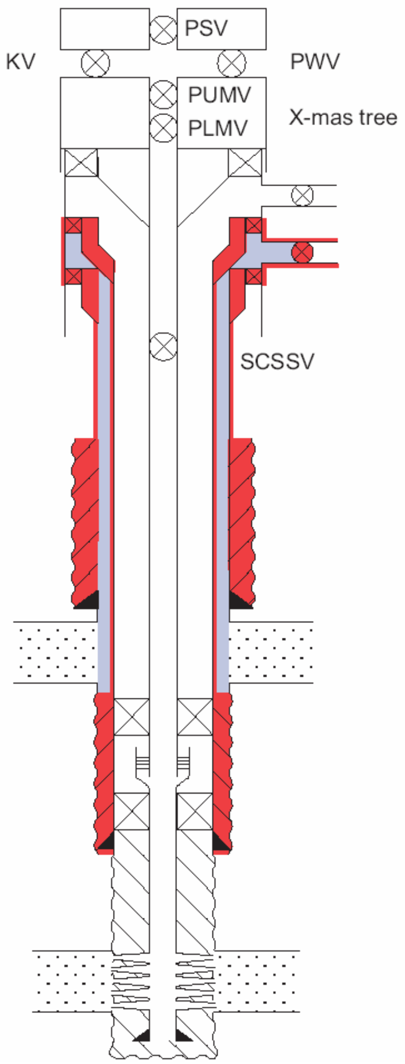
14.8.2 Pumping trough tubing - Production tree isolation tool installed



Well barrier elements	See Table	Comments
Primary well barrier		
1. Production packer	7	
2. Completion string	22	Between production tree isolation tool stinger and production packer.
3. Production tree isolation tool	23	
Secondary well barrier		
1. Casing cement	22	
2. Casing	2	
3. Wellhead	5	
4. Tubing hanger	10	
5. Completion string	22	Between tubing hanger and SCSSV.
6. SCSSV	8	

Note
None

14.8.3 Pumping fluid down "B" annulus – No ASCCV installed



Well barrier elements	See Table	Comments
Primary well barrier		
1. Fluid column	1	Applies to the injected zone.
Secondary well barrier		
1. Casing cement	22	Applies to the lower zone.
2. Casing	2	Production casing. Applies to the injected zone.
3. Wellhead	5	Applies to the injected zone.
4. Casing	2	Intermediate casing. Applies to the injected zone.
5. Casing cement	22	Intermediate casing shoe. Applies to the injected zone.

Note
None

15 Well barrier elements acceptance tables

15.1 Table 1 – Fluid column

Features	Acceptance criteria	See
A. Description	This is the fluid in the well bore.	NORSOK D-001
B. Function	The purpose of the fluid column as a well barrier/WBE is to exert a hydrostatic pressure in the well bore that will prevent well influx/inflow (kick) of formation fluid.	
C. Design construction selection	1. The hydrostatic pressure shall at all times be equal to the estimated or measured pore/reservoir pressure, plus a defined safety margin (e.g. riser margin, trip margin). 2. Critical fluid properties and specifications shall be described prior to any operation. 3. The density shall be stable within specified tolerances under down hole conditions for a specified period of time when no circulation is performed. 4. The hydrostatic pressure should not exceed the formation fracture pressure in the open hole including a safety margin or as defined by the kick margin. 5. Changes in well bore pressure caused by tripping (surge and swab) and circulation of fluid (ECD) should be estimated and included in the above safety margins.	ISO 10416
D. Initial test and verification	1. Stable fluid level shall be verified. *2.* Critical fluid properties, including density shall be within specifications.	
E. Use	1. It shall at all times be possible to maintain the fluid level in the well through circulation or by filling. 2. It shall be possible to adjust critical fluid properties to maintain or modify specifications. 3. Acceptable static and dynamic loss rates of fluid to the formation shall be pre-defined. 4. There should be sufficient fluid materials, including contingency materials available on the location to maintain the fluid well barrier with the minimum acceptable density.	
F. Monitoring	1. Fluid level in the well and active pits shall be monitored continuously. 2. Fluid return rate from the well shall be monitored continuously. 3. Flow checks should be performed upon indications of increased return rate, increased volume in surface pits, increased gas content, flow on connections or at specified regular intervals. The flow check should last for 10 min. HTHP: All flow checks should last 30 min. 4. Measurement of fluid density (in/out) during circulation shall be performed regularly. 5. Measurement of critical fluid properties shall be performed every 12 circulating hours and compared with specified properties. 6. Parameters required for killing of the well .	ISO 10414-1 ISO 10414-2
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Flow of formation fluids.	

15.2 Table 2 – Casing

Features	Acceptance criteria	See
A. Description	This element consists of casing/liner and/or tubing in case tubing is used for through tubing drilling and completion operations.	
B. Function	The purpose of casing/liner is to provide a physical hindrance to uncontrolled flow of formation fluid or injected fluid between the bore and the back-side of the casing.	
C. Design construction selection	1. Casing-/liner strings, including connections shall be designed to withstand all pressures and loads that can be expected during the lifetime of the well including design factors. 2. Minimum acceptable design factors shall be defined for each load type. Estimated effects of temperature, corrosion and wear shall be included in the design factors. 3. Dimensioning load cases with regards to burst, collapse and tension/compression shall be defined and documented. 4. Casing design can be based on deterministic, probabilistic or other acceptable models.	ISO 11960 API Bull 5C3 API Bull 5C2
D. Initial test and verification	1. Casing/liner shall be leak tested to maximum anticipated differential pressure. 2. Casing/liner that has been drilled through after initial leak test shall be retested during completion activities.	
E. Use	1. Casing/liner should be stored and handled to prevent damage to pipe body and connections prior to installation.	ISO 10405 API Bull 5C2
F. Monitoring	1. The A annulus shall be continuously monitored for pressure anomalies. Other accessible annuli shall, if applicable be monitored at regular intervals. 2. If wear conditions exceed the assumptions from the casing-/liner design, indirect or direct wear assessment should be applied (e.g. collection of metal shavings by use of ditch magnets and wear logs).	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leaking casing/liner.	

15.3 Table 3 – Drill string

Features	Acceptance criteria	See
A. Description	This element consists of drill pipe, heavy weight drill pipe and drill collars used as drill string or work string.	
B. Function	The purpose of the drill string as WBE is to prevent flow of formation fluid from its bore and to the external environment.	
C. Design construction selection	1. Dimensioning load cases shall be defined and documented. 2. Minimum acceptable design factors shall be defined. Estimated effects of temperature, corrosion, wear; fatigue and buckling shall be included in the design factors. 3. Drill pipe should be selected with respect to • make-up torque necessary to prevent make-up in the well, • tool joint clearance and fishing restrictions, • pumping pressure and ECD, • abrasive formations, • buckling resistance, • hard banding and its influence on casing wear, • metallurgical composition in relation to exposure tocorrosive environment, • fatigue resistance, • HPHT: Strength reduction due to temperatures effects.	API Spec. 7 ISO 11961 API Bull 5C2
D. Initial test and verification	1. Stable pump pressure when circulating fluid. 2. HPHT: The component of the drill string should be MPI inspected prior to HPHT mode status.	
E. Use	1. Stab-in safety valve and one way check valve for all type of connections exposed at the drill floor shall be readily available when the drill string is located inside the BOP. 2. Drilling float valves should be installed in the drill string.	API RP 7G
F. Monitoring	1. Pump pressure shall be continuously monitored for pressure anomalies during circulation. 2. Regular inspection and maintenance based on documented routines shall be conducted. 3. Visual checks for wear, washouts, thread damage and cracks should be conducted regularly.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leaking through drill string (“wash out”). 2. Exposure to H_2S (if not designed for it). 3. Inability to document material certificate.	

15.4 Table 4 - Drilling BOP

Features	Acceptance criteria	See
A. Description	The element consists of the wellhead connector and drilling BOP with kill/choke line valves.	NORSOK D-001
B. Function	The function of wellhead connector is to prevent flow from the bore to the environment and to provide a mechanical connection between drilling BOP and the wellhead. The function of the BOP is to provide capabilities to close in and seal the well bore with or without tools/equipment through the BOP.	
C. Design construction selection	1. The drilling BOP shall be constructed in accordance with NORSOK D-001. 2. The BOP WP shall exceed the MWDP including a margin for killing operations. 3. It shall be documented that the shear/seal ram can shear the drill pipe, tubing, wireline, CT or other specified tools, and seal the well bore thereafter. If this can not be documented by the manufacturer, a qualification test shall be performed and documented. 4. When running non shearable items, there shall be minimum one pipe ram or annular preventer able to seal the actual size of the non shearable item. 5. For floaters the wellhead connector shall be equipped with a secondary release feature allowing release with ROV. 6. When using tapered drill pipe string there should be pipe rams to fit each pipe size. Variable bore rams should have sufficient hang off load capacity. 7. There shall be an outlet below the LPR. This outlet shall be used as the last resort to regain well control in a well control situation. 8. HTHP: The BOP shall be furnished with surface readout pressure and temperature. 9. Deep water: 9.1. The BOP should be furnished with surface readout pressure and temperature. 9.2. The drilling BOP shall have two annular preventers. One or both of the annular preventers shall be part of the LMRP. It should be possible to bleed off gas trapped between the preventers in a controlled way. 9.3. Bending loads on the BOP flanges and connector shall be verified to withstand maximum bending loads (e.g. highest allowable riser angle and highest expected drilling fluid density.) 9.4 From a DP vessel it shall be possible to shear full casing strings and seal thereafter. If this is not possible the casings should be run as liners.	NORSOK D-001 API RP 53
D. Initial test and verification	See Annex A, Table A.1.	
E. Use	The drilling BOP elements shall be activated as described in the well control action procedures.	
F. Monitoring	See Annex A, Table A.1.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. See Annex A, Table A.2.	

15.5 Table 5 – Wellhead

Features	Acceptance criteria	See
A. Description	The element consists of the wellhead body with annulus access ports and valves, seals and casing/tubing hangers with seal assemblies.	
B. Function	Its function is to provide mechanical support for the suspending casing and tubing strings and for hook-up of risers or BOP or production tree and to prevent flow from the bore and annuli to formation or the environment.	
C. Design construction selection	1. The WP for each section of the wellhead shall exceed the maximum anticipated well shut in pressure the section can become exposed to plus a defined safety factor. 2. For dry wellheads, there shall be access ports to all annuli to facilitate monitoring of annuli pressures and injection/bleed-off of fluids. 3. For subsea wellheads, there shall be access to the casing by tubing annulus to facilitate monitoring of annulus pressure and injection /bleed-off of fluids. 4. Wellheads that will be used as a flow conduit for continuous or intermittent production from or injection into annulus/annuli, shall be designed and qualified for such functions without impairing the well integrity function of the wellhead. For gas lift applications, gas expansion and the resulting temperature should be addressed.	ISO 10423
D. Initial test and verification	1. The wellhead body (or bodies and seals), annulus ports with valves and the casing or tubing seal assemblies shall be leak tested to maximum expected shut in pressure for the specific hole section or operation.	
E. Use	1. A wear bushing should be installed in the wellhead whenever movement of tools/work-strings can inflict damage to seal areas.	
F. Monitoring	1. Annuli wing valves shall be pressure and function tested frequently. 2. The A annulus shall be continuously monitored for pressure anomalies. Other accessible annuli shall, if applicable be monitored at regular intervals. 3. Movements in the wellhead during work over (shut-in/start-up) should be observed and compared to design values.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leaking seals or valves.	

