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**Well integrity —**

Part 2:

**Well integrity for the operational phase**

*Titre manque*

**PROOF / ÉPREUVE**

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## Foreword

ISO (the International Organization for Standardization) is a worldwide federation of national standards bodies (ISO member bodies). The work of preparing International Standards is normally carried out through ISO technical committees. Each member body interested in a subject for which a technical committee has been established has the right to be represented on that committee. International organizations, governmental and non-governmental, in liaison with ISO, also take part in the work. ISO collaborates closely with the International Electrotechnical Commission (IEC) on all matters of electrotechnical standardization.

International Standards are drafted in accordance with the rules given in the ISO/IEC Directives, Part 2.

The main task of technical committees is to prepare International Standards. Draft International Standards adopted by the technical committees are circulated to the member bodies for voting. Publication as an International Standard requires approval by at least 75 % of the member bodies casting a vote.

In other circumstances, particularly when there is an urgent market requirement for such documents, a technical committee may decide to publish other types of normative document:

- an ISO Publicly Available Specification (ISO/PAS) represents an agreement between technical experts in an ISO working group and is accepted for publication if it is approved by more than 50 % of the members of the parent committee casting a vote;
- an ISO Technical Specification (ISO/TS) represents an agreement between the members of a technical committee and is accepted for publication if it is approved by 2/3 of the members of the committee casting a vote.

An ISO/PAS or ISO/TS is reviewed after three years in order to decide whether it will be confirmed for a further three years, revised to become an International Standard, or withdrawn. If the ISO/PAS or ISO/TS is confirmed, it is reviewed again after a further three years, at which time it must either be transformed into an International Standard or be withdrawn.

Attention is drawn to the possibility that some of the elements of this document may be the subject of patent rights. ISO shall not be held responsible for identifying any or all such patent rights.

ISO/TS 16530-2 was prepared by Technical Committee ISO/TC 67, *Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries*, Subcommittee SC 4, *Drilling and production equipment*.

ISO/TS 16530 consists of the following parts, under the general title *Petroleum and natural gas industries — Well integrity*:

- *Part 1: Life cycle governance manual*
- *Part 2: Well integrity for the operational phase*

## Introduction

This Technical Specification has been developed by producing operating companies for oil and gas, and is intended for use in the petroleum and natural gas industry worldwide. This Technical Specification is intended to give requirements and information to the Well Operator on managing well integrity for the operational phase. Furthermore, this Technical Specification addresses the minimum compliance requirements for the Well Operator, in order to claim conformity with this Technical Specification.

It is necessary that users of this Technical Specification are aware that requirements above those outlined in this Technical Specification can be needed for individual applications. This Technical Specification is not intended to inhibit or replace legal requirements; it is in addition to the legal requirements; where there is a conflict the legal requirement always takes precedence. This can be particularly applicable where there is innovative or developing technology, with changes in field or well design operating philosophy.

This Technical Specification addresses the process of managing well integrity by assuring compliance to the specified operating limits for identified well types, that are defined based on exposure of risk to people, environment, assets and reputation, supported by associated well maintenance/monitoring plans, technical reviews and management of change.

The following terminology is used in this Technical Specification.

- a) The term “**shall**” or “must” denotes a minimum requirement in order to conform to this Technical Specification.
- b) The term “should” denotes a recommendation or that which is advised but not required in order to conform to this Technical Specification.
- c) The term “may” is used to indicate a course of action permissible within the limits of the document.
- d) The term “consider” is used to indicate a suggestion or to advise.
- e) The term “can” is used to express possibility or capability.



## Well integrity —

### Part 2:

## Well integrity for the operational phase

**IMPORTANT** — The electronic file of this document contains colours which are considered to be useful for the correct understanding of the document. Users should therefore consider printing this document using a colour printer.

### 1 Scope

This Technical Specification provides requirements and methods to the oil and gas industry to manage well integrity during the well operational phase.

The operational phase is considered to extend from handover of the well after construction, to handover prior to abandonment. This represents only the period during the life cycle of the well when it is being operated and is illustrated in [Figure 1](#).

The scope of the Technical Specification includes:

- A description of the processes required to assess and manage risk within a defined framework. The risk assessment process also applies when deviating from this Technical Specification.
- The process of managing well integrity by operating wells in compliance with operating limits for all well types that are defined based on exposure of risk to people, environment, assets and reputation. The management of well integrity is supported by associated maintenance/monitoring plans, technical reviews and the management of change.
- The assessment of existing assets (wells / fields) in order to start the process of Well Integrity Management in accordance with this technical specification.
- The handover process required when changing from one activity to another during the operational phase.

The scope of the Technical Specification applies to all wells that are utilized by the oil and gas industry, regardless of their age, type or location.

The scope of the Technical Specification does NOT apply to:

- The periods during well intervention or work-over activities but it DOES include the result of the intervention and any impact that this can have to the well envelope and the associated well barriers.
- The equipment that is required or used outside the well envelope for a well intervention such as wire-line or coiled tubing or a pumping package.

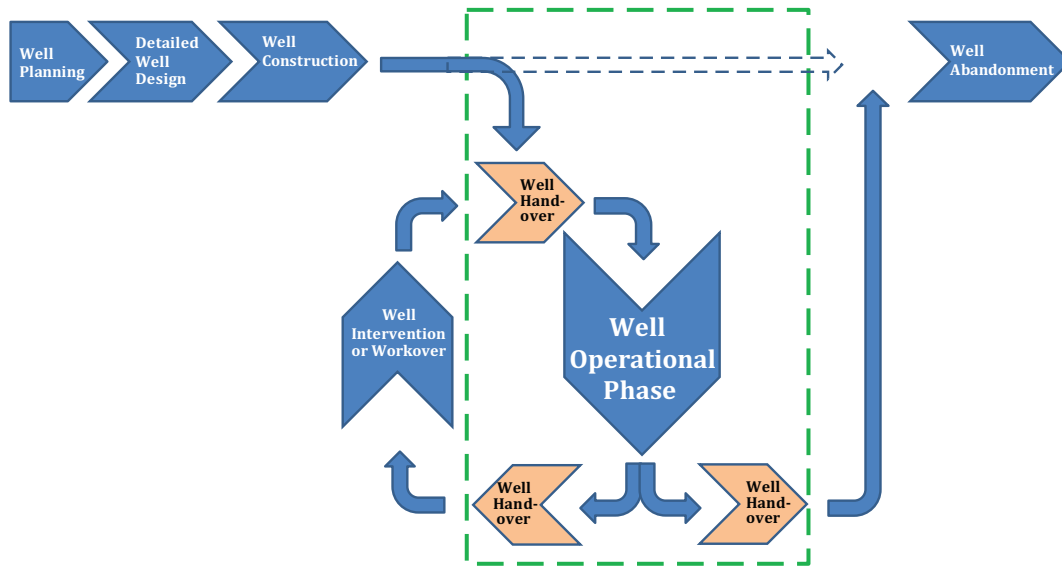


Figure 1 — Illustration of the scope of this Technical Specification

## 2 Normative references

The following documents, in whole or in part, are normatively referenced in this document and are indispensable for its application. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

ISO 10417:2004, *Petroleum and natural gas industries — Subsurface safety valve systems — Design, installation, operation and redress*

API RP 14H, *Recommended Practice for Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore, Fifth Edition*

## 3 Terms, definitions and abbreviated terms

For the purposes of this document, the following terms and definitions apply.

### 3.1

#### **A-annulus**

designation of annulus between the production tubing and production casing

[SOURCE: API RP 90, modified]

### 3.2

#### **abandoned well**

permanent subsurface isolation of the well

### 3.3

#### **ambient pressure**

pressure external to the wellhead

Note 1 to entry: In the case of a surface wellhead, the pressure is zero psig. In the case of a subsea wellhead, it is equal to the hydrostatic pressure of seawater at the depth of the subsea wellhead, in psig.

[SOURCE: API RP 90, modified]

**3.4****anomaly**

condition that differs from what is expected or typical, or which differs from that predicted by a theoretical model

**3.5****B-annulus**

designation of annulus between the production casing and the next outer casing

Note 1 to entry: The letter designation continues in sequence for each outer annular space encountered between casing strings, up to and including the surface casing and conductor casing strings.

[SOURCE: API RP 90, modified]

**3.6****breaking of containment**

breaking into the containment system of integrity or barrier envelope

**3.7****competency**

ability of an individual to perform a job properly through a combination of training, demonstrated skills and accumulated experience

**3.8****component**

mechanical part, including cement, used in the construction of a well

**3.9****conductor casing**

element that provides structural support for the well, wellhead and completion equipment, and often for hole stability for initial drilling operations

Note 1 to entry: This casing string is not designed for pressure containment, but upon completion of the well, it may have a casing head; therefore, it can be capable of containing low annular pressures. For subsea and hybrid wells, the low pressure subsea wellhead is normally installed on this casing string.

[SOURCE: API RP 90, modified]

**3.10****consequence**

expected effect of an event that occurs

**3.11****deep-set**

below or close to the production packer, or at the cap rock of a reservoir to isolate the production tubing or casing from the producing reservoir

**3.12****deviation**

departure from a standard

**3.13****double-block and bleed principle**

operation with two valves or seals, in series, or a valve and a blind cap in all relevant, utilized flow paths into and out of the well that are not connected to a closed system

**3.14****failure**

loss of intended function

**3.15**

**failure mode**

description of the method of failure

**3.16**

**failure modes and effects analysis**

**FMEA**

procedure used in design, development and operations management for the analysis of potential failure modes within a system for classification of the severity and likelihood of the failures

**3.17**

**failure mode, effects, and criticality analysis**

**FMECA**

extension of FMEA (3.16) that in addition includes an analysis of the criticalities to evaluate the seriousness of the consequences of a failure versus the probability of its occurrence

**3.18**

**fault**

abnormal, undesirable state of a system element (e.g. entire subsystem, assembly, component) induced by the presence of an improper command or absence of a proper one, or by a failure

Note 1 to entry: All failures cause faults, not all faults are caused by failure.

**3.19**

**flow-wetted**

any surface that is exposed to fluids coming from a pressure source for that fluid

**3.20**

**handover**

act or process of transferring responsibility for operating a well from one competent party to another, including both custody to operate (certificate) and the requisite data and documents which describe the well construction

**3.21**

**hazard**

source of potential harm or a situation with a potential to cause loss (any negative consequence)

[SOURCE: API RP 90, modified]

**3.22**

**hybrid well**

well drilled with a subsea wellhead and completed with a surface casing head, a surface tubing head, a surface tubing hanger, and a surface Christmas tree

Note 1 to entry: A hybrid well can have either one (single-bore production riser) casing string or two (dual-bore production riser) casing strings brought up from the subsea wellhead and tied back to the surface equipment. These wells are typically located on floating production platforms, such as spars or TLPs.

[SOURCE: API RP 90, modified]

**3.23**

**impairment**

state of diminished ability to perform a function, but not yet failed

**3.24**

**inflow testing**

use of the tubing or casing pressure to perform leak testing

**3.25**

**intervention**

operation to enter the well through the Christmas tree

**3.26****leak**

unintended and, therefore, undesired movement of fluids, either to or from, a container or a fluid containing system

**3.27****casing/liner**

casing string with its uppermost point inside and near the bottom end of a previous casing string using a liner hanger

**3.28****major hazard**

hazard (3.21) with a potential for causing major accidents, i.e. involving fatality due to fire or explosion, major pollution, multiple fatalities, or severe damage to the installation

**3.29****maximum allowable annulus surface pressure****MAASP** **$P_{MAASP}$** 

greatest pressure that an annulus can contain, as measured at the wellhead, without compromising the integrity of any element of that annulus, including any exposed open-hole formations

**3.30****the operational phase**

is considered to extend from handover of the well after construction, to handover prior to abandonment, indicating the life cycle of the well while being operated

**3.31****Well Operator-imposed annulus pressure**

casing pressure that is Well Operator-imposed for purposes such as gas lift, water injection, thermal insulation, etc

[SOURCE: API RP 90, modified]

**3.32****performance standard**

statement, which can be expressed in qualitative or quantitative terms as appropriate, of the performance required of a safety-critical element in order to ensure the safety and integrity of the installation

**3.33****pressure test**

application of a pressure from an external source (non-reservoir pressure) to ascertain the mechanical and sealing integrity of a component

**3.34****primary well barrier**

first well barrier envelope that the produced and/or injected fluids contact and that is in-place and functional during well operations

**3.35****production casing**

innermost string of casing in the well

Note 1 to entry: Production fluids enter the casing below the production packer and continue to the surface through the production string. At a minimum, the production casing is rated for the maximum anticipated pressure that can be encountered from the production zone.