15.6 Table 6 – Deep set tubing plug

Features	Acceptance criteria	See
A. Description	This element consists of an equalising body with a locking or anchoring device and a seal between the bore of the tubing and the body of the plug.	
B. Function	Its purpose is to provide a temporary seal in the bore to prevent flow from the reservoir and up the tubing.	
C. Design, construction and selection	1. It shall comply with same requirements that apply to packers (ISO testing/envelope description).	ISO 14310
D. Initial test and verification	1. It shall by preference be leak tested to the maximum expected differential pressure in the direction of flow. 2. Alternatively, it shall be inflow tested or leak tested in the opposite direction to the maximum expected differential pressure, providing that ability to seal both directions can be documented.	
E. Use	1. It shall be set at a depth that allows balancing of the pressure under the plug with a hydrostatic fluid column above the plug. (not to exceed the maximum fluid density the rig can handle)	
F. Monitoring	1. The tubing pressure above the plug should be monitored regularly if access is available. If unavailable by closure of additional well barrier, awareness of pressure need to be taken when opening the additional well barrier.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Inability to pass pressure testing or monitoring requirements.	

15.7 Table 7 – Production packer

Features	Acceptance criteria	See
A. Description	This is element consists of a body with an anchoring mechanism to the casing/liner, and an annular sealing element which is to be activated.	
B. Function	Its purpose is to provide 1. A seal between the completion string and the casing/liner, to prevent communication from the formation into the A-annulus above the production packer. 2. Prevent flow from the inside of the body element located above the packer element into the A-annulus as part of the completion string.	
C. Design, construction and selection	1. It shall as a minimum be tested to V1 class as per ISO 14310. 2. It shall be permanently set (meaning that it shall not release by up or downward forces), with ability to sustain all known loads. 3. It might be retrievable by mechanical intervention, such features shall not be possible to accidentally activate. 4. The packer (body and seal element) shall withstand MEDP, which should be based on the highest of • pressure testing of tubing hanger seals, • reservoir-, formation fracture- or injection pressures less hydrostatic pressure of fluid in annulus above the packer, • shut-in tubing pressure plus hydrostatic pressure of fluid in annulus above the packer less reservoir pressure, • collapse pressure as a function of minimum tubing pressure (plugged perforations or low test separator pressure) at the same time as a high operating annulus (maximum allowable) pressure is present. 5. It shall be qualification tested in accordance with recognized standards, which shall be conducted in unsupported, non cemented, standard casing.	ISO 14310
D. Initial test and verification	1. It shall by preference be leak tested to the maximum expected differential pressure in the direction of flow. 2. Alternatively, it shall be inflow tested or leak tested in the opposite direction to the maximum expected differential pressure, providing that ability to seal both directions can be documented.	
E. Use	1. Running of intervention tools shall not impair its ability to seal nor inadvertedly cause it to be released.	
F. Monitoring	1. Sealing performance shall be monitored through continuous recording of the annulus pressure measured at wellhead level.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Inability to maintain a pressure seal.	

15.8 Table 8 – Surface controlled sub-surface safety valve

Features	Acceptance criteria	See
A. Description	This element consists of a tubular body with a close/open mechanism that seals off the tubing bore.	
B. Function	Its purpose is to prevent flow of hydrocarbons or fluid up the tubing.	
C. Design, construction and selection	1. It shall be positioned minimum 50 m below seabed. 2. The setting depth shall be dictated by the pressure and temperature conditions in the well with regards to forming of hydrates and deposition of wax and scale. 3. It shall be • surface controlled, • automatically operated, • hydraulically operated, • fail-safe closed, 4. It should be placed below the well kick-off point in order to provide well shut-in capabilities below a potential collision point. 5. The fail-safe closing function (maximum setting depth) should be calculated based on the highest density of fluids in the annulus.	API RP14B
D. Initial test and verification	1. It shall be tested with both low and high differential pressure in the direction of flow. The low pressure test shall be maximum 7 MPa.	
E. Use	1. When exposed to high velocities or abrasive fluid, increased testing frequency shall be considered.	
F. Monitoring	1. The valve shall be leak tested at specified regular intervals as follows: • test duration shall be 30 min, • monthly, until three consecutive qualified tests have been performed, thereafter - • every three months, until three consecutive qualified tests have been performed, thereafter - • every six months. 2. Acceptance of downhole safety valve tests shall meet API RP 14B requirements being • 0,42 Sm^3/min (25,5 Sm^3/hr) (900 scf/hr) for gas, • 0,4 l/min (6,3 gal/hr) for liquid. 3. If the leak rate cannot be measured directly, indirect measurement by pressure monitoring of an enclosed volume downstream of the valve shall be performed. 4. If the leakrate exceeds the accept criteria, the test can be attempted three times to verify the valve status. If the accept criteria is still not meet, further investigation and remedial action shall be undertaken, consider involving the drilling/well operations department.	API RP 14B ISO 10417
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Failure to pass the regular test intervals and maximum allowable leak rate.	

15.9 Table 9 – Annulus surface controlled sub-surface safety valve

Features	Acceptance criteria	See
A. Description	This is element consist of a body, an annulus sealing element which can be activated and control lines.	
B. Function	Its purpose is to • prevent flow of hydrocarbons or fluid up the annulus, • provide a pressure seal between the bore and the A-annulus.	
C. Design, construction and selection	1. It shall be designed and tested in accordance with API RP14B. 2. It shall be located minimum 50 m below seabed. If annulus is used for production, the setting depth shall be determined by the possibility of forming of hydrates and deposition of wax and scale. 3. It shall be subject to flow erosion resistance verification for all relevant fluids, if it will become exposed to high production/injection rates. 4. It shall be, when part of the annulus safety system, comply with the same requirements as for production packer (ISO testing/envelope description). 5. It shall have a WP which exceeds the MEDP. The MEDP should be based on reservoir pressure less gas gradient below packer and evacuated A-annulus above.	API RP 14B ISO 14310
D. Initial test and verification	It shall be leak tested in the direction of flow to 1. a low pressure which shall maximum be 7 MPa, 2. MEDP.	
E. Use	1. When exposed to high velocities or abrasive fluid, increased testing frequency shall be considered.	
F. Monitoring	1. The valve shall be leak tested at specified regular intervals as follows: • test duration shall be 30 min, • monthly, until three consecutive qualified tests have been performed, thereafter - • every three months, until three consecutive qualified tests have been performed, thereafter - • every six months 2. Acceptance of downhole safety valve tests shall meet API RP 4B requirements being • 0,42 Sm^3/min (25,5 Sm^3/hr) (900 scf/hr) for gas, • 0,4 l/min (6,3 gal/hr) for liquid. 3. If the leak rate can not be measured directly, indirect measurement by pressure monitoring of an enclosed volume downstream of the valve shall be performed. 4. If the leakrate exceeds the accept criteria, the test can be attempted three times to verify the valve status. If the accept criteria is still not meet, further investigation and remedial action shall be undertaken.	API RP 14B ISO 10417
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Failure to pass the regular test intervals and maximum allowable leak rate.	

15.10 Table 10 – Tubing hanger

Features	Acceptance criteria	See
A. Description	This element is consists of body, seals and a bore which may have a tubing hanger plug profile.	
B. Function	Its function is to • support the weight of the tubing, • prevent flow from the bore and to the annulus, • provide a seal in annulus space between the itself and the wellhead, • provide a stab-in connection point for bore communication with the production tree. • provide a profile to receive a BPV or plug to be used for nippling down the BOP and nippling up the production tree.	
C. Design, construction and selection	1. Shall be designed and fabricated according to ISO 13533 2. When used in conjunction with annulus injection (gas lift, cutting injection, etc.) any low temperature cycling effects need to be taken into consideration.	ISO 13533
D. Initial test and verification	1. The primary seal shall be tested in the flow direction. 2. The hanger seal can be tested against the flow direction. 3. If only single seals are used in the tubing hanger, annulus is to be tested. In the case of double seal, an in-between seal test might be performed.	
E. Use	1. None.	
F. Monitoring	1. Continuous monitoring of annulus pressure.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leak past seals.	

15.11 Table 11 – Tubing hanger plug

Features	Acceptance criteria	See
A. Description	This element consists of an equalising plug with a locking device and a seal between the bore of the tubing hanger and the body of the plug.	
B. Function	Its function is to • provide a pressure well barrier in the bore through the tubing hanger, • facilitate a well barrier plug during BOP/production tree removal and installation.	
C. Design, construction and selection	1. It shall only be classified as a WBE during BOP or production tree disconnect, providing the plug (and prong) does not extend up above the tubing hanger body.	
D. Initial test and verification	1. The tubing hanger plug shall be tested in the flow direction. When this is not possible, it should be tested from above 2. The tubing hanger plug shall be tested to maximum expected differential pressure	
E. Use	None.	
F. Monitoring	1. Regular monitoring of pressure above plug or by visual observation.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Non-compliance with above mentioned requirements.	

15.12 Table 12 – Well Head/Annulus access valve

Features	Acceptance criteria	See
A. Description	This is element consists of the wellhead housing and an isolation valve.	
B. Function	Its function is to provide ability to monitor pressure and flow to the A-annulus below the tubing hanger.	
C. Design, construction and selection	1. The housing shall have a material grade and specification compatible with the materials of which it is attached to. 2. The housing and valve(s) shall be fire resistant. 3. The valve shall be gas tight. 4. The access point and valve shall have a pressure rating equal to or higher than the wellhead/production tree system. 5. When used in conjunction with annulus injection (gas lift, cuttings injection, etc.) any low temperature cycling effects need to be taken into consideration.	
D. Initial test and verification	The valve shall be tested in the direction annulus to process piping.	
E. Use	1. The valve shall normally be open for monitoring purposes, with another valve isolating the access to the platform system, which should only be opened for the purpose of adjusting the annulus pressure.	
F. Monitoring	1. Sealing performance shall be monitored through continuous recording of the annulus pressure measured at wellhead level.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Inability to maintain a pressure seal. 2. Seeping or sweating valve surface.	

15.13 Table 13 – Coiled tubing

Features	Acceptance criteria	See
A. Description	This element consists of a continuous milled tubing string that is spooled on to a CT reel.	
B. Function	The function of the CT string as a WBE is to prevent flow of formation fluid from its bore to the external environment.	
C. Design, construction and selection	1. Dimensioning load cases shall be defined and documented. 2. Minimum acceptable design factors shall be defined (80 % of minimum yield). Estimated effects of temperature, corrosion, wear, fatigue and buckling shall be included in the design factors. 3. Coiled tubing should be selected with respect to • yield strength, • pump rate, • length, • weight, • burst pressure, • collapse pressure.	API RP 5C7
D. Initial test and verification	1. Leak test after initial rig-up. 2. Leak test to maximum expected WHP on following runs.	
E. Use	1. An end-connector with a double/dual check valve assembly or a fail-safe closing device to prevent unintentional flow of formation fluid into the CT string shall be used.	
F. Monitoring	1. Pump pressure and wellhead pressure shall be continuously monitored during the operation. 2. Regular inspection and maintenance based on documented routines shall be conducted. 3. Visual or continuous inspection during operation.	NORSOK D-002
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leaking through CT string and the CT check valves are not holding pressure. 2. Changes or damage to the CT geometry preventing the stripper to maintain a pressure seal.	

15.14 Table 14 – Coiled tubing BOP

Features	Acceptance criteria	See
A. Description	This element consists of a BOP body with rams, a kill inlet connection and riser connections.	NORSOK D-002
B. Function	The function of the CT BOP is to prevent flow form the well bore in case of leakage in the CT string or stripper. It shall be able to close in and seal the well bore with or without the CT string through the BOP. The CT BOP is a back-up WBE to the stripper in the primary well barrier.	
C. Design, construction and selection	1. The CT BOP shall be designed in accordance with NORSOK D-002. 2. The pressure rating shall exceed the maximum expected differential pressure that it can become exposed to, including a margin for killing operations. 3. It shall be documented that the shear/seal ram can shear the CT and seal off the wellbore thereafter. If this cannot be documented by the manufacturer, a qualification test shall be performed and documented. 4. The pipe ram shall be able to provide a seal on the CT annulus. 5. The slip ram shall be able to grip and hold the CT string. 6. A kill inlet port shall be located between the shear/seal ram and the pipe ram. It shall be possible to pump heavy fluid through the CT string after the BOP has been activated.	NORSOK D-002 ISO 13533 ISO 15156-1 API RP 5C7
D. Initial test and verification	1. Function test after initial installation. 2. Perform low- and high pressure leak tests after initial installation. 3. Leak test connections where seals have been de-energised to maximum expected WHP on following runs.	
E. Use	1. The CT BOP elements shall be activated as described in the well control action procedures (contingency procedures need to be established by the user).	
F. Monitoring	1. Periodic visual inspection for external leaks. 2. Periodic leak- and functional test, minimum each 14 d.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leak in any of the elements, body or connections. 2. Unable to operate or malfunction.	

15.15 Table 15 – Coiled tubing check valves

Features	Acceptance criteria	See
A. Description	This element consists of a body with a double/dual flapper check valve or a failsafe closing device and a connector for mounting to the end of the CT string.	
B. Function	The function of the CT check valves are to prevent unintentional flow of formation fluid into the CT string.	
C. Design, construction and selection	1. The check valves shall be designed to withstand all expected downhole forces and conditions. 2. The pressure rating shall exceed the maximum operating pressure. 3. The check valves shall be provided with dual seals in the bore and provide internal and external sealing on the connections towards the CT string. 4. Provisions shall be made for pumping balls through the CT check valves.	NORSOK D-002
D. Initial test and verification	1. Leak test prior to connecting to the CT string. 2. Inflow test prior to each run in hole.	
E. Use	1. The end-connector and CT check valves are connected directly to the end of the CT string.	
F. Monitoring	1. Periodic inflow test.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leakage through the check valves.	

15.16 Table 16 – Coiled tubing safety head

Features	Acceptance criteria	See
A. Description	This element consists of a BOP body with a shear/seal ram and riser connections.	
B. Function	The function of the CT safety head (BOP) is to prevent flow from the well bore in case of loss or leakage in the primary well barrier at the surface. It shall be able to close in and seal the well bore with or without CT through the BOP. The safety head is the upper closure device in the secondary well barrier.	
C. Design, construction and selection	1. The CT safety head shall be designed in accordance with NORSOK D-002. 2. The pressure rating shall exceed the maximum expected differential pressure that it can become exposed to, including a margin for killing operations. 3. It shall be documented that the shear/seal ram can shear the CT or wireline and seal the wellbore thereafter. If this cannot be documented by the manufacturer, a qualification test shall be performed and documented.	NORSOK D-002 ISO 13533 ISO 15156-1 API RP 5C7
D. Initial test and verification	1. Function test after initial installation. 2. Perform low- and high pressure leak tests after initial installation. 3. Leak test connections where seals have been de-energised to maximum expected WHP on following runs.	
E. Use	1. The CT safety head shall be activated as described in the well control action procedures (contingency procedures need to be established by the user).	
F. Monitoring	1. Periodic visual inspection for external leaks. 2. Periodic leak- and functional test, minimum each 14 d.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leak in any of the elements, body or connections. 2. Unable to operate or malfunction.	

15.17 Table 17 – Coiled tubing strippers

Features	Acceptance criteria	See
A. Description	This element consists of a body with a sealing element and a riser connection.	
B. Function	The function of the stripper is to provide the primary pressure seal between the well bore and the atmosphere while allowing the CT string to move into or out of the well. The stripper is the upper closure device in the primary well barrier.	
C. Design, construction and selection	1. The pressure rating shall exceed the maximum expected differential pressure that it can become exposed to, including a margin for killing operations. 2. It shall be able to maintain a pressure seal with the CT string static, even if the power supply is lost.	NORSOK D-002 ISO 13533 ISO 15156-1 API RP 5C7
D. Initial test and verification	1. Function test after initial installation. 2. Perform low- and high-pressure leak tests after initial installation. 3. Leak test connections where seals have been de-energised to maximum expected WHP on following runs.	
E. Use	1. The hydraulic pressure shall be sufficient to maintain a dynamic pressure seal, but as low as possible to avoid excessive friction, wear and collapsing the CT string. 2. The upper stripper element shall be used as the primary stripper.	
F. Monitoring	1. Periodic visual inspection for external leaks. 2. Periodic leak- and functional test, minimum each 14 d.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leak in stripper element, body or connections. 2. Unable to operate or malfunction.	

15.18 Table 18 – Snubbing check valves

Features	Acceptance criteria	See
A. Description	The element consists of a body with a dual flapper check valve for mounting to the end of the workstring.	
B. Function	The function of the snubbing check valves is to prevent unintentional flow of formation fluid into the snubbing string and are primary WBEs.	
C.Design, construction and selection	1. It shall be designed to withstand all expected downhole forces and conditions. 2. Working pressure rating shall be equal to the maximum operating pressure. 3. It shall be provided with dual seals in the bore and provide internal and external sealing on the connections towards the snubbing string. 4. Provisions shall be made for pumping balls through the snubbing check valves. 5. Both check valves shall be installed in the BHA/work string prior to opening up the well.	NORSOK D-002
D. Initial test and verification	1. Low- and high-pressure leak test prior to connecting to the snubbing string. 2. Inflow test prior to each run in hole.	
E. Use	1. The snubbing check valves are connected directly to the end of the snubbing string and above BHA.	
F. Monitoring	1. Periodic inflow test.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leakage through the check valves.	

15.19 Table 19 – Snubbing BOP

Features	Acceptance criteria	See
A. Description	The element consists of riser and snubbing BOP with kill/choke line valves. The snubbing BOP normally consists of one lower pipe ram, one shear blind ram, one upper pipe ram and one annular preventer.	NORSOK D-002
B. Function	The function of the snubbing BOP is to prevent flow form the well bore in case of leakage in the snubbing string or stripper. **Annular** The annular preventer is also a stripping device and is capable of sealing around objects such as drill collars and un-perforated guns. It is used as a back up to the stripper rubber, pipe- and stripper rams. **Upper pipe ram** The purpose of the upper pipe ram is to maintain well control in the event of the failure of, or maintenance on, the highest primary closure device, i.e. a back up for either the stripper rubber or the stripping rams. When closing the pipe ram, or variable ram, circulation can be performed through the kill and choke lines below the shear/blind ram. The pipe ram is not designed for stripping. **Shear/blind ram** The shear/blind ram is part of the back up system in the primary well barrier. It can be the first option to use if cutting of the tubular is necessary **Lower pipe ram** The purpose of the lower pipe ram is to maintain well control in the event of the failure of, or maintenance to, active elements in the primary well control system, i.e. a back up element to the stripping rams or the stripper rubber. In an emergency the lower pipe ram can be used as a hang off mechanism below the shear/blind ram. The pipe ram is not designed for stripping.	
C. Design, construction and selection	1. It shall be constructed in accordance with NORSOK D-002. 2. The pressure rating shall exceed the maximum expected differential pressure that it can become exposed to, including a margin for killing operations. 3. It shall be documented that the shear blind ram can shear and seal the wellbore thereafter. If the manufacturer cannot document it, a qualification test shall be performed and documented. 4. The pipe ram shall be able to provide a seal on the snubbing annulus. 5. The seal/slip ram if used shall be able to seal and grip and hold the tubular. 6. A kill/choke inlet port shall be located between the shear blind ram and the lower pipe ram. It shall be possible to pump heavy fluid through the snubbing string after the BOP has been activated. 7. When using tapered tubulars there should be one fixed ram for each size.	NORSOK D-002 ISO 13533 ISO 15156-1
D. Initial test and verification	1. Function test after initial installation. 2. Perform low- and high pressure leak tests after initial installation. 3. Leak test connections where seals have been de-energised to maximum expected WHP on following runs.	
E. Use	The snubbing BOP elements shall be activated as described in the well control action procedures (contingency procedures need to be established by the user).	
F. Monitoring	Periodic visual inspection for external leaks. Periodic leak- and functional test, minimum each 14 d.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. See Table 2.	