[SOURCE: API RP 90, modified]

**3.36**

**production riser**

on fixed platforms, the casing strings rising from the seafloor to the wellhead or, on hybrid wells, the casing strings attached to the subsea wellhead rising from the seafloor to the surface wellhead

[SOURCE: API RP 90, modified]

**3.37**

**production string  
completion string**

string consisting primarily of production tubing, but also including additional components such as the surface-controlled subsurface safety valve (SCSSV), gas lift mandrels, chemical injection and instrument ports, landing nipples, and packer or packer seal assemblies

Note 1 to entry: The production string is run inside the production casing and used to conduct production fluids to the surface.

[SOURCE: API RP 90, modified]

**3.38**

**production tubing**

tubing that is run inside the production casing and used to convey produced fluids from the hydrocarbon-bearing formation to the surface

Note 1 to entry: Tubing can also be used for injection. In some hybrid wells, for example, tubing is used as a conduit for gas for artificial lift below a mudline pack-off tubing hanger to isolate the gas-lift pressure from the production riser.

[SOURCE: API RP 90, modified]

**3.39**

**reliability**

probability that equipment can perform a specified function under stated conditions for a given period of time

**3.40**

**risk**

combination of the consequences of an event and the associated likelihood of its occurrence

**3.41**

**risk assessment**

systematic analysis of the risks from activities and a rational evaluation of their significance by comparison against predetermined standards, target risk levels or other risk criteria

Note 1 to entry: Risk assessment is used to determine risk management priorities.

**3.42**

**safety critical element**

part of the installation or plant that is essential to maintain the safety and integrity of the installation

Note 1 to entry: This includes any item that is intended to prevent or limit the effect of a major hazard or which, upon failure, can cause or contribute substantially to a major hazard affecting the safety or integrity of the installation.

Note 2 to entry: Safety-critical elements include measures for prevention, detection, control and mitigation (including personnel protection) of hazards.

Note 3 to entry: Within the context of this Technical Specification, an installation is considered as a well.

**3.43**

**secondary well barrier**

second set of barrier elements that prevent flow from a source

[SOURCE: API RP 90, modified]

**3.44****shut-in well**

well with one or more valve(s) closed in the direction of flow

**3.45****subsea well**

well completed with a subsea wellhead and a subsea tree

[SOURCE: API RP 90, modified]

**3.46****subsea wellhead**

wellhead that is installed at or near the seabed

**3.47****surface casing**

casing that is run inside the conductor casing to protect shallow water zones and weaker formations and may be cemented within the conductor string and is often cemented back to the mud-line or surface

Note 1 to entry: The surface wellhead is normally installed on this string for surface wells.

[SOURCE: API RP 90]

**3.48****suspended well**

well that has been isolated from the producing reservoir via a deep-set down-hole isolation device (mechanical or cement plug)

Note 1 to entry: Components above the isolation device are no longer considered flow wetted.

**3.49****sustained annulus pressure (SAP)**

pressure in an annulus that

- a) rebuilds when bled down;
- b) is not caused solely by temperature fluctuations; and
- c) is not a pressure that has been imposed by the Well Operator

[SOURCE: API RP 90, modified]

**3.50****thermally induced annulus pressure**

pressure in an annulus generated by thermal expansion or contraction of trapped fluids

[SOURCE: API RP 90, modified]

**3.51****verification**

examination, testing, audit or review to confirm that an activity, product or service is in accordance with specified requirements

**3.52****well barrier element**

one or several dependent components that are combined to form a barrier envelope that, in combination, prevent uncontrolled flow of fluids within or from a well

**3.53****well barrier envelope**

combination of one or several well barrier elements that together constitute a method of containment of fluids within a well that prevent uncontrolled flow of fluids within, or out of, a well

**3.54**

**well integrity**

containment and the prevention of the escape of fluids (i.e. liquids or gases) to subterranean formations or surface

**3.55**

**well integrity management**

See [5.1](#)

**3.56**

**well inventory**

portfolio of wells that are not abandoned

**3.57**

**Well Operator**

company that has responsibility for operating the well

**3.58**

**well operational phase**

portion of the well's life cycle starting at the handover of the well after construction, until the well's permanent abandonment

Note 1 to entry: This includes production, injection, observation, closed-in and suspended well statuses.

Note 2 to entry: Well intervention activities, either rig based or rig-less, that involve breaking containment at the Christmas tree or wellhead are not part of the well operational phase.

**3.59**

**well operating limits**

combination of criteria that are established by the Well Operator to determine acceptable well integrity performance for the well's life

**3.60**

**well status**

well's current operational function i.e. flowing, closed in, suspended, undergoing construction or abandoned

## 4 Abbreviated terms

ALARP	as low as reasonably practicable
API	American Petroleum Institute
ASV	annulus safety valve
BOP	blow out preventer
BS&W	base sediment & water
DASF	drilling adaptor spool flange
DHSV	Down-hole safety valve
ESD	emergency shut-down
EVP	emergency valve pilot
FMEA	failure modes and effects analysis
FMECA	failure-mode and effects and criticality analysis

a NORSOK standards are developed by the Norwegian petroleum industry to ensure adequate safety, value adding and cost effectiveness for petroleum industry developments and operations.

FS	formation strength
BOP	annulus safety valve
BS&W	blow out preventer
ID	internal diameter
KPI	key performance indicator
MAASP	maximum allowable annular surface pressure
MOC	management of change
NORSOK	Norsk Søkkel Konkurransesjona
NPT	national pipe thread
OCP	observed casing pressure
OD	outer diameter
OEM	original equipment manufacturer
QRA	quantifiable risk assessment
RACI	responsible/accountable/consulted/informed
ID	internal diameter
KPI	key performance indicator
MAASP	maximum allowable annular surface pressure
MOC	management of change
ROV	remotely-operated vehicle
SCE	safety critical element
SAP	sustained annulus pressure
SF	safety factor
SCSSV	surface controlled sub-surface safety valve
SSCSV	sub-surface controlled subsurface safety valve
SSSV	sub surface safety valve
SSV	surface safety valve
TOC	top of cement
WBE	well barrier element
WIMS	well integrity management system
WOE	well operating limits

a NORSOK standards are developed by the Norwegian petroleum industry to ensure adequate safety, value adding and cost effectiveness for petroleum industry developments and operations.

## 5 Well integrity management system

### 5.1 Well integrity management

The management of well integrity is a combination of technical, operational and organizational processes to ensure a well's integrity during the operating life cycle.

### 5.2 Well integrity management system

The Well Operator **shall** have an approved well integrity management system (WIMS) that is applied to all wells under their responsibility, i.e. the well inventory.

As a minimum, the following elements **shall** be addressed:

- a) well integrity policy and strategy;
- b) resources, roles, responsibilities and authority levels;
- c) risk assessment aspects of well integrity management;
- d) well barriers;
- e) well component performance standards;
- f) well operating limits;
- g) well monitoring and surveillance;
- h) annular pressure management;
- i) well handover;
- j) well maintenance;
- k) well integrity failure management;
- l) management of change;
- m) well records and well integrity reporting;
- n) performance monitoring of well integrity management systems;
- o) compliance audit.

## 6 Well integrity policy and strategy

### 6.1 Well integrity policy

The Well Operator **shall** have a policy defining its commitments and obligations to safeguard health, environment, assets and reputation by establishing and preserving well integrity. This well integrity policy **shall** be endorsed at a senior level within the Well Operator organization.

The Well Operator well integrity management system (WIMS) **shall** clearly indicate how the policy is interpreted and applied to well integrity.

### 6.2 Well integrity strategy

The Well Operator **shall** define the high level strategic measures to which it is committing in order to achieve the requirements of the asset (well) integrity policy.

Such strategic measures may include an outline of how the Well Operator establishes

- business plans and priorities,
- resourcing plans, and
- budgeting

in support of its well integrity management objectives.

This high-level strategy **shall** manifest itself in, and be consistent with, the body of the well integrity management system (WIMS).

## 7 Resources, roles, responsibilities and authority levels

### 7.1 Organizational structure

Each Well Operator **shall** ensure that sufficient resources in their organization are available to manage well integrity effectively during the operational life cycle of the Well Operator entire well inventory.

Each Well Operator **shall** define the roles and responsibilities for all professional, supervisory, operational and maintenance personnel required to manage the well integrity system. Roles and responsibilities should be documented, for example in an RACI matrix (see [Annex A](#)).

The Well Operator **shall** assign the role of a well integrity technical authority / subject matter expert positioned outside of operations line management, to provide an independent technical review and recommendations on well integrity issues.

### 7.2 Competency

Each Well Operator **shall** ensure that their personnel (employees and contract) who participate in well integrity activities are competent to perform the tasks assigned to them.

Each Well Operator **shall** define well integrity personnel competency requirements to ensure that well integrity activities are carried out in a manner which is both safe and efficient as regards protection of health, the environment and assets. A competence performance record should be maintained that demonstrates compliance.

NOTE Competency can be gained through a combination of; education, training programmes, mentoring, self-study and on-the-job training (transfer of experience/expertise).

An example of a competency matrix is given in [Annex B](#).

## 8 Risk assessment aspects of well integrity management

### 8.1 General

[Clause 8](#) discusses how established and proven risk assessment techniques are applied and used as a tool to assist in the management of well integrity. It identifies factors that should be considered and introduces evaluation techniques that may be applied when using risk assessment as the basis for

- establishing monitoring, surveillance and maintenance regimes for well barrier elements that are aimed at minimizing the potential risks of any impairment to well barrier envelopes;
- determining which of the barrier elements are considered safety critical elements that require performance standards and assurance tasks that confirm compliance to the performance standard;
- determining an appropriate course of action to address any well anomalies that are encountered during these monitoring, surveillance and maintenance regimes;

- establishing risk of loss of containment considering, well type, pressure, effluent, outflow potential, location, environment against barrier redundancy.

## 8.2 Risk assessment considerations for well integrity

In 8.2.1 to 8.2.5 are given the minimum considerations that should be accounted for when assessing risks associated with well integrity in the operational phase.

### 8.2.1 Location

8.2.1.1 The well location can have a bearing on the risks presented by a well in terms of

- geographical location, e.g. onshore or offshore, urban or remote,
- facility/well type, e.g. platform, subsea, manned or unmanned facility/location,
- well concentration, e.g. single well, multiple well cluster.

8.2.1.2 Consideration should be given to the following:

- proximity of the well to workers and the potential effects on worker health and safety of any impairment to a well barrier envelope posed by any anomaly;
- proximity of the well to the environment and the potential effects on the environment of any impairment to a well barrier envelope posed by any anomaly;
- proximity of the well to other wells and infrastructure and the potential effects on such wells and infrastructure of any impairment to a well barrier envelope posed by any anomaly;
- assessment of any compounded risk posed by adjacent wells or infrastructure also having some form of impairment of their own barrier envelopes;
- societal impacts of any impairment to the well barrier envelope posed by an anomaly; consideration of such impacts should capture not only health, safety and environmental considerations to society at large, but also any economic impacts to society at large;
- ability to access the well in order to
  - monitor its condition,
  - perform maintenance,
  - perform repairs;
- ability to access the area in the vicinity of the well in order to mitigate the effects of any potential loss of integrity;
- ability and time to drill a relief well, if required.

### 8.2.2 Outflow potential

The ability of the well fluids to flow to the surface or into an undesirable subsurface location within the wellbore, with or without the aid of artificial lift, potentially has a bearing on the magnitude of the consequences associated with a loss of well integrity.

Consideration should be given to the impacts of the following:

- potential sources and leak-paths for outflow (tubing, annulus, control lines, gas-lift valves);
- outflow medium (from reservoirs and also limited volumes, e.g. gas lift gas);

- failure of other barrier elements;
- rates;
- volumes;
- pressures;
- temperatures;
- duration over which the well is able to sustain flow;
- effects from offset wells, e.g. the effect that an offset injection well has on sustaining reservoir pressure support to a producer to enhance its ability to flow.

### 8.2.3 Well effluent

The composition of the well stream has a bearing on the risks posed by any well, both in terms of the effects of well effluent on impairment of the well barrier envelopes and the health, safety, environmental and societal risks associated with potential discharge of these effluents in the event of a loss of well integrity.

The effects of following fluid components within the well stream composition should be considered in a risk assessment associated with any potential anomaly:

- sour components;
- corrosive components;
- poisonous components;
- carcinogenic components;
- flammable or explosive components;
- erosive components;
- asphyxiating components;
- compatibility between components;
- formation of emulsion, scale, wax and hydrate deposits.

### 8.2.4 External environment

#### 8.2.4.1 External risk to consider

In addition to well integrity risks influenced by outflow potential and well effluents, there are potential well integrity risks posed by exposure of well barriers to external environments that can be unrelated to the production or injection intervals to which these wells are connected.

The following effects should be considered:

- external corrosion of structural components such as conductor casing, surface casing and wellhead exposed to the atmosphere (i.e. due exposure to weather);
- external corrosion of structural components such as conductor, surface casing and wellhead exposed to the marine environment;
- external corrosion of casing strings exposed to corrosive fluids in subsurface locations (e.g. aquifers containing corrosive fluids, incompatibility between annulus fluid and top up fluid, corrosive top up fluid);

- fatigue of structural components due to cyclic loading (e.g. motion of wellheads, conductors, tie-back casing strings, etc. due to the action of waves and currents offshore, wellhead motion due to interactions between loads imposed by BOPs/risers and wellheads during any drilling or work-over activities);
- impact of cyclic and/or thermal loading of wells on soil strength and the ability of soils to provide structural support to the well;
- external loads on wells associated with earth movements (e.g. reservoir compaction, earthquakes, tectonic motion associated with faults and motion of ductile materials such as salt formations);
- mechanical impacts associated with dropped objects (from facilities, vessels, vehicles or other equipment in the proximity of the wells);
- mechanical impacts associated with collisions (e.g. by ships or vehicles).

#### 8.2.4.2 External risk mitigations

Some examples of risk and mitigations due external risk:

- subsea wells:
  - risk identified: collision with fishing trawlers' anchor chains/nets,
  - mitigation: deflector installed on subsea wellhead;
- offshore wells:
  - risk identified: dropped objects, drilling BOP of cantilever rig,
  - mitigation: weather deck above wellheads provided with a drop load capability;
- onshore wells:
  - risk identified: collision impact with moving vehicle,
  - mitigation: impact barriers placed around wellhead.

#### 8.2.5 Redundant systems

Redundant systems constitute the components within the well that provide additional safeguards to mitigate potential impairments to well barrier envelopes.

Consideration should be given to the following when assessing how a redundant system affects well integrity risks:

- extent to which the redundant systems can be operated independently of a system that could be impaired;
- response time of redundant systems;
- service conditions for which the redundant systems are designed, relative to those of the system that can be impaired;
- method of operation of the redundant systems, e.g. manual or automatic.

Examples of redundant systems include an outer annulus (if rated), additional inline valves and additional ESD systems.

### 8.3 Risk assessment techniques

Risk assessment techniques are used to assess the magnitude of well integrity risks whether these are potential risks, based on an assessment of possible failure modes, or actual risks, based on an assessment of an anomaly that has been identified.

Different types of techniques may be applied as deemed appropriate by the Well Operator for the particular well integrity issue that it is necessary to assess. A risk assessment process typically involves

- identification of the types of well anomaly and failure-related events that are possible for the well(s) that are being assessed;
- determination of the potential consequences of each type of well failure-related event; the consequences can be to health, safety, environmental or societal or a combination of these factors;
- determination of the likelihood of occurrence of the event;
- determination of the magnitude of the risk of each type of well failure-related event based on the combined effect of consequence and likelihood.

The assessment of any well failure-related event is normally depicted on a risk assessment matrix (an example of a “5 by 5” matrix is given in [Figure 2](#)) such that risk can be categorized or ranked based on the combined effects of consequence and likelihood of occurrence.

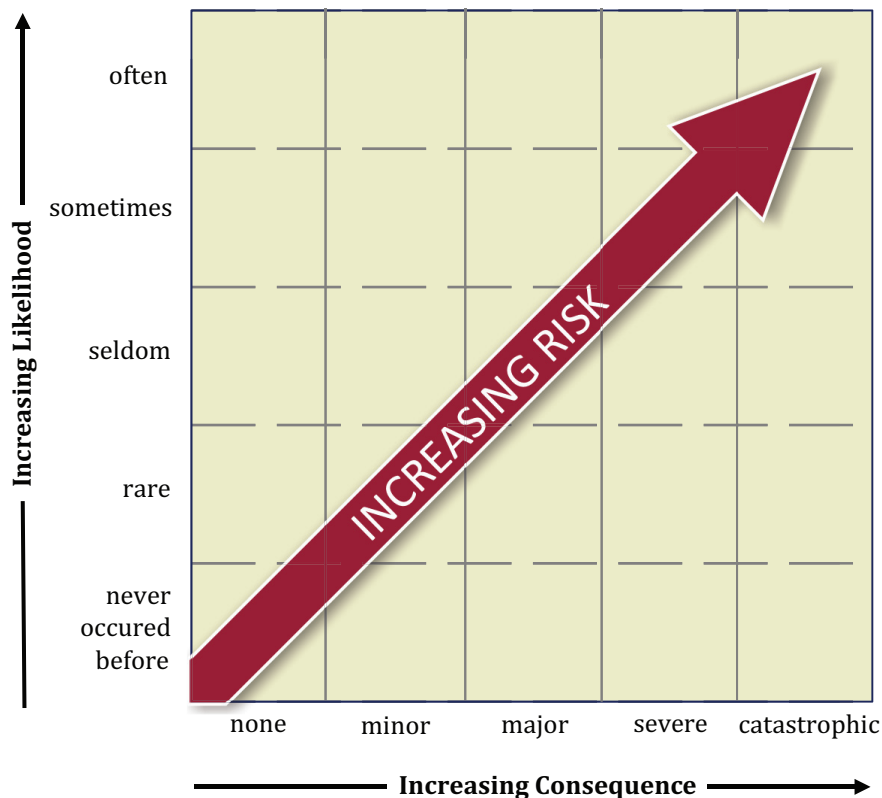


Figure 2 — Example of a Risk assessment matrix (RAM)

The Well Operator **shall** determine

- appropriate levels/definitions for consequence (severity) and likelihood of occurrence (probability) categories on the risk assessment matrix axes (simple examples of categories are shown in [Figure 2](#)); increasing levels of consequence and/or likelihood reflect increasing levels of risk (higher risk rankings);
- appropriate levels/definitions for the risk regions (boxes) within the risk assessment matrix.

A qualitative risk assessment may be used where the determination of both consequence and likelihood of occurrence is largely based on the judgement of qualified and competent personnel based on their experience.

Quantifiable risk assessment (QRA) is another technique that may be applied to assess well integrity risks. This technique also assesses both consequence and probability but uses information from databases on well integrity failures to quantify the probability of a given event occurring.

Failure-mode and effects and criticality analysis (FMECA) can also be used to determine well integrity risks. FMECA is particularly useful in establishing the types of component failures that can occur, the effect on the well barrier envelope(s) and the likelihood of such failures occurring. This information can then be used to assist design improvements and in establishing the type and frequency of monitoring, surveillance and maintenance required to reduce the risk of the failures modes identified as part of the FMECA.

Detailed risk assessment methods and techniques can be found in ISO 17776, ISO 31000 and ISO/IEC 31010.

### 8.4 Application of risk assessment in establishing monitoring, surveillance and maintenance requirements

Monitoring, surveillance and maintenance techniques for wells are described in [Clauses 14](#) and [15](#). The determination of appropriate techniques, including the required frequencies at which these techniques are applied, should ideally be supported by an assessment of the well integrity risks.

The risk assessment normally involves following the processes described in [8.3](#) to identify and rank the risks from potential well failure-related events.

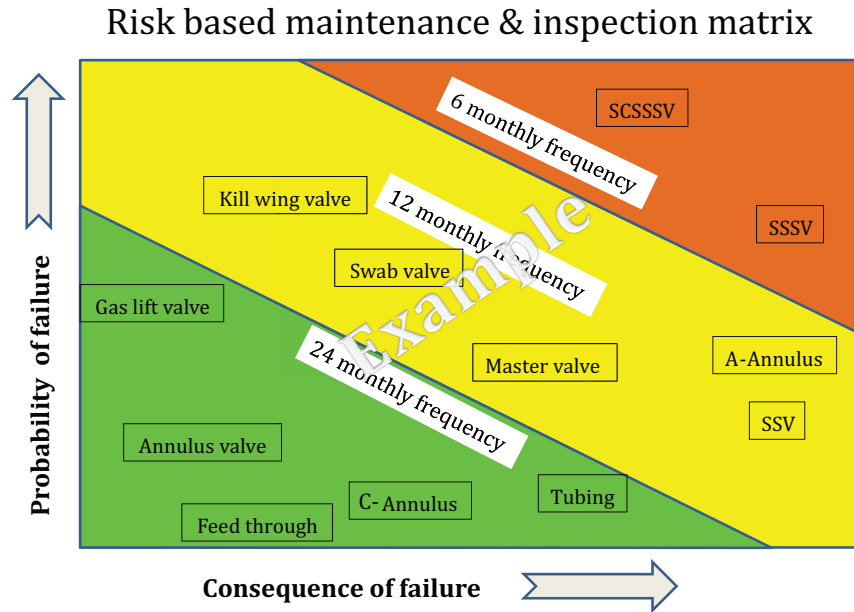
The risk assessment is used to help establish

- types and frequency of monitoring;
- types and frequency of surveillance;
- types and frequency of maintenance;
- appropriate verification test acceptance criteria.

Once these parameters are established, they are used to reduce the risks of the identified potential well failure related events to acceptable levels.

There should, therefore, be a clear linkage between the overall risk profile of any given well type and its monitoring, surveillance, maintenance and acceptance regime. This normally means that wells with higher risks of well failure related events require more frequent maintenance in order to reduce risk (see [Figure 3](#)).

It is necessary for the Well Operator, when using a risk-based approach, to map for each well type, the components that may require monitoring, surveillance and maintenance in a risk based model. The risk based model (see API RP 580 for risk-based inspection examples) is used to identify the magnitude of the risk presented by the failure of a single component (initially assuming no monitoring, surveillance or maintenance) and maps this risk on a risk assessment matrix. Once the risks for all components are mapped on the matrix, isometric lines (i.e. lines plotted on the matrix that represent the same level of risk) can then be used to help define appropriate monitoring, surveillance and maintenance frequencies, together with an acceptance regime for such activities, to mitigate the identified risks. [Figure 3](#) gives an example of a risk matrix used for this purpose.



**Figure 3 — Example of risk-based model as applied for well integrity assurance activities**

### 8.5 Application of risk assessment in the assessment of well integrity anomalies

If an anomaly has the potential to affect the defined operating limits of the well, the risks posed by such an anomaly should be assessed and addressed. The Well Operator may already have established the activities that it is necessary to implement to address the anomaly based on existing practices or procedures.

The following steps describe the typical process that should be followed to establish the well integrity risk.

- Identify the well integrity anomaly.
- Assess whether the anomaly poses potential risks from well failure-related events or can lead to further anomalies that pose such risks.
- Assess the consequences and likelihood of each risk.
- Assess the magnitude of each risk (equal to the product of the consequence and the likelihood) associated with each event, preferably using a risk assessment matrix.
- Assess what actions or activities can be implemented that mitigate or reduce each risk.
- Assess the consequence, likelihood and magnitude of each risk after implementation of mitigating actions or activities, preferably using a risk assessment matrix.
- Assess whether each residual risk (i.e. the magnitude of the risk after any risk mitigation/reduction measures are implemented) is tolerable enough to permit the well to remain operational.

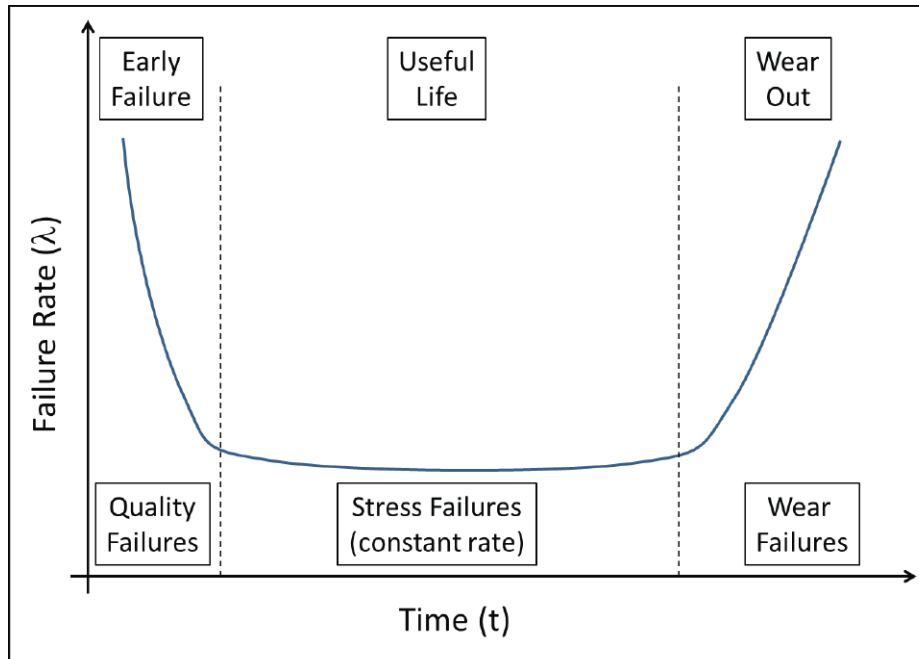
The magnitude of risk (prior to implementation of any risk reduction measures) should be used in determining the actions that are appropriate to address the anomaly. Generally, the higher the risk, the greater the priority and/or resources that are required, apply.