15.20 Table 20 – Snubbing stripper

Features	Acceptance criteria	See
A. Description	The stripper consists of a rubber element inside a housing (stripper bowl). The element provides a seal towards the atmosphere based on the following principle: the workstring OD is larger than the stripper rubber ID. The system is based on wellbore pressure assist.	
B. Function	The function of the stripper is to provide the primary pressure seal between the well bore and the atmosphere while allowing the snubbing string to move into or out of the well.	
C. Design, construction and selection	1. The pressure rating shall exceed the maximum expected differential pressure that it can become exposed to, including a margin for killing operations. 2. The pipe OD and the well pressure to be taken into account when determining if the stripper rubber can be used to avoid ram-to-ram stripping.	NORSOK D-002 ISO 13533 ISO 15156-1
D. Initial test and verification	1. Leak test after initial installation. 2. Perform low- and high pressure leak tests after installation. 3. Leak test connections where seals have been de-energised to maximum expected WHP on following runs.	
E. Use	1. The pipe OD and the well pressure are taken into account when determining if the stripper rubber can be used to avoid ram-to-ram stripping.	
F. Monitoring	1. Periodic visual inspection for external leaks.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leak in stripper element, body or connections.	

15.21 Table 21 – Snubbing safety head

Features	Acceptance criteria	See
A. Description	The element consist of a connector and a shear/seal ram.	
B. Function	The function of the snubbing safety head (BOP) is to prevent flow form the well bore in case of loss or leakage in the primary well barrier at the surface. It shall be able to close in and seal the well bore with or without CT through the BOP. The safety head is the upper closure device in the secondary well barrier	
C. Design, construction and selection	1. The snubbing safety head shall be constructed in accordance with NORSOK D-002. 2. The pressure rating shall exceed the maximum expected differential pressure that it can become exposed to, including a margin for killing operations It shall be documented that the shear/seal ram can shear the workstring, CT or wireline and seal the wellbore thereafter. If the manufacturer cannot document this, a qualification test shall be performed and documented. 3. The safety head shall only be closed in an emergency and during testing. As there is normally no gauge between the safety head and the swab valve these two valves should not be in closed position at the same time. 4. The safety head shall be flanged close to the production tree.	NORSOK D-002 ISO 13533 ISO 15156-1
D. Initial test and verification	1. Function test after initial installation. 2. Perform low- and high leak tests after initial installation. 3. Leak test connections where seals have been de-energised to maximum expected WHP on following runs.	
E. Use	The snubbing safety head shall be activated as described in the well control action procedures (contingency procedures need to be established by the user).	
F. Monitoring	Periodic visual inspection for external leaks. Periodic leak- and functional test, minimum each 14 d.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. See Table 2.	

15.22 Table 22 – Casing cement

Features	Acceptance criteria	See
A. Description	This element consists of cement in solid state located in the annulus between concentric casing strings, or the casing/liner and the formation.	
B. Function	The purpose of the element is to provide a continuous, permanent and impermeable hydraulic seal along hole in the casing annulus or between casing strings, to prevent flow of formation fluids, resist pressures from above or below, and support casing or liner strings structurally.	
C. Design, construction and selection	1. A design and installation specification (cementing programme) shall be issued for each primary casing cementing job. 2. The properties of the set cement shall be capable to provide lasting zonal isolation and structural support. 3. Cement slurries used for isolating permeable and abnormally pressured hydrocarbon bearing zones should be designed to prevent gas migration. 4. The cement placement technique applied should ensure a job that meets requirements whilst at the same time imposing minimum overbalance on weak formations. ECD and the risk of lost returns during cementing shall be assessed and mitigated. 5. Cement height in casing annulus along hole (TOC): 5.1 **General:** Shall be 100 m above a casing shoe, where the cement column in consecutive operations is pressure tested/the casing shoe is drilled out. 5.2 **Conductor**: No requirement as this is not defined as a WBE. 5.3 **Surface casing**: Shall be defined based on load conditions from wellhead equipment and operations. TOC should be inside the conductor shoe, or to surface/seabed if no conductor is installed 5.4 **Casing through hydrocarbon bearing formations**: Shall be defined based on requirements for zonal isolation. Cement should cover potential cross-flow interval between different reservoir zones. For cemented casing strings which are not drilled out, the height above a point of potential inflow/ leakage point / permeable formation with hydrocarbons, shall be 200 m, or to previous casing shoe, whichever is less. 6. Temperature exposure, cyclic or development over time, shall not lead to reduction in strength or isolation capability. 7. Requirements to achieve the along hole pressure integrity in slant wells to be identified.	ISO 10426-1 Class ‘G’
D. Initial verification	1. The cement shall be verified through formation strength test when the casing shoe is drilled out. Alternatively the verification may be through exposing the cement column for differential pressure from fluid column above cement in annulus. In the latter case the pressure integrity acceptance criteria and verification requirements shall be defined. 2. The verification requirements for having obtained the minimum cement height shall be described, which can be • verification by logs (cement bond, temperature, LWD sonic), or • estimation on the basis of records from the cement operation (volumes pumped, returns during cementing, etc.). 3. The strength development of the cement slurry shall be verified through observation of representative surface samples from the mixing cured under a representative temperature and pressure. For HPHT wells such equipment should be used on the rig site.	
E. Use	None	
F. Monitoring	1. The annuli pressure above the cement well barrier shall be monitored regularly when access to this annulus exists. 2. Surface casing by conductor annulus outlet to be visually observed regularly.	WBEAC for “wellhead”
G. Failure modes	Non-fulfilment of the above requirements (shall) and the following: 1. Pressure build-up in annulus as a result of e.g. micro-annulus, channelling in the cement column, etc.	

15.23 Table 23 – Production tree isolation tool

Features	Acceptance criteria	See
A. Description	The tree saver is a temporary arrangement installed at top of the production tree to isolate the production tree and tubing hanger from treating pressure and fluids.	
B. Function	The function of the tree saver is to • isolate the production tree and tubing hanger from treating pressure whenever maximum treating pressures could exceed the maximum rated WP for the production tree/tubing hanger, or • isolate the production tree from abrasive fluids.	
C. Design, construction and selection	1. The WP of the tree saver shall as a minimum exceed the maximum anticipated treating pressure, plus 10 %. 2. The tree saver shall be flanged to the production tree with metal to metal seals. 3. The tree saver re-tract system shall be remote operated. 4. The tree saver shall have double valve system on the fluid inlet. Both valves shall be flanged to the tree saver with metal to metal seals. 5. The inner valve shall be hydraulically remote operated. 6. The seal stack which seals inside the tubing shall have a WP equal to the tree saver in the specific tubing ID it is designed to seal against.	
D. Initial verification	1. It shall be documented that the tree saver has been leak tested to 50% above the rated WP after last inspection. 2. After installation on the production tree the tree saver shall be leak tested to maximum production tree WP against upper or lower master valve. 3. Stable pressure in annulus between the tree saver and the production tree after pressure bled off in the production tree.	
E. Use	1. Discharge treating line shall have sufficient length such that the tree saver seal stack can be deployed and retracted with two well barriers in place.. 2. Wing valve on the production tree shall be open after sealing the tree saver seal stack and a bleed line shall be discharged to a non-hazardous location. The seal stack seal should be monitored throughout the operation.	
F. Monitoring	Annulus between the tree saver and the production tree shall be continuously monitored for pressure build up indicating leaking seal stack on the tree saver.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Inability to maintain a pressure seal.	

15.24 Table 24 – Cement plug

<table>
<tr><th>Features</th><th>Acceptance criteria</th><th>See</th></tr>
<tr><td>A. Description</td><td>The element consists of cement in solid state that forms a plug in the wellbore.</td><td></td></tr>
<tr><td>B. Function</td><td>The purpose of the plug is to prevent flow of formation fluids inside a wellbore between formation zones and/or to surface/seabed.</td><td></td></tr>
<tr><td>C. Design, construction and selection</td><td>1. A design and installation specification (cementing program) shall be issued for each cement plug installation.
2. The properties of the set cement plug shall be capable to provide lasting zonal isolation .
3. Cement slurries used in plugs to isolate permeable and abnormally pressured hydrocarbon bearing zones should be designed to prevent gas migration.
4. Permanent cement plugs should be designed to provide a lasting seal with the expected static and dynamic conditions and loads down hole
5. It shall be designed for the highest differential pressure and highest downhole temperature expected, inclusive installation and test loads.
6. A minimum cement batch volume shall be defined for the plug in order that homogenous slurry can be made, to account for contamination on surface, downhole and whilst spotting downhole.
7. The firm plug length shall be 100 m MD. If a plug is set inside casing and with a mechanical plug as a foundation, the minimum length shall be 50 m MD.
8. It shall extend minimum 50 m MD above any source of inflow/ leakage point. A plug in transition from open hole to casing should extend at least 50 m MD below casing shoe.
9. A casing/ liner with shoe installed in permeable formations should have a 25 m MD shoe track plug.</td><td>API Standard 10A Class ‘G’</td></tr>
<tr><td>D. Initial verification</td><td>1. Cased hole plugs should be tested either in the direction of flow or from above.
2. The strength development of the cement slurry should be verified through observation of representative surface samples from the mixing cured under a representative temperature and pressure.
3. The plug installation shall be verified through documentation of job performance; records fm. cement operation (volumes pumped, returns during cementing, etc.).
4. Its position shall be verified, by means of:
<table>
<tr><th>Plug type</th><th>Verification</th></tr>
<tr><td>Open hole</td><td>Tagging, or measure to confirm depth of firm plug.</td></tr>
<tr><td>Cased hole</td><td>Tagging, or measure to confirm depth of firm plug
Pressure test, which shall
a. be 7000 kPa (~1000 psi) above estimated formation strength below casing/ potential leak path, or 3500 kPa (~500 psi) for surface casing plugs, and
b. not exceed casing pressure test, less casing wear factor
which ever is lower
If a mechanical plug is used as a foundation for the cement plug and this is tagged and pressure tested the cement plug does not have to be verified.</td></tr>
</table></td><td></td></tr>
<tr><td>E. Use</td><td>Ageing test may be required to document long term integrity.</td><td></td></tr>
<tr><td>F. Monitoring</td><td>For temporary suspended wells: The fluid level/ pressure above the shallowest set plug shall be monitored regularly when access to the bore exists.</td><td></td></tr>
<tr><td>G. Failure modes</td><td>Non-compliance with above mentioned requirements and the following:
a. Loss or gain in fluid column above plug.
b. Pressure build-up in a conduit which should be protected by the plug.</td><td></td></tr>
</table>

15.25 Table 25 – Completion string

Features	Acceptance criteria	See
A. Description	This element consists of tubular pipe.	
B. Function	The purpose of the completion string as WBE is to provide a conduit for formation fluid from the reservoir to surface or vice versa.	
C. Design, construction and selection	1. All components in the completion string (pipe/housings and threads) shall have gas tight connections whenever exposed to hydrocarbons during its lifetime. 2. Dimensioning load cases shall be defined and documented. 3. The weakest point(s) in the string shall be identified. 4. Minimum acceptable design factors shall be defined. Estimated effects of temperature, corrosion, wear, fatigue and buckling shall be included in the design factors. 5. The tubing should be selected with respect to • tensile and compression load exposure, • burst and collapse criteria, • tool joint clearance and fishing restrictions, • tubing and annular flowrates, • abrasive composition of fluids, • buckling resistance, • metallurgical composition in relation to exposure to formation or injection fluid, • HPHT*:* Strength reduction due to temperatures effects.	
D. Initial test and verification	1. Pressure testing to METP. 2. HPHT: The tubular load bearing component of the completion string should be MPI inspected prior to HPHT exposure.	
E. Use	1. Stab-in safety valve and one way check valve for all type of connections exposed at the drill floor shall be readily available when the completion string is located inside the BOP.	
F. Monitoring	1. Pressure integrity is monitored through the annulus pressure.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leak to or from the annulus.	

15.26 Table 26 – High pressure riser

Features	Acceptance criteria	See
A. Description	The element is the riser including connectors and seals connecting the drilling BOP to the wellhead.	
B. Function	Its function is to act as an extension of the drilling BOP on platforms where the BOP and wellhead are positioned at different levels and thus prevent flow from the bore to the environment.	
C. Design construction selection	1. The pressure rating shall be MWDP including a margin for killing operations. 2. All sealing elements shall be resistant to maximum estimated exposure temperature and fluid system used. 3. Connectors shall be of a gas tight design for the expected loads.	ISO 13533 API RP 53
D. Initial Test and Verification	1. Shall be leak tested to maximum expected shut in pressure for the specific hole section or operation.	
E. Use	1. Shall be maintained, inspected and installed according to established procedures.	
F. Monitoring	1. Shall be leak tested if reinstalled.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leaking riser.	

15.27 Table 27 – Well test string

Features	Acceptance criteria	See
A. Description	This element consists of tubular pipe.	
B. Function	The purpose of the drill stem test string as WBE is to provide a conduit for formation fluid from the reservoir to surface.	
C. Design, construction and selection	1. The components (pipe and threads) shall be gas tight. Regular full hole or internal flush connections are not allowed unless equipped with o-ring seals. 2. Dimensioning load cases shall be defined and documented. 3. The weakest point(s) in the string shall be identified. 4. Minimum acceptable design factors shall be defined. Estimated effects of temperature, wear, fatigue and buckling shall be included in the design factors. 5. Drill stem drill pipe should be selected with respect to • make-up torque necessary to prevent make-up in the well, • tool joint clearance and fishing restrictions, • pumping pressure and ECD, • buckling resistance, • hard banding and its influence on casing wear, • metallurgical composition in relation to exposure to reservoir or other corrosive environment, • fatigue resistance, • HPHT: Strength reduction due to temperatures effects. 6. HPHT: The threaded connections should be cold rolled.	NORSOK D-SR-007
D. Initial test and verification	1. Pressure testing to METP. 2. HPHT: The component of the drill string should be MPI inspected prior to HPHT mode status.	
E. Use	1. Stab-in safety valve and one way check valve for all type of connections exposed at the drill floor shall be readily available when the drill stem test string is located inside the BOP.	
F. Monitoring	1. Pressure integrity is monitored by independence of the annulus pressure.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leak to or from the annulus.	

15.28 Table 28 – Mechanical tubular plugs

Features	Acceptance criteria	See
A. Description	This is a mechanical plug set anywhere inside steel conduits (casing/tubular).	
B. Function	The purpose of the element (plug) is to prevent flow of formation fluids and resist pressure from above or below, inside tubulars and in the annulus space between concentric positioned tubulars.	
C. Design, construction and selection (rating, capacity, etc.)	1. The plug shall be designed for the highest differential pressure and highest downhole temperature expected. Installation and test loads shall also be considered. 2. Down hole fluids and conditions (temperature, H_2S, CO_2, etc.) shall be considered in estimating the life time of the plug. 3. Shall, if used as a WBE in production/ injection, comply with ISO 14310 as follows: • Grade V1 for design validation, • Grade Q1 for quality control. 4. The plug shall be designed such that pressure can be equalized across the plug, if removed mechanically or by drilling out. 5. The plug is not accepted as a WBE alone in permanent plugging of wells or branches of wells, where design integrity in an eternal perspective is required. 6. To ensure the well barrier integrity in using the plug, it shall only be installed in a tubular section of the well, which is cemented, or supported by sufficient wall thickness to withstand loads from the plug.	ISO 14310
D. Initial verification	1. If possible the plug shall be inflow tested (from below), else it shall be leak tested from above. Pressure shall 1. be minimum 7000 kPa (~1000 psi) above measured formation strength below casing/ potential leak path, (3500 kPa (~500 psi) for surface casing). 2. not exceed casing pressure test, which ever is lower.	
E. Use	Inadvertent release of the plug by mechanical motion/ impact shall not be possible.	
F. Monitoring	Pressure integrity shall be monitored through recording of the pressure above the plug.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Inability to maintain a pressure seal.	

15.29 Table 29 – Completion string component

Features	Acceptance criteria	See
A. Description	These elements consist of a housing with a bore. The element may have a sidemounted feature or a valve providing communication between tubing and annulus.	
B. Function	Its purpose may be to provide support to the functionality of the completion, i.e. gas-lift or side pocket mandrels with valves or dummies, nipple profiles, gauge carriers, control line filter subs, etc.	
C. Design, construction and selection	1. The components (pipe and threads) shall be gas tight. 2. Minimum acceptable design factors shall be defined. Estimated effects of temperature, corrosion, wear; fatigue and buckling shall be included in the design factors. 3. The component should be designed/selected with respect to • burst and collapse criteria, • tensile and compression load exposure, • OD clearance and fishing restrictions, • tubing (and annular) flowrates, also including erosion effects, • metallurgical composition in relation to exposure to formation, injection or annulus fluid, • odd shaped assemblies in casting material shall be subject to finite element analysis, • HPHT: Strength reduction due to temperatures effects. 4. For gaslift valves to qualify as a well barrier there shall be a qualification test demonstrating the valves ability to be gas tight over an operator defined number of cycles. The valve shall be subject to frequent testing with acceptable results similar to testing of SCSSVs	
D. Initial test and verification	1. Pressure testing to METP.	
E. Use	1. Running of intervention tools shall not accidentally change a functionality of the tool.	
F. Monitoring	1. Pressure integrity is monitored by independence of the annulus pressure.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Inability to maintain a pressure seal.	

15.30 Table 30 – Snubbing string

<table>
<tr><th>Features</th><th>Acceptance criteria</th><th>See</th></tr>
<tr><td>A. Description</td><td>This element consists of a string with jointed tubular.</td><td></td></tr>
<tr><td>B. Function</td><td>The function of the snubbing string as a WBE is to prevent flow of formation fluid from its bore to the external environment.</td><td></td></tr>
<tr><td>C. Design, construction and celection</td><td>1. Dimensioning load cases shall be defined and documented.
2. Minimum acceptable design factors shall be defined. Estimated effects of temperature, corrosion, wear, fatigue and buckling shall be included in the design factors.
3. Snubbing string design dasis, premises and assumptions.
The following should be considered for the design of a snubbing string:
• weight,
• over pull,
• wellbore condition,
• hydraulically applied loads,
• transition point,
• maximum length,
• buckling,
• fatigue.
4. For snubbing operations the type of connection to be used above the check valves to meet the requirement of minimum two each gas tight metal-to-metal seal. The seals to withstand internal and external pressure.</td><td>ISO 11960
NORSOK D-002</td></tr>
<tr><td>D. Initial test and verification</td><td>1. Leak test after initial rig-up.
2. Leak test to maximum expected WHP on following runs.
3. The plug for the nipple profile shall be leak tested to high and low pressure for 5 min to 10 min "on stump" before first run. It is not required to repeat this test if same equipment is used on later runs during the same operation.</td><td></td></tr>
<tr><td>E. Use</td><td>1. A double / dual check valve assembly or a fail-safe closing device to prevent unintentional flow of formation fluid into the snubbing string shall be used.
2. A nipple profile shall be installed in the BHA to be used for internal well control if the check valves fail, i.e. back up to the check valves.</td><td></td></tr>
</table>

Features	Acceptance criteria	See
F. Monitoring	1. Pump pressure and wellhead pressure shall be continuously monitored during the operation. 2. Maintenance and certification of used tubular goods. Tubular goods (including end connections and any end connection - pipe body transition area/upset) shall be maintained and recertified to a specified minimum condition based on documented procedures. Procedures shall as a minimum cover the following: • Tubular goods shall be free of defects that may jeopardize the certified minimum condition of the tubular goods. • Minimum effective wall thickness and extent of reduced wall thickness, internally, externally or as a combination, at any location of the tubular goods shall be known and documented. • End connections shall fulfill the design owner's requirements with regards to inspection, minimum acceptable condition, repair and maintenance. 3. End connection compatibility: When compatible end connections designs are being used, compatibility shall be certified by all relevant end connection design owners.	NORSOK D-002
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leakage through snubbing string and the dual check valves are not holding pressure. 2. Changes or damage to the snubbing string geometry preventing the stripper to maintain a pressure seal.	

15.31 Table 31 – Sub-sea production tree

Features	Acceptance criteria	See
A. Description	This element consists of a housing with bores that are fitted with production and annulus master-, swab- and flow valves.	
B. Function	Its function is to • provide a flow conduit for hydrocarbons from the tubing into the subsea to surface lines with the ability to stop the flow by closing the flow valve and/or the PMV, • provide monitoring and pressure adjustment of the annulus, • provide vertical tool access through the swab valve(s).	
C. Design, construction and selection	1. The subsea production tree shall be equipped with • one automatic master valve and one automatic wing valve in the main flow direction of the well, • if the production tree has side outlets, these shall be equipped with automatic fail-safe valves at short intervals, • one manual swab valve for each bore at a level above any side outlets (applies to vertical trees), • isolation valves on downhole control lines which penetrates the production tree block.	ISO 13628-4
D. Initial test and verification	1. The valves shall be tested with both low and high (MEDP) differential pressure in the direction of flow. The low pressure test shall be 3,5 MPa.	
E. Use	1. Employ a strategy for use of antifreeze/hydrate agents during shut-ins and testing. 2. Beware of equalization during opening and closing of valves.	
F. Monitoring	1. The principal valves acting as barriers in the production tree shall be tested at regular intervals as follows: • test duration shall be 10 min, • monthly, until three consecutive qualified tests have been performed, thereafter - • every three months, until three consecutive qualified tests have been performed, thereafter – • every six months. 2. If the leak rate cannot be measured directly, indirect measurement by pressure monitoring of an enclosed volume downstream of the valve shall be performed.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Failure to pass the regular test.	