### 8.6 Failure rate trending

Trending of failure rates against time can also help to determine inspection frequencies for certain classes or models of equipment and can influence future replacement equipment selection.

The failure rate can also change depending on the age of the component; this is depicted in the curve in [Figure 4](#). This curve typifies the expected component failure rate across time and is divided into three distinct areas:

- early life (decreasing failure rate), when failures is due to component quality;
- useful life (constant failure rate), when failures is due to normal in-service stress;
- wear-out (increasing failure rate), when failures is due to component wear and tear.



**Figure 4 — Component failure rate as a function of time**

Quality failures (or early failures) are typically associated with design or fabrication error (e.g. faulty material, bad assembly, etc.). Wear-out failures are typically associated with such failure mechanisms as metal loss, thermal fatigue, creep, etc.

The period where the failure rate is constant is the period of the component’s useful life. During this period, a high confidence level can be applied to the component’s probable time to failure and appropriate service and replacement intervals determined.

## 9 Well barriers

### 9.1 General

Well barriers are the corner stone of managing well integrity. [Clause 9](#) discusses the well barriers, well barrier envelopes, well barrier elements, well barrier philosophy and how these are used by the Well Operator in their well integrity management system.

The primary purpose of well integrity management is to maintain full control of fluids at all times to prevent the loss of containment to the exterior of the wellbore, the environment and formations penetrated by the wellbore. This is achieved by employing and maintaining one or more well barrier envelopes.

### 9.2 Barrier philosophy

The Well Operator **shall** define a barrier philosophy for each of the well types within the WIMS.

An example of a well barrier philosophy is given below.

- If a well is capable of sustained flow to the surface or to an external environment due to reservoir pressure (natural or maintained), at least two independently tested well barrier envelopes should be maintained.
- If a well is not capable of natural flow to the surface, one (1) mechanical well barrier envelope may be maintained. This is based on the principle that the hydrostatic column of the wellbore fluids provides the primary barrier envelope itself. In these cases, a risk analysis should be performed to confirm that one mechanical barrier envelope is adequate to maintain containment, including subsurface flow.

### 9.2.1 Barriers when breaking containment

- A minimum of two barriers that can be independently verified are required prior to breaking containment for repairs.
- The allowable leak rate through the sum of these two barriers should be zero or bubble-tight. If there is a small leakage rate through one of these barriers, a double block-and-bleed system should be in place so that the pressure is constantly maintained at zero.

### 9.3 Well barrier envelopes

The preservation, maintenance, inspection and testing of well barrier envelopes are key aspects of the management of well integrity throughout the operational phase of a well.

The Well Operator **shall** know the status of each well barrier envelope and **shall** maintain all well barrier envelope(s) according to the well's intended well operating limits.

In cases where a barrier envelope cannot be maintained according to the original design specification, the Well Operator **shall** perform a risk assessment to establish the required controls to mitigate the risk.

During the operating phase of a well, boundary conditions or well usage may change. This requires a re-evaluation of the barrier envelopes and the well operating limits.

A well barrier envelope **shall**

- withstand the maximum anticipated differential pressures to which it can be subjected;
- be leak- and function-tested, or verified by other methods;
- function as intended in the environment (pressures, temperature, fluids, mechanical stresses) that can be encountered throughout its entire life cycle.

Once a well has been constructed and handed over for operation, the number of barrier envelopes will have been determined during the well's design and **shall** be documented through a well handover process.

### 9.4 Well barrier element

**9.4.1** A well barrier envelope may include mechanical well barrier elements.

For a well barrier element to be considered operational, it should be verified and maintained through regular testing and maintenance. The location and integrity status of each well barrier element should be known at all times (see [Annex C](#)).

**9.4.2** For a well in operation, the primary well barrier envelope typically constitutes the following well barrier elements:

- cap rock,

- casing cement,
- production casing,
- production packer,
- tubing
- SCSSV or Christmas tree master valve.

**9.4.3** The secondary well barrier typically constitutes the following well barrier elements:

- formation,
- casing cement,
- casing with hanger and seal assembly,
- wellhead with valves,
- tubing hanger with seals,
- Christmas tree and Christmas tree connection.
- actuated wing valve or Christmas tree master valve

NOTE The SSSV is considered to be a part of the primary barrier envelope in some jurisdictions.

## 9.5 Documenting of well barrier envelopes and well barrier elements

The Well Operator **shall** be able to demonstrate the status of well barrier envelopes for each well and well type.

The Well Operator should consider recording the current barrier envelopes and their respective elements. It is suggested that a well barrier schematic be used to convey this information. Any failed or impaired well barrier elements should be clearly marked and stated on the well barrier record.

It **shall** be clear from the well handover documentation which components in the well are well barrier elements and comprise which barrier envelope, the primary or the secondary (where applicable).

A sample of a well barrier schematic is presented in [Annex D](#).

## 10 Well component performance standard

### 10.1 General

A well component performance standard contains the functionality and acceptance criteria for each of the barrier safety critical elements. Acceptance criteria for well integrity describe such items as acceptable leak rates, time to closure, fail-safe specification; etc.

[Clause 10](#) describes the required performance standards for the well barrier envelopes and associated barrier elements. Additionally, the section provides examples and guidance, including calculations, for verification of the performance standard as specified by the Well Operator.

The Well Operator **shall** define performance standards for each well type. Performance standards, supported by the risk assessment, are the basis for the development of maintenance and monitoring requirements.

Items to consider when defining a performance standard are

- functionality;

- availability;
- reliability;
- survivability;
- failure mechanisms;
- failure consequences;
- operating conditions;
- interactions with other systems.

An example of a performance standard is to be found in [Annex E](#).

Well barrier elements, their functions and failure modes (see [Annex F](#)) can be used to aid in developing appropriate acceptance, monitoring and maintenance criteria; examples are described in a well integrity maintenance and monitoring model given in [Table 3](#).

## 10.2 Acceptance criteria and acceptable leak rates

A leak is defined as an unintended, and therefore undesired, movement of fluids either to, or from, a container or a fluid containing system.

Examples of well failure modes and leak paths are given in [Annex G](#).

Using a risk-based approach, the Well Operator should define their acceptable leak rates and testing frequency for individual barrier elements for all well types within the acceptance criteria described below.

The acceptable leak rate through individual well barrier elements can be different; for example, an SCSSV flapper valve may be allowed to have a higher leak rate than a Christmas tree master valve. These differing allowable leak rates are catalogued in a matrix, which is referred to as the “leak rate acceptance matrix” (see [Table 1](#)) and which can be included as part of a performance standard.

Acceptable leak rates **shall** satisfy at least all the following acceptance criteria:

- leak across a valve, leak contained within the envelope or flow path: ISO 10417:2004;
- leak across a barrier envelope, conduit to conduit: not permitted unless the receiving conduit is able to withstand the potential newly imposed load and fluid composition;
- no leak rate from conduit to conduit exceeding the leak rate specified in ISO 10417:2004, which defines an acceptable leak rate as 24 l/h of liquid or 25,4 M3/h (900 scf/h) of gas; NOTE: for the purposes of this provision, API RP 14B is equivalent to ISO 10417:2004.
- no unplanned or uncontrolled leak of wellbore effluents to the surface or subsurface environment.

Ingress of wellbore gas or wellbore effluent into a control, chemical injection, lines should be risk-assessed and mitigating measures put in place as determined by the assessment.


Planned leaks can occur at dynamic seals such as polished rod stuffing boxes or positive cavity pump rotary stuffing boxes. Where this type of leakage is expected to occur, mitigating measures shall be in place to capture and contain the effluent.

NOTE The inflow or leak testing of *in situ* gas lift valves is difficult to measure and compare to the ISO 10417:2004 leak rate. A description of how this can be rigorously performed together with a suggested practical alternative is included in [Annex H](#).

In the case of one or more unacceptable leak rates, the well the Well Operator **shall** risk assess the potential loss of containment and put mitigating controls in place as deemed necessary by the assessment. Operating outside a defined envelope should be managed by a formal risk based deviation system.

**Table 1 — Example of an acceptable leak rate matrix (not exhaustive)**

**Example: Acceptable leak rate matrix (not exhaustive)**

Acceptable leak rate matrix for: Operator: XYZ; Field: ABC Well Type: Producing wells Other: Closed in thp does not exceed 2,500 psi							
 Increasing allowable leak rate							
Operator should perform a risk based analysis to determine allowable leak rates for various barrier elements and for different well types.	Zero leak rate (bubble tight)		2cc/min per inch of valve size (0.5 l/h or 18 scf/h for 4-1/16" valve) (0.6 l/h or 23 scf/h for a 5-1/8" valve) (0.7 l/h or 29 scf/h for 6-3/8" valve)		10 l/h or 450 scf/h		Leakrate as defined in API 14B 24 l/h or 900 scf/h
	Hydraulic master valve (ESD)						
Lower master valve							
Hydraulic wing valve (ESD)							
Swab valve							
Kill wing valve							
Gas lift wing valve (ESD)							
Xmas tree body							
SSSV							
Tubing plug in suspended well							
Bonnets, flanges and fittings							
Stem packings							
Instrument lines							
Control lines							
Tubing void							
Xmas tree actuators & lines							
Wellhead voids							
A-Annulus valves (normally open)							
A-Annulus valves (normally closed)							
B-Annulus valves							
C-Annulus valves							
Installed VR plugs							
Tubing leak (sub hydrostatic well)							
Tubing leak (flowing well)							
Gas lift valves (sub hydrostatic well)							
Gas lift valves (flowing well)							
Production casing leak (sub hydrostatic well)							
Production casing leak (from 9-5/8" shoe)							
Intermediate casing leak							
Production packer							

### 10.3 Measuring the leak rate

Direct measurement of a leak rate is often impractical. Therefore, calculations can be made to translate the acceptable gas (or liquid) leak into a closed void of known volume into an allowable pressure build-up. This is an acceptable approach provided the method of calculation is documented and fits the purpose.

An example of the leak rate calculation, with compressibility, for liquid or gas is given in [Annex I](#).

### 10.4 Effects of temperature

It is necessary, especially in subsea situations, to take the effects of temperature into account in these calculations, since the wellbore, flow lines, manifolds, risers, etc., cool down quickly when remotely actuated valves are closed.

Sometimes these temperature effects can mask any interpretation of leak flow rate.

In these cases, establishing the leak rate might not be possible, and it can be necessary for valve testing to rely on indirect indications such as the temperature itself or interpretation of control line response characteristics.

### 10.5 Direction of flow

As a general rule, a component should be tested in the direction of flow. If this is impossible or impractical, a test of the component in the counter-flow direction should be performed, where possible. The test can be of limited value in establishing the component's ability to seal in the direction of flow. Any component tested in the counter flow direction should have this documented.

### 10.6 Integrity of barriers to conduct well maintenance and repair

In the case of an in-line valve that requires maintenance or repair, there can be pressure sources both upstream and downstream to consider when isolating the valve in preparation for breaking containment. A double block-and-bleed or two barrier principle should be applied for upstream or downstream isolation.

### 10.7 ESD/related safety systems

Performance requirements for emergency shutdown system are in accordance to ISO 10418 or US reference API RP 14C.

In addition to the requirements of API RP 14H, the Well Operator should define the cause and effects matrix for the emergency shutdown system; see [Table 2](#).

Shutdown systems **shall** be related to the overall well hook-up and the consequence of failure, i.e. the production pipeline rating or the flare knock out vessel capacity, and **shall** determine the closure time and function of any ESD system.

This implies that electric submersible pumps, beam pumps, progressive cavity pumps and gas lift systems, when capable of exceeding flow line pressure when closed-in, should have a shutdown system that responds adequately to prevent loss of containment and **shall** be maintained accordingly.

**Table 2 — Example of a cause and effects matrix**

Example of a Cause and effects Matrix									
	Surface safety valve flow wing	Upper master gate valve	Subsea TIV ( tree Isolation valve )	Subsurface safety valve	Gaslift shut down valve	Steam injection Shutdown valve	Beam pump / ESP shutdown	Gas blanketing shut down valve	
Emergency shutdown level 1	1		1			1	1		Closure sequence examples
Emergency shutdown level 2	1	2			1			1	
Emergency shutdown level 3	1	2		3					
Example closure times	30 s	30 s	60 s	30 s after UMG	30 s	30 s		30 s	

### 10.8 Well component operating procedure

The Well Operator shall establish the effective start up and shut down sequencing of the ESD's, SCSSSV's, SSV chokes and additional manual valves as part the well operating procedure.

EXAMPLE A typical open up sequence is as follows.

- a) Well master valve and SCSSSV is opened.
- b) Upper master ESD is opened
- c) Manual flowing valve with SSV is opened
- d) Well can be brought on line up using the flow wing valve choke in accordance with the maximum drawdown defined for the well operating envelop.

## 11 Well operating and component limits

### 11.1 Well operating limits

11.1.1 The Well Operator **shall** identify the operating parameters for each well and clearly specify the operating limits for each parameter. The well should not be operated outside of the operating limits.

The well operating limits **should** be based on the specifications of the components that make up the well with their design factors and performance standards applied.

Any changes in well configuration, condition, life cycle phase or status requires the well operating limits to be checked and potentially updated.

The Well Operator **shall** clearly define

- responsibilities for establishing, maintaining, reviewing and approving the well operating limits;
- how each of the well operating limits parameters should be monitored and recorded during periods when the well is operational, shut-in or suspended;
- life-cycle of the well;
- requirements for any threshold settings for the well operating limits;
- actions that should be taken in the event a well operating parameter is approaching its defined threshold;
- actions, notifications and investigations required if well operating limits thresholds are exceeded;
- safety systems that are necessary for assurance of operating limits.

The well operating limits **shall** be presented in a format that is readily available and unambiguous for all personnel involved in operating the well.

**11.1.2** The well operating limits parameters can change over the life of the well and can include, but are not limited to,

- wellhead/tubing head production and injection pressure;
- production/injection flow rates;
- annulus pressures (MAASP) (see [13.7](#));
- annulus pressures, bleed-offs and top-ups;
- production/injection fluid corrosive composition (e.g. H<sub>2</sub>S, CO<sub>2</sub>, etc. limitations);
- production/injection fluid erosion (e.g. sand content and velocity limits);
- water cuts and BS&W;
- operating temperature;
- reservoir draw-down;
- artificial lift operating parameters;
- control line pressure and fluid;
- chemical injection pressure and fluid;
- actuator pressures and operating fluids;
- well kill limitations (e.g. limits on pump pressures and flow rates);
- wellhead movement (e.g. wellhead growth due to thermal expansion and wellhead subsidence);
- cyclic load limitations leading to fatigue life limits, e.g. risers, conductor casing, thermal wells;
- allowable bleed-off frequency and total volume, per annulus;
- naturally occurring radioactive material (NORM) production;
- corrosion rates;
- tubing and casing wall thickness;
- cathodic protection system.

**11.1.3** The Well Operator may also consider capturing any wellhead and Christmas tree load limitations in the well operating limits, such as limits on axial, bending, lateral and torsional well loading limits, as may be applied during well interventions.

An example of a well operating limits form can be found in [Annex J](#).

## 11.2 Well load and tubular stress analysis

**11.2.1** The Well Operator should identify critical casing and tubing load cases that may be applied during the operating life cycle of the well. Such load cases should include, but not be limited to,

- production;
- Injection;

- well kill;
- well intervention;
- well stimulation.

**11.2.2** During the well life cycle, it can be necessary to re-evaluate the load cases and the well operating limits. Such a re-evaluation may be triggered by the following events:

- well anomaly;
- well integrity issues;
- change in well function;
- change in well service (well status);
- developments in technology relating to calculation techniques or processes;
- well review;
- extension of the end of well life.

### 11.3 Further well-use review

The Well Operator **shall** establish a review process and its frequency to review the well status, i.e. operating, closed in, suspended, and establishes its further use.

The Well Operator **shall** establish a plan that identifies restoration to production, injection, suspension or abandonment of the identified wells, which is in accordance with the WIMS to mitigate the risk of loss of containment.

### 11.4 End-of-life review

The Well Operator **shall** define the end of well life and establish a formal end-of-well-life review process. The end of well life triggers the review that assesses the well status for safe continuation. If the well assessment demonstrates that the well is unsafe for continued use, the Well Operator **shall** plan either to rectify the well condition or plan for suspension or abandonment. The period by which a well's life can be extended is determined on a case-by-case basis.

### 11.5 Management of change to the operating limits

Any planned deviation from the approved operating limits should be subject to a management-of-change procedure (see [Clause 17](#)). Any unplanned event that causes the well to be operated outside the approved operating limit should be the subject of investigation and addressed in the Reporting (see [Clause 18](#)) and Audit (see [Clause 20](#)) procedures.

## 12 Well monitoring and surveillance

### 12.1 General

The Well Operator **shall** define the monitoring and surveillance requirements to ensure that wells are operated within their envelope. The Well Operator **shall** determine the frequency of monitoring and surveillance, based on the risk and consequence of breaching the barrier envelopes and the ability to respond.

Monitoring is the observation of the operating parameters of a well, via instrumentation, on predefined frequency to ensure that they remain within its operating limits, e.g. pressures, temperatures, flow rates.

Surveillance is the recording of physical characteristics of the well, e.g. tubing wall thickness measurements, visual inspections, sampling.

The monitoring and surveillance parameters are detailed in [Clause 11](#) well operating limits.

## 12.2 Monitoring and surveillance frequency

The Well Operator **shall** define and document the schedule, frequency and type of monitoring and surveillance required.

A risk-based approach can be used to define the monitoring and surveillance frequencies (see [Figure 3](#)).

The frequency may be adjusted either if it is found that the monitoring and surveillance activities are resulting in a higher- or lower-than-forecasted number of non-conformances or based on risk considerations such as reliability or mean-time-to-failure analysis. The well monitoring and surveillance program should consider, at a minimum, the following main elements:

- well status: injecting, producing, shut-in, suspended, abandoned;
- operating limits;
- corrosion;
- erosion;
- structural well support integrity;
- wellhead elevation;
- reservoir subsidence.

## 12.3 Shut-in wells

A shut-in well is a well with one or more valve(s) closed in the direction of flow.

A well with a back-pressure valve or tubing-hanger plug installed is considered to be a shut-in well, not a suspended well.

A shut-in well **shall** be monitored according to a risk-based schedule defined by the Well Operator, with due consideration of the risk profile brought about by the change in flow and non-flow wetted components (see 3.19).

The status and monitoring requirements of a shut-in well are not determined by whether or not it is hooked-up to production and ESD facilities.

## 12.4 Suspended wells

A suspended well is one that has been isolated from the producing reservoir via a deep-set down-hole isolation device (mechanical or cement plug); components above the isolation device are no longer considered flow wetted.

NOTE A SSSV is not considered a down-hole isolation device in this case.

A suspended well **shall** be monitored according to a risk based schedule defined by the Well Operator, with due consideration of the risk profile brought about by the change in flow- and non-flow-wetted components (see 3.19).

The status and monitoring requirements of a suspended well are not determined by whether or not it is connected to production and ESD facilities.

A well **shall not** remain a suspended well indefinitely. The Well Operator should establish a periodic review process for suspended wells that documents and details the intended plan for the well, which may include its permanent abandonment.

## 12.5 Visual inspection

Visual inspection is undertaken to assess the general condition of the surface or mud-line equipment, as well as associated protection around the well.

The items included in a visual inspection are, but not limited to,

- physical damage to well equipment, barriers, crash frames or trawl deflectors;
- all connections to the well are secure and intact, e.g. instrumentation and control lines;
- well cellars are clean and free of debris or fluid, including surface water, build-up;
- general condition of the well head and Christmas tree: mechanical damage, corrosion, erosion, wear;
- observation of leaks or bubbles emanating from the Christmas tree or well head, especially from annuli and other cavities that are not tested or monitored by other means.

If any leaks or bubbles are observed, an estimate of the flow rate should be made and a plan for containment and repair implemented.

## 12.6 Well logging

**12.6.1** Well logging techniques are often the only means of evaluating the condition of some well barrier elements such as cement, casing, tubing, etc. These logging and surveillance techniques may be part of a pre-planned surveillance programme, or may be initiated in response to an event or an observed anomaly.

Well logging may be approached in different ways:

- individual well basis, i.e. assessing the condition of the well;
- cluster or field-wide basis, whereby sample wells are assessed and the results cascaded across the cluster/field.

**12.6.2** Well logging may include the following types of measurement:

- corrosion calliper;
- acoustic;
- sonic and ultra-sonic;
- magnetic eddy current;
- magnetic flux leakage;
- temperature;
- pressure;
- production logging: flow and phase;
- distributed temperature and sonic;
- water-flow logging;
- video and camera;

- tracer survey.

## 12.7 Corrosion monitoring

**12.7.1** Corrosion of structural or pressure-containing components of the well can lead to a loss of well integrity.

A well is generally exposed to two distinct corrosion processes:

- internal corrosion that originates from reservoir effluents or imposed effluents, injection effluents, drilling mud, or completion brines;
- external corrosion that originates from air contact with water, such as
  - surface water,
  - static subsurface water or aquifers.

Both internal and external corrosion lead to structural integrity problems and a potential loss of containment if not mitigated in a timely fashion. The Well Operator should define the monitoring program and frequency based on the assessment of the corrosion risk to the structural and well barrier elements, which may be adjusted depending on the results of inspections performed.

**12.7.2** Corrosion management programs may include

- selection of materials resistant to corrosion;
- estimates for corrosion rates for barrier elements over the design life of the well; such estimated corrosion rates should be based on documented field experience, or modelled using recognized industry practice;
- indirect measurements, such as sampling annulus or well fluid for corrosive chemicals (e.g. H<sub>2</sub>S, acid) and by-products of corrosive reactions;
- monitor chemical injection into the fluid flow path;
- monitoring of chemical inhibition of annulus fluids;
- isolation of annuli from oxygen sources;
- cathodic protection.
- periodic examination of protective coatings (e.g. where accessible, to conductors, wellhead, Christmas trees, etc.) and structural members, such as conductors and surface casing.

## 12.8 Cathodic protection monitoring

When wells are at risk due to corrosion from external environmental influences, such as sea water, aquifers or swamps, it is necessary for the Well Operator to assess the risk and define the means of protection against failure. One such system that can be applied to protect bare steel components, such as casing and conductors, is a cathodic protection system.

It is necessary for the Well Operator to have an assurance system in place to verify that the cathodic protection systems (where applicable) are operating as per the design intent.

Further information on these systems can be obtained from NACE SPO169-2007 and NACE AS 2823.4-1994.

## 12.9 Erosion monitoring

The erosion of components in the flow path within the wellbore, wellhead and Christmas tree can lead to loss of well integrity.

Particular attention should be given to sections in the flow path where velocity and turbulence can increase, such as can occur at changes in cross-sectional area in the completion string, and in cavities within the Christmas tree assembly.

Flow and velocity limits should be based on the established wellbore fluid composition and solids content and should be set in accordance with ISO 13703, NORSOK P-001, DNV RP 0501 or API RP 14E.

Where there is any significant change in wellbore fluid composition or solid content, the erosion risk and velocity limits should be reassessed.

For wells that are operating close to the velocity limits, an erosion-monitoring program should be established, and form part of the well inspection and maintenance program.

Flow and velocity limits should be stated in the well operating limits (see [Clause 11](#)).

For each barrier element, the Well Operator should establish and document acceptable limits of erosion. Such limits should be based on the preservation of well integrity for the defined well life-cycle load cases.

### 12.10 Structural integrity monitoring

The conductor, surface casing (and supporting formations) and wellhead assembly typically provide structural support for the well. Failure of these structural components can compromise well integrity and escalate to a loss of containment.

Potential failure modes for structural components can include, but are not limited to,

- metal corrosion;
- metal fatigue due to cyclic loads;
- degradation of soil strength due to cyclic, climatic and/or thermal loads;
- sideways loading due to squeezing formations or earthquake.

Subsea and offshore structural components can be subject to additional loads arising from temporary equipment attached to the well, such as drilling or intervention risers.

For each well, the Well Operator should assess the risk of failure of such structural components. The assessment of the risk should be included in a failure modes and effects analysis (FMEA).

The Well Operator should establish suitable systems to model or measure degradation in the structural members of the well. In some instances, it is not possible to directly measure the affects of cumulative fatigue and, therefore, a tracking and recording system is required to assess the predicted consumed life of the components (see ISO 13628-1 for further information).

#### 12.10.1 Well elevation monitoring

Unexpected changes in well elevations can be an indication of the degradation of structural support of the well and can escalate to impacting on a well's integrity.

Elevation monitoring and recording should form part of the well inspection program (see [12.5](#)). The top of the conductor and the wellhead, relative to an established datum should be recorded. Data should also include the wellhead temperature at the time the elevation measurement was taken. Depending on the well configuration, it can be normal for the well to “grow” when transitioning from a cold shut-in to a hot production condition.

When monitoring for subsidence or elevation of the well and its surroundings, the datum reference should be periodically verified and recorded.