15.32 Table 32 – Sub-sea test tree

Features	Acceptance criteria	See
A. Description	This element consists of two main parts: A lower part with a fluted hanger, slick joint, housing with two fail-safe close valve, and an upper disconnectable part consisting of a housing with a latching mechanism, control lines and chemical injection line(s) with check valves.	
B. Function	Its function is to seal the well from below, and allow the test string to be disconnected below the BOP shear seal ram, allowing this to be closed, before a subsequent and possible riser disconnect.	
C. Design, construction and selection	1. It shall be equipped with a surface remote opening, fail-safe closing and un-latch/re-latch function. For contingency purposes a mechanical unlatch feature shall also be available. 2. It shall be landed in the well head, allowing one of the pipe rams to seal around a slick joint isolating the test string annulus. 3. It shall be sufficiently short to allow the BOP shear seal ram to be closed above the tree valve assembly while valve and latch mechanism is connected. 4. A shearable joint shall be installed above the tree to facilitate emergency cutting of the string.	NORSOK D-SR-007
D. Initial test and verification	1. The SSTT spacing in the BOP stack shall be verified with a dummy run unless already proven. 2. It shall be leak tested and the latch mechanism shall be function tested (unlatch/latch) on rig floor after it has been made up to the test string. 3. It shall be leak tested after it has been positioned inside the BOP.	
E. Use	1. The SSTT valve shall not be used as an operational valve during well test operations, only as a contingency device in preparation or conjunction with disconnect of the test string.	
F. Monitoring	1. Ascertain pressure integrity of umbilical control line and availability of control line fluid. 2. Monitor pressure in BOP between SSTT valve and BOP SSR, prior to re-entry of a disconnected test string/riser.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Inability to pass pressure testing or monitoring requirements.	

15.33 Table 33 – Surface production tree

Features	Acceptance criteria	See
A. Description	This element consists of a housing with bores that are fitted with swab-, production master-, kill- and flow valves.	
B. Function	Its function is to • provide a flow conduit for hydrocarbons from the tubing into the surface lines with the ability to stop the flow by closing the flow valve and/or the master valve, • provide vertical tool access through the swab valve, • provide an access point where kill fluid can be pumped into the tubing.	
C. Design, construction and selection	1. The surface production tree shall be equipped with • one automatic master valve and one automatic wing valve in the main flow direction of the well, • if the production tree has flowing side outlets, these shall be equipped with automatic fail-safe valves at short interval from the tree, • one manual swab valve for each bore at a level above any side outlets, • isolation valves on downhole control lines which penetrates the production tree block. 2. All primary seals (inclusive production annulus) shall be of metal-to-metal type. 3. All connections, exit blocks etc. that lies within a predefined envelope shall be fire-resistant.	API Spec 6FA, API Spec 6FB and API Spec 6FC
D. Initial test and verification	1. The valves shall be tested with both low and high (MEDP) differential pressure in the direction of flow. The low pressure test shall be 3,5 MPa.	
E. Use	1. Employ a strategy for use of antifreeze/hydrate agents during shut-ins and testing. 2. Beware of equalization during opening and closing of valves.	
F. Monitoring	1. The principal valves acting as barriers in the production tree shall be tested at regular intervals as follows: • test duration shall be 10 min, • monthly, until three consecutive qualified tests have been performed, thereafter - • every three months, until three consecutive qualified tests have been performed, thereafter – • every six months. 2. If the leak rate can not be measured directly, indirect measurement by pressure monitoring of an enclosed volume downstream of the valve shall be performed.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Failure to pass the regular test.	

15.34 Table 34 – Surface test tree

Features	Acceptance criteria	See
A. Description	This element consists of a housing with bores that are fitted with swab-, master-, kill- and flow valves. It can also contain a swivel with internal seals.	
B. Function	Its function is to • provide a flow conduit for hydrocarbons from the test tubing or the work over riser and into the surface lines with the ability to stop the flow by closing the flow valve and/or the master valve, • provide kill fluid injection capabilities through the kill valve and vertical tool access through the swab valve, • if swivel is used, allow rotation of the STT segment that is above the swivel.	
C. Design, construction and selection	1. It shall be equipped with a remote operated wing and kill valve, wing valve shall be of fail safe close type. 2. The wing valve shall be possible to interconnect with the PSD/ESD system. 3. If the tree is equipped with a swivel, this shall be placed above the master valve. 4. It shall be equipped with a facility to attach a working platform to ease rigging up of equipment on top of the swab valve. 5. Maximum effort shall be made to select a lightweight and easy manageable tree for handling purposes on the rigfloor.	NORSOK D-SR-007
D. Initial test and verification	1. All components shall be pressure tested to maximum expected well pressure after it has been made up to test string. 2. The wing valve shall be function tested under expected flowing pressure (not maximum pressure) conditions. The closure response time shall be verified to be within 5 s.	
E. Use	1. For floaters the STT with attached kill, production and control lines attached to the tree shall have clear travel over the entire compensating stroke at both high and low tide. 2. For floaters maximum heave limitation shall be set to trigger a controlled landing string disconnect before rig movements become critical.	
F. Monitoring	1. It is recommended that the tree is equipped with pressure and temperature sensors upstream the PWV. 2. If the tree is equipped with a swivel this shall be made subject to regular visual inspection for sign of leaks during the operation.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Inability to pass pressure testing requirements.	

15.35 Table 35 – Well test packer

Features	Acceptance criteria	See
A. Description	This element consists of an annular seal element placed outside the tubing against the casing of the well.	
B. Function	Its purpose is to provide a principal seal, separating communication between the formation and the annular space around the tubing.	
C. Design, construction and selection	1. The packer shall be permanently set or retrievable and hold pressure from above and below, accepting as a minimum downward load. 2. It shall be possible to un-set and re-set the retrievable packer without changes in performance. 3. The seal shall withstand MEDP. Maximum expected differential pressure across the packer shall be calculated based on (whichever gives the highest) the following: • applied pressure to the annulus less minimum reservoir pressure, • reservoir pressure less hydrostatic pressure of fluid in annulus, • leaking tubing, equal to wellhead shut-in pressure plus, hydrostatic pressure of fluid in annulus less reservoir pressure, • evacuated tubing with pressure on annulus. 4. The well test packer shall be tested as per ISO 14310, and the class it has been tested to shall be quoted. The test should be conducted in unsupported, non-cemented, standard casing. 5. HPHT wells: Fully anchored (permanent) packers should be used. 6. Underbalanced well testing: A fully anchored (permanent) packer with pressure retaining ability from below shall be used.	NORSOK D-SR-007
D. Initial test and verification	1. The packer shall be tested to MEDP. 2. If possible the packer shall be tested from below, if this is not possible it should be tested from above.	
E. Use	1. A fluid column (Table 1) shall be in place above the packer. 2. Running of intervention tools shall not impair the packers ability to seal nor inadvertedly cause the temporarily anchored packer to be released.	
F. Monitoring	1. Sealing performance shall be monitored through continuous recording of the annulus pressure measured at wellhead level.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Inability to maintain a pressure seal.	

15.36 Table 36 – Well test string components

Features	Acceptance criteria	See
A. Description	These elements consist of a housing with a bore. The element may have a sidemounted feature or a valve providing communication between tubing and annulus.	
B. Function	Its purpose may be to provide support to the functionality of the test string, i.e. slip joints, circulating valves, sampling tools, nipple profiles, gauge carriers, safety joints, jars, etc.	
C. Design, construction and selection	1. The components (pipe and threads) shall be gas tight. 2. Minimum acceptable design factors shall be defined. Estimated effects of temperature, corrosion, wear, fatigue and buckling shall be included in the design factors. 3. The component should be designed/selected with respect to • burst and collapse criteria, • tensile and compression load exposure, • jarring effects required to release a stuck test string, • OD clearance and fishing restrictions, • tubing flowrates, also including erosion effects, • metallurgical composition in relation to exposure to formation, injection or annulus fluid, • welding or odd shaped casting assemblies should be avoided, • HPHT: Strength reduction due to temperatures effects to be applied.	NORSOK D-SR-007
D. Initial test and verification	1. Pressure testing to METP.	
E. Use	1. Running of intervention tools shall not accidentally shift a functionality of the tool.	
F. Monitoring	1. Pressure integrity is monitored by stability of the annulus pressure.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Inability to maintain a pressure seal.	

15.37 Table 37 – Wireline BOP

Features	Acceptance criteria	See
A. Description	This element consists of a BOP body with rams and riser/lubricator connections.	
B. Function	The function of the WL BOP is to prevent flow from the well bore in case leakage in stuffing box / grease head or lubricator system above the BOP. The element is a back-up element to the stuffing box/grease head in the primary well barrier.	
C. Design, construction and selection	1. The WL BOP shall be constructed in accordance with NORSOK D-002. 2. The pressure rating shall exceed the maximum expected differential pressure that it can be exposed to, including a margin for killing operations. 3. The cable ram shall be able to provide a seal on the selected cable size. 4. For slick line operations in live wells a minimum of one cable ram shall be installed. 5. For braided line operations in live wells a minimum of two cable rams shall be installed, with the lower ram capable of holding pressure from above. A system for pumping grease between the rams shall be included to prevent gas migration through the cable armour.	NORSOK D-002 ISO 13533 ISO 15156-1 API RP 5C7
D. Initial test and verification	1. Function test after installation. 2. Perform low- and high pressure leak tests after initial installation. 3. Leak test connections where seals have been de-energised to maximum expected WHP on following runs.	
E. Use	1. The WL cable rams shall be activated as described in the well control action procedures (contingency procedures has to be established).	
F. Monitoring	1. Periodic visual inspection for external leaks. 2. Periodic leak-and functional test, minimum each 14 d when in operation.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leak in any of the elements, body or connections. 2. Leak in hydraulic operating system. 3. Unable to operate or malfunction.	

15.38 Table 38 – Wireline safety head

Features	Acceptance criteria	See
A. Description	This element consists of a body with a shear/seal ram and riser connections.	
B. Function	Its function is to prevent flow from the well bore in case of loss or leakage in the primary well barrier at the surface. It shall be able to close in and seal the well bore with or without cable through the safety head. The element is the upper closure device in the secondary well barrier.	
C. Design, construction and selection	1. The WL safety head shall be constructed in accordance with NORSOK D-002. 2. The pressure rating shall exceed the maximum expected differential pressure that it can be exposed to, including a margin for killing operations. 3. It shall be documented that the shear/seal ram can shear the selected cable types and seal thereafter. 4. The riser/lubricator between the XT and safety head shall be as short as possible. The number of connections between the XT and safety head is critical and shall be kept to a minimum.	NORSOK D-002 ISO 13533 ISO 15156-1 API RP 5C7
D. Initial test and verification	1. Function test after installation. 2. Perform low- and high pressure leak tests after initial installation. 3. Leak test connections where seals have been de-energised to maximum expected WHP on following runs.	
E. Use	1. The WL safety head shall be activated as described in the well control action procedures (contingency procedures need to be established by the user). 2. The safety head shall normally only be closed in an emergency and during leak-and function testing.	
F. Monitoring	1. Periodic visual inspection for external leaks. 2. Periodic leak-and functional test, minimum each 14 d when in operation.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leak in the element, body or connections. 2. Leak in hydraulic operating system. 3. Unable to operate or malfunction.	