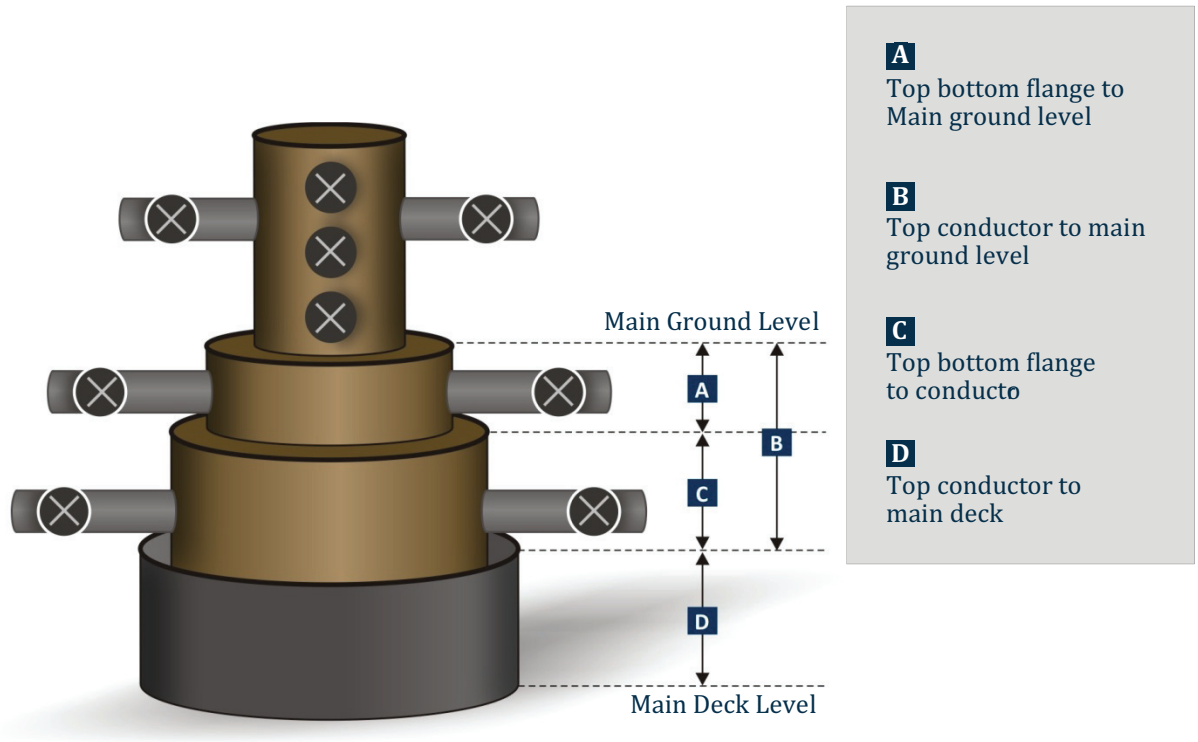


Figure 5 — Example of subsidence measurement

### 12.10.2 Reservoir subsidence

In some mature fields, depletion of reservoir pressure, or a reservoir pressure increase, has led to compaction or elevation of the reservoir rock and / or subsidence of the overburden formation(s). Resultant changes in the tectonic stress regime can also activate faults. This has the potential to impose significant loads on casing strings, leading to casing failure. Also, the subsidence can undermine a platform or well pad.

The Well Operator should make an assessment of the potential for compaction and subsidence. Where it is assessed to be a risk, suitable monitoring programs should be established.

Such programs may include

- surface measurements;
- down-hole wellbore measurements;
- down-hole mechanical failures;
- loss / reduction of production;
- seismic survey studies.

## 13 Annular pressure management

### 13.1 General

There are three types of annular pressure that can occur during the well's life cycle generally referred to as follows:

- The Well Operator-imposed annulus pressure is pressure that is deliberately applied to an annulus as part of the well operating requirements. Typically, this can be gas lift gas in the A-annulus or applied pressure in A annulus in order to protect against collapse risk from trapped annular pressure in B annulus on subsea wells.
- Thermally induced annulus pressure is pressure in a trapped annulus volume that is caused by thermal changes occurring within the well.
- Sustained annulus pressure (SAP) is a pressure which occurs in an annulus that rebuilds after having been bled-off and cannot be attributed to the Well Operator imposed or thermally induced pressure. SAP is of particular concern as it can be indicative of a failure of one or more barrier elements, which enables communication between a pressure source within the well and an annulus. This, by definition, means that there is a loss of integrity in the well that can ultimately lead to an uncontrolled release of fluids, which in turn can lead to unacceptable safety and environmental consequences..

### 13.2 Management

The Well Operator **shall** manage the annuli pressures such that well integrity is maintained throughout the complete well life cycle.

At a minimum, it is necessary to consider the following when managing annulus pressure based upon a risk assessment:

- pressure sources;
- monitoring, including trends;
- annulus contents, fluid type and volume;
- operating limits, including pressure limits, allowable rates of pressure change;
- failure modes;
- pressure safety and relief systems.

### 13.3 Sources of annular pressure

**13.3.1** The source of annulus pressure can be due to several factors:

- temperature changes that occur within the well that create thermally induced pressure (e.g. well start-up and shut-in, due to neighbouring wells, increased water production, etc.);
- deliberate actions taken by the Well Operator to increase the pressure within an annulus;
- communication with a pressure source, for example
  - reservoir,
  - lift gas,
  - water injection,

- shallow over-pressured zones (as a result of hydrocarbon migration or changes in the formation overburden);

**13.3.2** Communication with a pressure source may be due to one, or more, of the following failure modes:

- casing, liner, tubing degradation as a result of corrosion/erosion/fatigue/stress overload;
- hanger seal failure;
- annulus crossover valve leak in a subsea Christmas tree;
- loss of cement integrity;
- loss of formation integrity, e.g. depletion collapse, deconsolidation, excessive injection pressure, compaction;
- loss of tubing, packer and/or seal integrity;
- leaking control/chemical injection line;
- valves in wrong position

NOTE API RP 90 contains methods that can aid in the determination of the nature of the observed annulus pressure.

### 13.4 Annulus pressure monitoring and testing

**13.4.1** Any change of annulus pressure, increase or decrease, can be indicative of an integrity issue. The regular monitoring of the well tubing and annuli during well operations enables early detection of threats to, or a potentially compromised, well barrier envelope.

The Well Operator **shall** define a program to monitor the annuli pressure.

To effectively monitor annulus pressures, the following should be recorded:

- fluid types and volumes added to, or removed from, the annulus;
- fluid types, and their characteristics, in the annulus (including fluid density);
- monitoring and trending of pressures;
- calibration and function checks of the monitoring equipment;
- operational changes.

**13.4.2** Where applicable, in the annuli, it can be useful to maintain a small positive pressure on sections equipped with pressure monitoring such that leaks in the annuli can be detected.

The Well Operator **shall** define the need for annulus pressure testing or integrity verification, by other methods, when

- changing the well functionality, i.e. from producer to injector, etc.;
- there is a risk of external casing corrosion as a result of aquifer penetration;
- there is a lack of evidence from positive pressure monitoring.

### 13.5 Frequency of monitoring tubing and annulus casing pressures

The Well Operator **shall** determine the frequency of monitoring and surveillance.

Consideration should be given to the following items when establishing the monitoring frequency:

- a) expected temperature changes and effects, especially during start-up and shut-in;
- b) risk of exceeding MAASP or design load limits,
- c) risk of sustained annulus pressure;
- d) response time for adjusting annulus pressure;
- e) sufficient data for trending and detection of anomalous pressures;
- f) deterioration from corrosive fluids (e.g. H<sub>2</sub>S and chlorides);
- g) operating characteristics of control/injection lines (e.g. chemical injection lines, size, operating pressure etc.);
- h) annuli used for injection;
- i) changing the well function, i.e. from producer to injector, etc.;
- j) there is a risk of external casing corrosion as a result of aquifer penetration.

### 13.6 Identification of an annulus pressure source

A bleed-down/build-up test performed on the annulus is one method to confirm the nature of the pressure source. The influx of fluids due to sustained annular pressure can carry a risk of contaminating the annulus contents and this should be evaluated when performing bleed-down testing operations.

The Well Operator should establish a procedure for conducting the pressure bleed-down/build-up tests. An example of a methodology for performing such tests can be found in API RP 90.

The process should include recording of surface pressures and the volumes and densities of liquids and gases bled-off or topped up, in the annulus. These values are required to investigate the sustained annular pressure with a view to mitigating the subsurface risk of a loss of containment.

Additional information to establish the source of an anomalous pressure can sometime be obtained by manipulating a neighbouring annulus pressure.

After an anomalous annulus pressure has been identified, records and well history should be reviewed to determine the potential cause(s) or source(s) of the pressure.

The Well Operator **shall** assess the risk associated with a sustained annulus pressure. Such risks are related to

- flow capability of any annuli with respect to a loss of containment;
- annular gas mass storage effect (i.e. volume of gas between the annulus's liquid level and surface);
- introduction of corrosive fluids into an annulus not designed to resist such fluids;
- maximum potential pressure that can occur should the compromised barrier degrade further.

### 13.7 Maximum allowable annular surface pressure

#### 13.7.1 General

The maximum allowable annulus surface pressure (MAASP) is the greatest pressure that an annulus is permitted to contain, as measured at the wellhead, without compromising the integrity of any barrier element of that annulus. This includes any exposed open-hole formations.

The MAASP **shall** be determined for each annulus of the well. The MAASP calculation **shall** be documented together with the applied design factors.

MAASP **shall** be recalculated if

- there are any changes in well-barrier-elements acceptance criteria;
- there are any changes in the service type of the well;
- there are annulus fluid density changes;
- tubing and/or casing wall thickness loss has occurred;
- there are changes in reservoir pressures outside the original load case calculation.

The differential pressures across tubing, casing, packers and other well equipment **shall not** exceed their respective design load limits.

The Well Operator should make MAASP values available on the well barrier record.

### 13.7.2 Calculation of MAASP

The following information is necessary to calculate the MAASP:

- maximum pressure to which the annulus has been tested;
- detail of the mechanical performance specifications, or as-manufactured performance, of each component that forms the annulus;
- detail of the as-constructed well;
- detail of all fluids (density, volume, stability) in the annulus and in adjacent annuli or tubing;
- detail of casing cementation, cement tensile and compressive strength performance;
- detail of formation strength, permeability and formation fluids;
- detail of aquifers intersected by the well;
- adjustments for wear, erosion and corrosion, which should be considered when determining the appropriate MAASP to apply;
- when pressure relief devices (e.g. rupture disc) are installed in a casing, ensure that MAASP calculations include all load cases for both annuli with the relief device open and closed;
- detail of SCSSV control line actuation pressures, especially for deep water wells

Examples of the MAASP calculations are found in [Annex K](#).

### 13.7.3 Setting operating limits based on MAASP

The Well Operator should determine an operating range for each annulus that lies between defined upper and lower thresholds.

The upper threshold is set below the MAASP value to enable sufficient time for instigating corrective actions to maintain the pressure below the MAASP.

The upper threshold should not be so high that the pressure in the annulus could exceed the MAASP due to heating after shut in. This is particular relevant for an injector with cold injection medium, where any bleed off activities will not be prioritized in an emergency situation (e.g. ESD).

The lower threshold may be considered for the following reasons:

- observation pressure for the annulus;
- providing hydraulic support to well barrier elements;
- avoiding casing collapse of the next annulus (e.g. for next annulus or voids if it is not possible to bleed-off);
- avoiding hydrate formation;
- accounting for response time;
- potential small leaks;
- variability of fluid properties;
- temperature fluctuations;
- avoiding vapour phase generation (corrosion acceleration);
- preventing air ingress.

For subsea wells, it is recommended that the lower threshold be set above the hydrostatic pressure of the sea water column at the wellhead.

Operating limits are illustrated in [Figure 6](#).

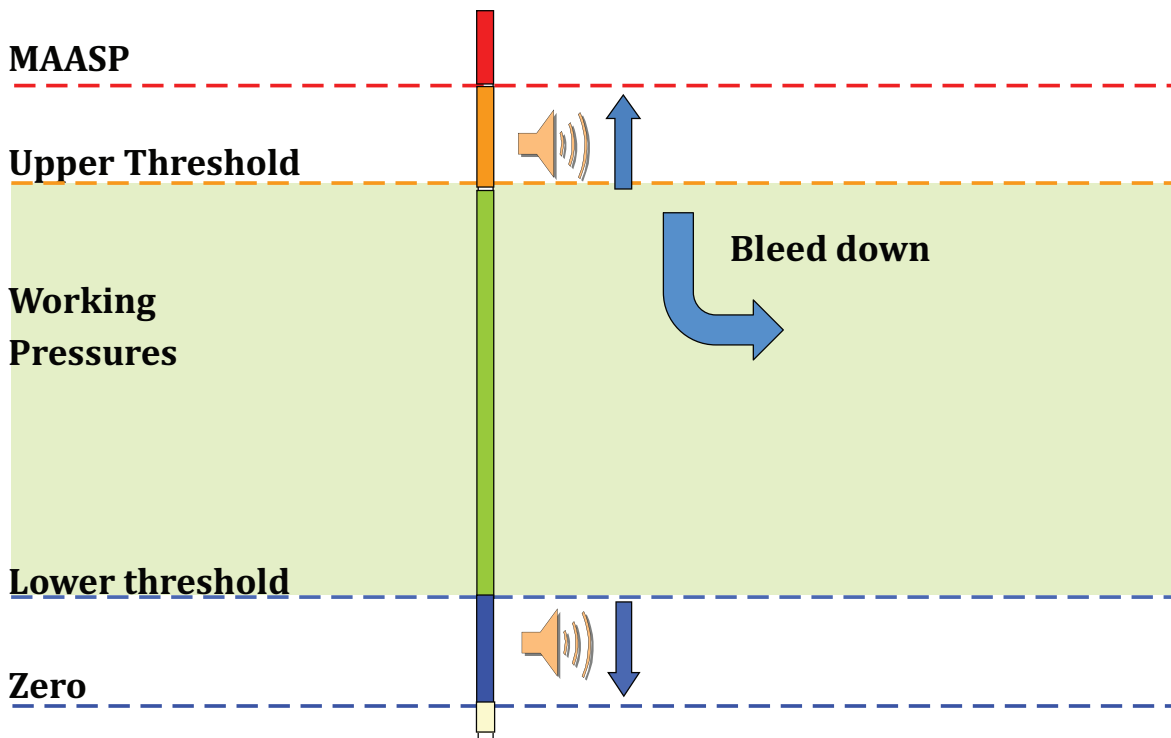


Figure 6 — Illustration of thresholds and MAASP

The operating range is applicable only to accessible annuli that allow for pressure management, such as bleed-down/build-up. Trapped annuli, without monitoring, should have been considered in the design of the well.

For active annuli, i.e. annuli that are being used for injection or gas-lift, the principles of inflow testing and monitoring of adjacent annuli/conduits should be followed.

It is recommended not to operate an annulus at a pressure that is greater than the MAASP of the adjacent annulus. If a leak occurs between the adjacent annuli, this prevents an excursion above the MAASP in the newly exposed annulus.

### 13.8 Maintaining annulus pressure within the thresholds

When the annulus pressure reaches the upper threshold value, it should be bled off to a pressure within the operating range. The annulus should be topped up when the lower threshold is reached.

The type and total volume of the fluid recovered, or added, and the time to bleed down should be documented for each bleed-down or top-up.

The frequency of bleed-downs and the total volume of fluids recovered from the bleed-downs should be monitored and recorded. These should be compared to limits established by the Well Operator in the operating limits and, when exceeded, an investigation should be undertaken.

The Well Operator shall define upper thresholds these shall not exceed 80 % of MAASP of annulus it's applied on or exceed 100 % of the MAASP of the adjacent outer annulus. Deviation from this standard should be risk assessed, mitigated and recorded through MOC with formal technical authority approval

### 13.9 Review and change of MAASP and thresholds

**13.9.1** The Well Operator **shall** define the process of annulus review (investigation) when the operating conditions indicate that the pressure is sustained or a leak in a well barrier envelope has occurred.

When such a review is required, it **shall** be defined and may be based on established criteria for

- frequency of annulus pressure blow-down or top-ups;
- abnormal pressure trends (indicating leaks to/from an annulus);
- volume of annulus blow-down or top-ups;
- type of fluid used or recovered (oil/gas/mud);
- pressure excursions above MAASP and/or upper threshold.

**13.9.2** The review **shall** focus around the following elements:

- source of the sustained annulus pressure based on sample and finger-print results compared to original mud logging data;
- source fluid composition and pore pressure;
- flow path from the source to the annulus (or visa versa) under review;
- leak rate, potential volumes and density changes in annulus;
- condition of the well (remaining life);
- content of the annulus and liquid levels;
- casing shoe strength changes.

In the event of gas being the original source of annulus pressure and the Well Operator has confirmed source of origin by finger print against original mud-logger data and assessed the risk of loss of containment (subsurface) based on shoe strength and original source pore pressure, the Well Operator may consider recalculating the MAASP taking into account the impact of the average fluid gradient estimated in the fluid column; see example in [Annex L](#) (example of change in MAASP calculation)

## 14 Well handover

### 14.1 General

**14.1.1** Well handover is the process that formalizes the transfer of a well and/or well operating responsibility and is endorsed by the use of related well handover documentation.

The Well Operator **shall** verify the well operating limits within the well handover process (see [Clause 11](#))

The process **shall** define, as a minimum, the following phases at which well handover typically occurs:

- well construction to production operations;
- production operations to maintenance, intervention or servicing, and back to production operations;
- production operations to abandonment.

**14.1.2** The Well Operator **shall** include the following in the well handover documentation in the initial handover in the construction to operation phases:

- schematic of the Christmas tree and wellhead providing, at a minimum, a description of the valves, their operating and test criteria (performance standards), test records and their status (open or closed);
- SSSV status, performance standard and test records;
- status of ESD and actuator systems
- well start-up procedures detailing production/injection rates, as well as associated pressures and temperatures;
- details of any well barriers elements left in the well (crown plugs, check valves or similar) or devices that ordinarily it would be required to remove to allow well production and/or monitoring;
- detailed description and diagram of the well barrier envelopes, clearly indicating both primary and secondary well barrier envelopes;
- detailed wellbore schematic and test records (depicting all casing strings complete with sizes, metallurgy, thread types and centralizers as well as fluid weights, cement placement, reservoirs and perforating details);
- detailed completion tally as installed (listing all component ODs, IDs, lengths, metallurgy, threads, depths);
- wellhead and Christmas tree stack-up diagram (general assembly drawing with dimensions) with a bill of materials;
- wellbore trajectory with the wellhead surface geographical coordinates;
- pressures, volumes and types of fluids left in the annuli, wellbore and tubing and Christmas tree;
- well operating limits;
- subsea control system status and test records (if applicable).

Handovers during the well lifecycle should include only those items that are appropriate and capture any changes in the well's configuration or operating limits.

The Well Operator **shall** nominate competent personnel who are responsible for preparing, verifying and accepting the well handover documentation. These persons **shall** sign and date the documentation accordingly.

Well handover documentation and requirements are specified in [Annex M](#).

## 15 Well maintenance

### 15.1 General

Maintenance activities are the means by which the continued availability, reliability and condition of the well barrier envelopes, well barrier elements, valves, actuators and other control systems are periodically tested, functioned, serviced and repaired.

The Well Operator **shall** identify all respective fitted components in a planned maintenance program. These would typically include, but are not limited to, the following components:

- wellhead, tubing hanger and Christmas tree, including all valves, bonnets, flanges, (tie-down) bolts and clamps, grease nipples, test ports, control line exits;
- monitoring systems, including gauges, transducers, sand detectors, corrosion probes etc.);
- annulus pressures and fluid levels;
- down-hole valves (SCSSV, SSCSV, ASV, gas-lift valves);
- ESD systems (detectors, ESD panels, fusible plugs);
- chemical injection systems.

Maintenance is conducted to inspect, test and repair equipment to ensure that it remains within its original operating specifications. A planned maintenance program sets out which maintenance activities are performed at a predetermined frequency.

There are two levels of maintenance, preventative and corrective.

- Preventive maintenance is carried at a predefined frequency based on the working conditions, the well type and the environment in which it is operating, i.e. offshore, onshore, nature reserve or as directed by a regulator.
- Corrective maintenance is typically triggered by a preventive maintenance task that identifies a failure or by an ad hoc requirement that is identified by a failure during monitoring of a well.

The number of corrective maintenance tasks within a given period is a qualitative indication of the quality of the preventive tasks or of the monitoring frequency. The ratio of corrective maintenance task to preventative maintenance tasks can be measured against established acceptance criteria, for example as given in Formula (1):

$$\frac{N_{CM}}{N_{PM}} \leq 0,3 \quad (1)$$

where

$N_{CM}$  is the number of corrective maintenance tasks;

$N_{PM}$  is the number of preventive maintenance tasks.

**Table 3 — Example of maintenance and monitoring matrix**

Example Well Integrity Maintenance and Monitoring Matrix									
Assurance task / well type		High pressure well offshore	Subsea wells free flowing	High pressure well onshore	Subsea well hydrostatic	Medium pressure well onshore	Low pressure well offshore	Hydrostatic well	Observation well
Maintenance	Example of time based preventive maintenance frequency in months								
	Flow wetted components maintenance and inspection frequency	6	6	12	12	12	12	24	48
	Non flow wetted components maintenance and inspection frequency	12	12	24	24	24	24	48	96
Monitoring	Example of time based preventive maintenance frequency in days								
	Monitoring frequency active wells	1	1	1	7	7	7	14	30
	Monitoring frequency annulus pressures	1	1	7	7	7	7	14	60
	Monitoring frequency inactive wells	7	7	14	30	30	30	60	90

The Well Operator **shall** have preventative and corrective maintenance management system for performing well maintenance work, including acceptance criteria, and **shall** keep auditable records of maintenance activities.

When defining schedules and test frequencies the Well Operator should take into account the following, as a minimum:

- original equipment manufacturer specifications;
- risk to environment and personnel exposure;
- applicable industry recognized standards, practices and guidelines;
- Well Operator relevant policies and procedures.

The Well Operator **shall** have a documented program for investigating leaks or faults, and a defined time to implement corrective action(s) based upon the risk. Compliance with this program **shall** be monitored.

### 15.2 Replacement parts

Well equipment that is part of a barrier element **shall** be maintained using parts that retain the current operating limits. Replacement parts should be from the original equipment manufacturer (OEM), or an OEM-approved manufacturer. Deviation from this practise should be clearly documented and justified.

### 15.3 Frequency of maintenance

The Well Operator **shall** define and document the schedules and frequencies for maintenance activities. A risk-based approach can be used to define the frequency and an assessment matrix as shown in [Figure 3](#) can be used in the process that can be mapped as per example in [Table 3](#).

The frequency may be adjusted if it is found that the ratio preventive/corrective maintenance tasks is very high or very low once sufficient historical data have been obtained that establish clearly observable trends.

### 15.4 Component testing methods

The types of tests that may be performed as part of the maintenance program and in accordance with the performance standards as defined by the Well Operator are outlined in [Annex E](#) performance standard for well safety critical elements.

### 15.4.1 Verification testing

A verification test is a check whether a component meets its acceptance criteria.

Verification testing includes, but is not limited to,

- function testing:
  - valve functioning,
  - valve closing times,
  - actuator travel distances,
  - valve handle turns,
  - hydraulic signature (analysis of control-line response);
- leak testing:
  - inflow testing,
  - pressure testing,
  - annulus testing,
  - bleed-downs.

### 15.4.2 Function testing

Function testing may be performed on, but not limited to,

- valves;
- safety shutdown systems;
- alarms;
- gauges.

Function testing is a check as to whether or not a component or system is operating. For example, the function test of a valve indicates that the valve cycles (opens and closes) correctly. It does not provide information about possible leaking of the valve.

The Well Operator may consider a higher frequency of function testing in addition to the regular verification tests. In the case of DHSVs or also referred to as SSSV's, for example, regular function testing can often ensure fewer problems when verification testing is performed.

Function testing may completely replace verification testing in cases where it is neither practical nor possible to perform pressure tests or inflow tests as a part of a verification test. Function testing that confirms actuator movement and/or valve movement can be of value.

Function and performance testing of ESD/SSV valves **shall** be carried out as defined in API RP 14H. This recommended practice should also be applied to onshore wellhead and Christmas tree ESDs.

For manual valves, function testing is done by cycling the valve while counting the turns of the handle and verifying that the valve cycles smoothly.

For actuated valves, verify that the valve stem travels the full distance and measure the opening and closing times.

For some valves, where it is not possible to observe movement of the valve's stem, it is possible to verify its correct functioning by observing the hydraulic signature (the control line pressure data). Examples

of the hydraulic signature of a surface controlled subsurface safety valve (SCSSV) and a valve of a subsea Christmas tree are shown in [Annex N](#).

In the case of a successful valve inflow test, it can be assumed that the actuation system to close that valve is functioning correctly to the extent that the valve closes. However, it does not necessarily confirm that the actuation system itself is functioning in accordance with its operating parameters, such as time-to-function, sufficient accumulator capacity, operating pressure, etc.

Valves in the flow path (SSSV, master valves, wing valves) should not be function tested while the well is flowing, as this can damage internal valve components and is not an acceptable practice.

Two types of subsurface controlled subsurface safety valves are used: valves that close when the pressure drops below a certain value (ambient-type valves) and valves that close when the flow rate exceeds a certain value (velocity-type valves, also known as storm chokes). Both these types of valves can be verified only by an inflow test after closing the valve in accordance with the manufacturer's procedures. Often, this requires that the well be lined up to a low-pressure test separator or a flare to simulate uncontrolled flow to surface conditions. This is often impractical during well operations and, under these circumstances; the Well Operator should maintain such valves by establishing a frequency for replacement.

### 15.5 Leak testing

Leak testing is the application of a differential pressure to ascertain the integrity of the sealing system of the component. The application of a differential pressure may be obtained by either pressure- or inflow-testing results should be expressed in ambient pressure volumes.