15.39 Table 39 – Wireline stuffing box/grease Injection head

Features	Acceptance criteria	See
A. Description	This element consists of a body with a hydraulic operated sealing system and a lubricator connection.	
B. Function	The function is to provide the primary pressure seal between the well bore and the atmosphere while allowing the WL to move into or out of the well. This is the upper closure device in the primary well barrier.	
C. Design, construction and selection	1. The WL stuffing box/grease head shall be constructed in accordance with NORSOK D-002. 2. The pressure rating shall exceed the maximum expected differential pressure that it can be exposed to. 3. A blow out plug or ball check valve shall be included in case of wire breakage.	NORSOK D-002 ISO 13533 ISO 15156-1 API RP 5C7
D. Initial test and verification	1. Function test after installation. 2. Perform low- and high pressure leak tests after initial installation. 3. Leak test connections where seals have been de-energised to maximum expected WHP on following runs.	
E. Use	1. The activation/grease injection pressure shall be sufficiently high to maintain a dynamic pressure seal, and simultaneously as low as possible to avoid excessive friction when moving the cable.	
F. Monitoring	1. Visual periodic inspection.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leak in sealing system, body or connections. 2. Unable to operate/malfunction. 3. Excessive grease consumption.	

15.40 Table 40 – Stab in safety valve

Features	Acceptance criteria	See
A. Description	This element consists of a housing with a bore and a ball valve.	
B. Function	Its purpose is to allow mounting and closure at the top of any free tubular joint sitting in the rotary table.	
C. Design, construction and selection	1. The valve shall be rated to maximum expected WHP. 2. The valve shall have an easily accessible and operable closure mechanism for use once the valve is installed on the string.	
D. Initial test and verification	1. The valve shall have a documented and accepted test performed within the last 14 d.	
E. Use	1. The stab-in safety valve shall be made up with threaded connections to match the tubing joint sitting in the rotary table at any time. 2. The valve shall be possible to make up hand-tight in less than 15 s.	
F. Monitoring	1. Visual observation during use.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Inability to maintain a pressure seal.	

15.41 Table 41 – Casing float valves

Features	Acceptance criteria	See
A. Description	The element consists of a tubular body with pin and box threads and an internal one-way valve.	
B. Function	The purpose is to prevent flow of fluids from the well bore up the casing/liner during installation of casing/liner and to allow for circulating the well.	
C. Design construction selection	1. The element shall allow for pumping fluids down the casing/liner but prevent any flow in the opposite direction. 2. The element shall withstand expected burst, collapse and axial loads including design factors. 3. The working/sealing pressure of the element shall be equal to the maximum expected differential pressure across the element plus a defined safety factor. 4. The element shall function at expected well bore conditions with regards to differential pressure, temperature and fluid characteristics.	ISO 10427-3
D. Initial test and verification	1. Specifications and performance shall be documented by vendor. 2. Should be inflow-/function tested during casing/liner running.	
E. Use	Shall be installed according to vendor's procedure.	
F. Monitoring	Not applicable after initial testing.	
G. Failure modes	1. Failure to install according to procedure. 2. Failure to inflow test.	

15.42 Table 42 – Lower riser package

Features	Acceptance criteria	See
A. Description	This element consists of a valve body with a shear/seal ram and a riser connector.	
B. Function	The function of the LRP is to prevent flow from the well bore in case of loss or leakage in the primary well barrier at the surface. It shall be able to close in and seal the well bore with or without CT or wireline through the LRP. The LRP is the upper closure device in the secondary well barrier.	
C. Design, construction and selection	1. The LRP shall be designed in accordance with ISO/DIS 13628-7. 2. The pressure rating shall exceed the maximum expected differential pressure that it can be exposed to, including a margin for killing operations. 3. It shall be documented that the shear/seal ram can shear the CT or wireline and seal the wellbore thereafter. If this cannot be documented by the manufacturer, a qualification test shall be performed and documented.	ISO/DIS 13628-7 NORSOK D-002 ISO 13533 ISO 15156-1 API RP 5C7
D. Initial test and verification	1. Function test after initial installation. 2. Leak test after initial installation. 3. Leak test connections where seals have been de-energized to maximum expected WHP on following runs.	
E. Use	1. The LRP shall be activated as described in the well control action procedures (contingency procedures need to be established by the user).	
F. Monitoring	1. Periodic visual inspection for external leaks. 2. Periodic leak- and functional test, minimum each 14 d.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leak in any of the elements, body or connections. 2. Unable to operate or malfunction.	

15.43 Table 43 – Liner top packer

Features	Acceptance criteria	See
A. Description	This is a mechanical plug, consisting of a tubular body with an external seal element, set in the liner lap between casing and liner.	
B. Function	Its purpose is to provide a hydraulic seal in the annulus between the casing and liner, to prevent flow of formation fluids, and resist pressures from above or below.	
C. Design, construction and selection (rating, capacity, etc.)	1. The packer shall be designed for the highest differential pressure and highest downhole temperature expected during installation, acceptance testing and throughout its service life. Other down hole conditions, such as formation fluids, H_2S, CO_2, etc. shall also be considered in estimating the lifetime of the packer. NOTE - It is not accepted as a WBE in permanently abandoned wells or well bores. 2. The risk of sealing failure due to variable downhole temperatures/cyclic loading shall be evaluated. 3. It shall comply with ISO 14310 when used as a WBE in production/injection, as follows: • Grade V1 for design validation, • Grade Q1 for quality control. 4. It shall be able to seal in oval, worn or scored casing. 5. It shall not need the support of cement in the liner annulus to seal. 6. It shall be designed to avoid prematurely setting and allow rotation before set.	ISO 14310
D. Initial verification	It shall be pressure tested from above, and for development wells inflow tested if practicably possible. The pressure shall • be minimum 7000 kPa (~1000 psi) above measured formation strength below casing/ potential leak path, • not exceed casing pressure test. which ever is lower.	
E. Use	None	
F. Monitoring	None	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Inability to maintain a pressure seal.	

15.44 Table 44 – Wireline lubricator

Features	Acceptance criteria	See
A. Description	This element consists of a body with a lubricator connection in both ends.	
B. Function	The function is to provide lubricate space for BHA over the closing device when run into and out of well.	
C. Design, construction and selection	1. The WL lubricator shall be constructed in accordance with NORSOK D-002. 2. The pressure rating shall exceed the maximum expected differential pressure that it can be exposed to, including a margin for killing operations.	NORSOK D-002 ISO 13533 ISO 15156-1 API RP 5C7
D. Initial test and verification	1. Function test after installation. 2. Perform low- and high pressure leak tests after initial installation. 3. Leak test connections where seals have been de-energised to maximum expected WHP on following runs.	
E. Use	1. The total length of lubricators shall allow sufficient height, above the upper well closing device, to contain the complete toolstring including items pulled from the well.	
F. Monitoring	1. Visual periodic inspection.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leak through body or connections. 2. Damaged threads or connections.	

15.45 Table 45 – Subsea lubricator valve for well testing

Features	Acceptance criteria	See
A. Description	This element consists of a housing with a bore and a valve.	
B. Function	Its purpose is to seal off the bore in the landing string to allow lubrication of long wireline or CT tools without having to close the SSTT and depressurize the entire landing string.	
C. Design, construction and selection	1. The valve shall have a pump through feature at the same time as being able to be pressure tested from both directions. 2. The valve shall be fail as is. 3. Pressure lock between multiple valves shall not be possible. 4. Chemical injection shall be included (typically for hydrate prevention purposes)	NORSOK D-SR-007
D. Initial test and verification	1. It shall be pressure tested to maximum expected well pressure from both directions, once the test string is landed in the wellhead.	
E. Use	1. It is recommended to run two lubricator valves in tandem, the lower valve acting as the well barrier whilst the upper act as a mechanical buffer should the toolstring accidentally drop during rigging up.	
F. Monitoring	1. Regular inflow or pressure testing in conjunction with every time use.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Inability to maintain a pressure seal.	

15.46 Table 46 – Downhole tester valve

Features	Acceptance criteria	See
A. Description	This element consists of housing and a valve, located shortly above the test packer.	
B. Function	Its function is to provide a seal in the test tubing bore when • downhole shut-in for pressure build-up, • circulating the well to kill fluid through a circulating device, • running the test string with different densities of the fluids in the test string and the wellbore.	
C. Design, construction and selection	1. Shall be operated by annulus pressure. 2. Shall hold pressure from above and below. 3. Shall have a pump through feature.	NORSOK D-SR-007
D. Initial test and verification	1. The valve should be leak tested in the direction of flow and function tested on deck and after it has been installed on the test string.	
E. Use	1. The valve shall not be operated after initial testing for the period it is acting as a well barrier while RIH.	
F. Monitoring	1. RIH with downhole tester valve closed: the test string should be kept full of fluid and monitored for flow/losses. 2. There are no requirements for frequent testing after the initial verification test.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Failure to pass the initial test leak monitoring while RIH.	

15.47 Table 47 – Snubbing stripper BOP

Features	Acceptance criteria	See
A. Description	The element consists of two each BOP rams with equalizer and bleed off line valves. The stripper BOP normally consists of one lower stripper ram and one upper stripper ram.	NORSOK D-002
B. Function	The stripping rams are utilized to allow for controlled movement of upset and non-upset tubular in wells with surface pressure. By means of alternating between opening and closing the two stripping rams, tool joints can be stripped in/out the well while retaining full control of tubing annulus, i.e. the stripping rams are the highest primary WBEs when snubbing "ram-to-ram". The stripping rams are defined as back up WBEs if the stripper rubber is used when RIH or pulling out of hole.	
C. Design, construction and selection	1. It shall be constructed in accordance with NORSOK D-002. 2. Its WP shall exceed the MWDP including a margin for killing operations. 3. The stripper ram shall be able to provide a seal on the snubbing annulus. 4. The stripper rams shall be equipped with ram blocks designed for stripping.	NORSOK D-002 ISO 13533 ISO 15156-1
D. Initial test and verification	1. Function test after initial installation. 2. Perform low- and high pressure leak tests after initial installation. 3. Leak test connections where seals have been de-energised to maximum expected WHP on following runs.	
E. Use	The stripper BOPs shall be activated as described in the well control action procedures (contingency procedures).	
F. Monitoring	Periodic visual inspection for external leaks. Periodic leak- and functional test, minimum each 14 d.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. See Table A.2.	

15.48 Table 48 – Rotating control device

Features	Acceptance criteria	See
A. Description	The RCD is a drill through device with a rotating seal that is designed to contact and seal against the work string (drill string, casing, completion string, etc.) for the purpose of controlling the pressure and fluid flow to surface.	
B. Function	Its function is to contain fluids in the wellbore and divert flow from the wellbore to the surface fluids handling equipment during underbalanced operations (drilling, tripping and running completion equipment).	
C. Design, construction and selection	1. The selected RCD shall be fit for purpose to operate as designed within the expected operating pressure envelope. 2. Design should be such that change out of the primary seal elements is possible with the work string in the well. 3. The selected RCD shall have a dynamic pressure rating greater than or equal to the maximum expected pressure while rotating the work string and packing element. 4. The sealing elements of the selected RCD shall be compatible with the operating fluid environment (liquid, gas and multiphase) expected. 5. The sealing elements of the selected RCD shall be compatible with the expected operating temperature envelope. 6. The RCD shall by design be capable of withstanding vibration and shock loads without failure of the sealing mechanisms. 7. All metallic materials, which come in contact with well fluids, shall meet the requirements of ISO 15156-1 for sour service.	ISO 13533 and other valid RCD specifications Specific to elastomer testing ASTM D412 ASTM D471 ASTM G111 ASTM D2240
D. Initial test and verification	1. The RCD shall prior to delivery pass a documented pressure test to 3,5 MPa for 5 min and to the static pressure rating of the RCD for 10 min. 2. Material certificates for the RCD and components shall be available. 3. On initial installation on location, the RCD shall be leak tested to 3,5 MPa for 5 min and to the static pressure rating of the RCD for 10 min. 4. After initial installation, pressure integrity of replacement sealing elements shall be verified by testing with the maximum available well pressure at surface.	
E. Use	Sealing element wear is dependent on the hydraulic closing and or the wellhead pressure while stripping pipe and tool joints through the elements. This should be kept to the minimum required to prevent leakage past the elements.	
F. Monitoring	Pressure monitoring across elements and visual checks for continuous leaks past seal elements during operation.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Rig not centered on well. 2. Failure of leak tests and continuous leaks in seal elements, body or connections during operation.	

15.49 Table 49 – Downhole isolation valve

Features	Acceptance criteria	See
A. Description	The DIV is a full-opening drill through valve, installed down-hole as an integral part of a casing/liner string, at a depth either below the maximum pipe light depth for the work string being tripped in the underbalanced operation (drill string, casing, completion string, etc.) or at a depth that allows the maximum length of BHA, slotted liner or sand screen required to be safely deployed, without having to snub in or kill the well prior to deployment.	
B. Function	The DIV functions as the primary down-hole well barrier, isolating the open hole section with reservoir from the fluid system above the DIV.	
C. Design, construction and selection	1. The selected DIV shall at a minimum meet the burst and collapse design criteria for the casing/liner string of which it is an integral component. 2. The selected DIV shall be fit for purpose to operate as designed within the expected operating pressure envelope. 3. The DIV shall by design be capable of withstanding vibration, shock loads, rotating tool joints and exposure to a high solids environment without failure of the sealing mechanisms. 4. Working pressure rating of the selected DIV shall at a minimum be equal to the maximum expected differential pressure after closure. 5. The sealing elements of the selected DIV shall be compatible with the operating fluid environment (liquid, gas and multiphase) expected and the expected operating temperature envelope. 6. All metallic materials, which come in contact with well fluids, shall meet the requirements of ISO 15156-1 for sour service. 7. The DIV shall by design positively indicate to the operator at surface, the relative position of the shutoff mechanism (open/close).	ISO 10432, API RP 14B, and other valid DIV specifications Specific to elastomer testing ASTM D412 ASTM D471 ASTM G111 ASTM D2240
D. Initial test and verification	1. The DIV shall prior to delivery pass a documented differential pressure test to 3,5 MPa for 5 min and to the WP rating for 10 min with a gas medium and shall not leak. Testing shall be in the direction of flow. 2. Material certificates for the DIV and components shall be available. 3. After initial installation on location, the DIV shall be leak tested to 3,5 MPa for 5 min and to the rated WP rating of the DIV for 10 min. Testing shall be in the direction of flow. 4. After initial installation, pressure integrity of the DIV as a working well barrier shall be verified by inflow testing with the BHA above the DIV, prior to tripping out with the work string.	
E. Use	The DIV is connected to the last casing or tubing run prior to drilling underbalanced in the reservoir section to be isolated with the DIV. To prevent impairment of the reservoir, the well bore below the down-hole valve shall contain only reservoir-induced fluids (no drill fluid) prior to shutting in.	
F. Monitoring	Pressure monitoring across the shut-in valve and/or inflow tests for continuous leak through the shut in valve with the BHA above the DIV, prior to tripping out with the work string.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Dropped object on the shut-in valve or inadvertently running into the closed valve with the work string. 2. Buildup of solids across the valve.	

15.50 Table 50 – UBD none return valve

Features	Acceptance criteria	See
A. Description	The NRV is an insert type non-ported valve installed in a float sub that is run as an integral part of the work string to be used in an underbalanced operation. Although dimensionally similar to the drill pipe floats used in a conventional drilling operation, the NRV is required to meet more stringent specifications both in the materials used for manufacture and QA/QC of final product, to qualify its use as a UB WBE. The typical valve design can be either a dart/plunger type, or a flapper type.	
B. Function	The NRV functions as the primary down-hole WBE within the work string to provide positive and instantaneous shut off against high or low pressure and prevent fluid flow to surface from below the valve. The primary purpose of NRVs located in the BHA assembly is for well control. These valves are also installed higher up in the work string when injecting a gaseous drilling fluid down the work string. Its functional requirement is the same but its purpose in this instance is purely economic; that is to minimise the amount of gas and time required for bleed off prior to making a connection.	
C. Design, construction and selection	1. The NRV float sub shall at a minimum meet the burst and collapse and torsion design criteria for the work string of which it is an integral component. The ability to positively lock the NRV in place shall be inherent in the design of the float sub. 2. The selected NRV shall be fit for purpose to operate as designed within the expected operating pressure envelope. 3. The NRV shall by design be capable of withstanding vibration, shock loads, and exposure to a solids environment without failure of the sealing mechanisms. 4. Working pressure rating of the selected NRV shall at a minimum be equal to the maximum expected differential pressure the NRV will be exposed to. 5. The sealing elements of the selected NRV shall be compatible with the operating fluid environment (liquid, gas and multiphase) expected and the expected operating temperature envelope.	NORSOK D-002 other valid NRV specifications Specific to elastomer testing ASTM D412 ASTM D471 ASTM G111 ASTM D2240
D. Initial test and verification	1. The NRV shall prior to delivery pass a documented differential pressure test to 3,5 MPa for 5 min and to the WP rating for 10 min with a gas medium and shall not leak. Testing shall be in the direction of flow. 2. Material certificates for the NRV and components shall be available. 3. After initial installation, pressure integrity of the NRV as a working well barrier shall be verified by inflow testing during connections. 4. After redressing an NRV on location, the NRV assembly shall be leak tested to the maximum expected differential pressure the NRV will be exposed to using water. Only manufacturer's original equipment with the same specifications will be acceptable for redressing. Testing shall be in the direction of flow.	
E. Use	The work string above the NRV should be fluid filled while RIH. Sudden quick starting and stopping of the circulation system pumps should be avoided.	
F. Monitoring	Inflow tests during connections.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Debris across the NRV will prevent proper closure and cause damage to the valve. The use of drill pipe screens is recommended.	

Annex A
(Normative)
Leak test pressures and frequency for well control equipment

Table A.1 - Routine leak testing of drilling BOP and well control equipment

	Frequency / Element	Stump	Before drilling out of casing		Before well testing	Periodic		
			Surface	Deeper casing and liners		Weekly	Each 14 days	Each 6 months
BOP	Annulars	MWDP 1)	Function	MSDP 1)	TSTP 1)	Function	MSDP 1)	WP x 0,7
	Pipe rams	MWDP	Function	MSDP	TSTP	Function	MSDP	WP
	Shear rams	MWDP	Function	MSDP	TSTP	Function		WP
	Failsafe valves	MWDP	Function	MSDP 3)	TSTP	Function	MSDP 3)	WP
	Well head connector	MWDP	MSDP		TSTP		MSDP	WP
	Wedge locks	Function						
Choke/kill line and manifold	Choke/kill lines	MWDP	MSDP	MSDP	TSTP		MSDP	WP
	manifold	MWDP	MSDP	MSDP	TSTP		MSDP	WP
	Valves	Function	Function	Function	Function		Function	
	Remote chokes							
Other equipment	Kill pump	WP 2)		MSDP			MSDP	WP
	Inside BOP	MWDP 2)		MSDP	TSTP		MSDP	WP
	Stabbing valves	MWDP 2)		MSDP	TSTP		MSDP	WP
	Upper kelly valve	MWDP 2)		MSDP			MSDP	WP
	Lower kelly valve	MWDP 2)		MSDP			MSDP	WP

Legend

WP	working pressure
MWDP	maximum well design pressure
MSDP	maximum section design pressure
Function	Function testing: testing shall be done from alternating panels/pods.
TSTP	tubing string test pressure
1)	Or maximum 70 % of WP
2)	Or at initial installation
3)	From above if restricted by BOP arrangement

NOTE 1 All tests shall be 1,5 MPa to 2 MPa/5 min and high pressure/10 min.

NOTE 2 If the drilling BOP is disconnected/re-connected or moved between wells without having been disconnected from its control system, the initial leak test of the BOP components can be omitted. The wellhead connector shall be leak tested.

NOTE 3 The BOP with associated valves and other pressure control equipment on the facility shall be subjected to a complete overhaul and shall be recertified every five years. The complete overhaul shall be documented.

Table A.2 - Failure of drilling BOP and control systems

Barrier element/equipment	Actions to be taken when failure to test
Annular	Repair immediately.
Shear ram	If WBE, repair immediately.
Pipe ram (upper, middle, lower)	If WBE, repair immediately if no other pipe rams is available for that pipe size. Rams that failed to test to be repaired at a convenient time.
Choke valves, inner/outer Kill valves, inner/outer	If both valves in series have failed, repair immediately. If one valve in series has failed, repair after having set casing.
Marine riser choke and kill line *	If one has failed, repair immediately.
Yellow and blue pod *	If both have failed, repair immediately. If one has failed, repair at a convenient time.
Acoustic – shear ram *	Same as for shear ram.
Acoustic – pipe rams *	If one or more have failed, repair after having set casing if size is covered by another ram. If not, repair immediately.
*** floating installations** **Nomenclature :**	*Immediately:* Stop operation and temporary abandon well. *After having set casing:* Carry on with the operation and repair after having set the next casing. *Convenient time:* Applicable for WBEs that are not required.

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