The differential pressure applied and the duration of the test is determined by the Well Operator such that the change in pressure versus time is measurable for the fluids and for the volumes into which the fluids are flowing.

The following should be taken into consideration.

- The differential pressure that is required to initially energize the sealing system, particularly a floating-gate valve (for example, 1.379 MPa to 2.068 MPa [200 psi to 300 psi] is typically required).
- In situations where external pressure is not available or practical to apply, test results should be recorded as function tests only.

#### 15.5.1 Inflow testing

Inflow testing uses the tubing or casing pressure to perform leak testing. The valve that is tested is closed, the pressure downstream of the valve is reduced to create a pressure differential across the valve and the volume downstream of the valve is monitored for a pressure increase that indicates a leak through the closed valve.

#### 15.5.2 Pressure testing

Pressure testing is the application of a pressure from an external source (non-reservoir pressure) to ascertain the mechanical and sealing integrity of the component.

Fluids introduced into well, annuli and voids during testing should be assessed as to their corrosion potential, for example the introduction of sulfate-reducing bacteria (SRBs). This may involve

- using treated water (e.g. with low chloride and sulfur content);
- increasing the pH of the test media;
- adding a biocide and oxygen scavenger to the test media.

Alternatively, use of an inert gas, such as nitrogen, for pressure testing can be considered.

### 15.5.3 Gas lift check valve function testing

Periodic verification testing of gas-lifted annulus sections **shall** be performed when gas-lift valves are a well barrier element. The objective of these tests is to confirm that the non-return valves of the gas-lift valves are functioning and to confirm tubing and packer integrity. An example of how this can be done is presented in [Annex H](#).

## 16 Well integrity failure management

### 16.1 General

The Well Operator **shall** establish a process that describes the management of risks associated with failure(s) of a well barrier envelope or well barrier element(s) against their performance standards, as defined by the Well Operator, legislation or industry standard.

The process **shall** describe the course of action to correct the failure, based on the number of barrier or barrier elements that remain functional that is, the level of redundancy of barriers or barrier elements of the well.

### 16.2 Integrity failure ranking and prioritization

A well integrity failure **shall** be risk-assessed against the criticality of the failed barrier element, taking into account the redundancies in place.

The priority-to-repair (response time) **shall** be set in accordance with the risk exposure.

The Well Operator **shall** have a risk-based repair model and structure in place that provides guidance for adequate resources, such as spares, tools, contracts, etc., in order to meet the response time to affect repairs as defined in the model.

The well integrity response model **shall** include, but is not be limited to,

- well type identification based on risk;
- single barrier element failures;
- multiple barrier element failures;
- time-based course of action.

(See also [8.4](#)).

### 16.3 Well failure model

A well failure model approach may be adopted to streamline the risk assessment process, the plan of action and the response time to repair when failures occur. A well failure model is constructed as a matrix that identifies the most common modes of well failure seen by the Well Operator. Each mode of failure has an associated action plan and associated response period. By having agreed action plans and response times, the Well Operator is able to manage equipment, spare parts, resources and contracts to meet the response times specified in the well failure model.

A well model is constructed in a step by step approach.

- a) Identify typical modes of failure, both surface failures, and sub-surface failures. These failure modes can be documented in a list format or illustrated on a diagram.
- b) Once the failure list is constructed, an action plan, including resources required and responsibilities for each identified failure is agreed. Due consideration for escalation of response time to multiple failures should be captured, since the combined result of two simultaneous failures can often be more severe than had the two failures occurred separately.

- c) A risk-assessed time to respond to the failure is assigned to each action plan. Here it is captured whether it is allowed to operate, close in or suspend a well during these periods.
- d) It is often useful to rank or categorize failures for the purpose of prioritization and reporting. This may be a “traffic light” approach (red, amber, green) or a ranking system (1 to 10 for example).

By adopting a well failure model, the Well Operator has predefined the level of risk, the actions, response times and resources required for common modes of well failure.

Any well failures that occur that are not covered by the well failure model are risk-assessed in the conventional manner.

**Table 4 — Example of well failure model matrix**

<b>Example Well Integrity Well Failure model concept / Corrective Response</b>									
Failed component (s) / well type		High pressure well offshore	Subsea wells free flowing	High pressure well onshore	Subsea well hydrostatic	Medium pressure well onshore	Low pressure well offshore	Hydrostatic well	Observation well
<b>Time allowed to conduct corrective actions / repair</b>	Example Flow wetted component failures single response frequency in months								
	Xmas tree master valve	1	3	3	3	3	3	6	12
	Flowing valve	3	3	6	6	6	6	12	24
	subsurface safety valve	1	3	3	3	3	3	NA	NA
	Production packer	6	6	12	12	12	12	NA	NA
	Gaslift valve	3	3	6	6	6	6	12	24
	Tubing	6	6	12	12	12	12	24	48
	Example Flow wetted component failures multi response frequency in months								
	X mas tree master valve + subsurface safety valve	0	0	1	2	2	3	NA	NA
	X mas tree Flow wing valve + Master valve	1	0	2	3	3	4	6	12
	Example Non flow wetted component failures multi response frequency in months								
	Annulus side out let valve	3	3	6	6	6	9	12	12
	Annulus to Annulus leak	6	6	6	6	12	12	12	12
	Sustained casing pressure investigate	1	1	1	1	1	1	2	2
	Example Non flow wetted component failures multi response frequency in months								
	Sustained casing pressuer + annulus valve	1	1	1	1	2	2	3	3
	Annulus leak + sustained annular pressure	1	1	1	1	2	2	6	6
	Combined Flow wetted and non flow wetted component failures response frequency in months								
	Production tubing + casing leak	1	1	1	1	2	4	6	6
Master valve + annulus valve	2	2	2	2	3	6	9	9	
Sustained intermediate annular pressure + tubing leak	1	1	2	2	3	3	6	6	

## 17 Management of change

### 17.1 General

The Well Operator **shall** apply a management of change (MOC) process to address and record changes to integrity assurance requirements for an individual well or to the well integrity management system.

The Well Operator **shall** apply a deviation process that assesses and manages the risk(s) that apply to temporary non-compliance to the well integrity management system.

Deviations **shall** be time bound and, if extended, the approval process may escalate in approval level within the Well Operator organization.

### 17.2 Integrity deviation process

There can be instances when the exposure to further risk or the level of system impairment on reinstatement of the original barrier arrangement is grossly out of proportion to the reduction in risk likely to be achieved by implementing the repair. In such instances, and after careful consideration and justification, a dispensation or waiver to operate the well outside the performance standard or well integrity policy may be applied for from the respective authority.

### 17.3 Deviation from the well performance standard

The Well Operator **shall** have a procedure that clearly specifies the process and approvals required for deviation from the standard. Where compliance with the standard(s) is required by local law, the process **shall** address how to engage the local regulator.

### 17.4 MOC Process

The MOC should include the following process steps.

- Identify a requirement for change.
- Identify the impact of the change and the key stake holders involved. This includes identifying what standards, procedures; work practices, process systems, drawings, etc. would be impacted by the change.
- Perform an appropriate level of risk assessment in accordance with the Well Operator risk assessment process (see [Clause 8](#)). This would include
  - identifying the change in risk level(s) via use of a risk assessment matrix or other means,
  - identify additional preventative and mitigating systems that can be applied to reduce the risk level,
  - identify the residual risk of implementing the change/deviation,
  - review the residual risk level against the Well Operator risk tolerability/ALARP acceptance criteria.
- Submit MOC proposal for review and approval in accordance with the Well Operator authority system.
- Communicate and record the approved MOC.
- Implement the approved MOC.
- At the end of the approved MOC validity period, the MOC is withdrawn, or an extension is submitted for review and approval.

NOTE If the change is permanent, its implementation ends the MOC process.

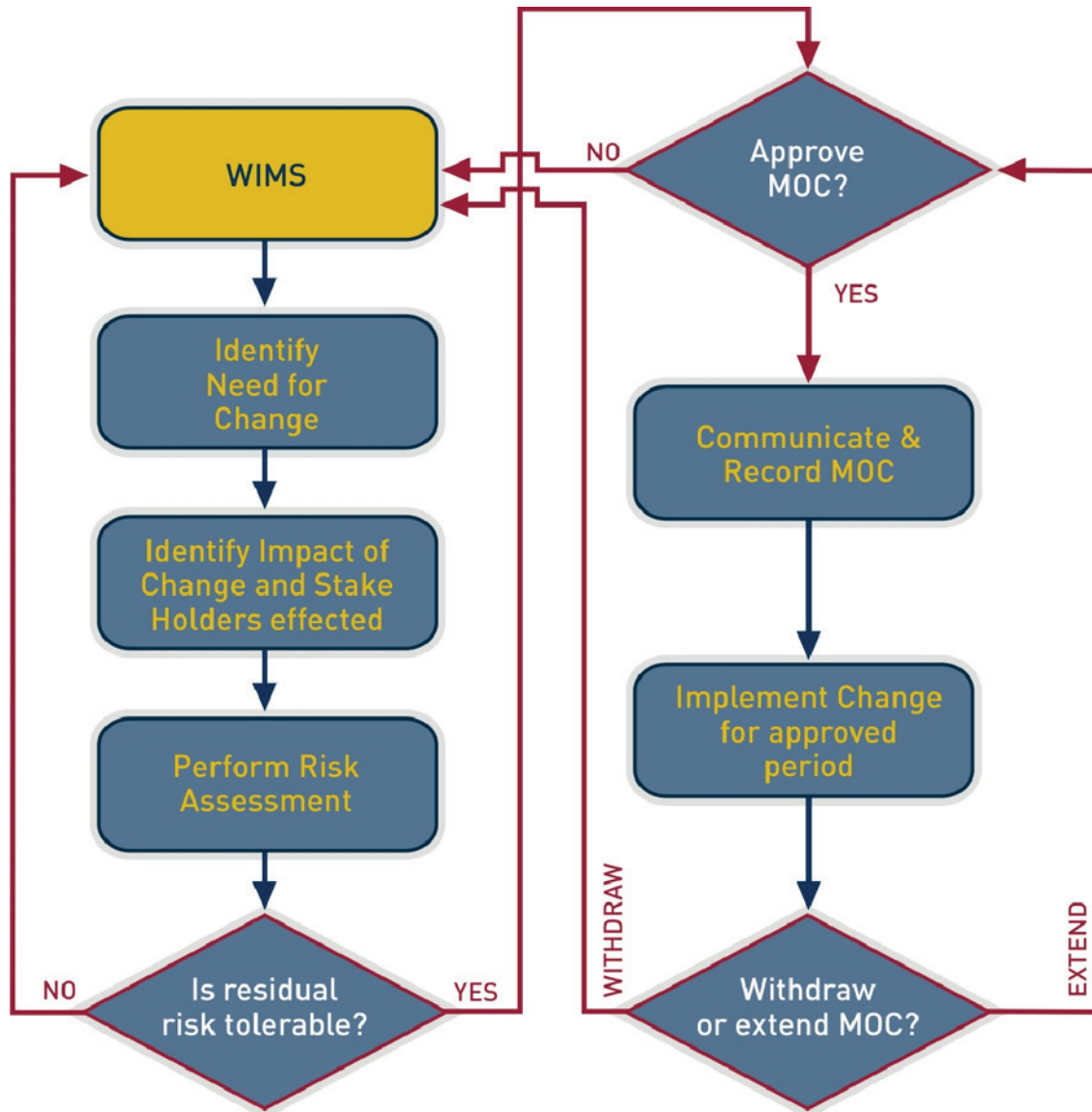


Figure 7 — Example of an MOC flow diagram

## 18 Well records and well integrity reporting

### 18.1 General

The keeping of complete records is necessary so that all authorized users of the information can quickly and accurately determine the current status of a well’s integrity and its well barrier elements. Additionally, such users can ensure, or demonstrate, that maintenance, testing, inspection, repair and replacement has been performed in accordance with the requirements of the well integrity management system.

At a minimum, the Well Operator **shall**

- maintain a repository, providing access to data and documents for all relevant users;
- develop a documented process and procedure for controlling and updating data and documents;
- establish a data/document maintenance feature to combat degradation and ensure software (where used) inter-changeability;

- define and staff functions responsible for data collection and document management;
- define those who are authorized to have access to the records;
- define how long records are retained;
- ensure that the system is in compliance with any governmental regulations.

## 18.2 Well records

The Well Operator should define the information and records about a well that it is necessary to store. These should typically include, but not necessarily be limited to,

- well barrier element specifications;
- well operating limits information;
- well status (e.g. producing, shut-in, abandoned);
- handover documentation;
- diagnostic tests performed;
- production/injection information;
- annulus pressure monitoring;
- fluid analyses;
- maintenance, repair and replacement activities (OEM traceability).

## 18.3 Reports

**18.3.1** The Well Operator **shall** define the minimum reporting requirements to effectively reflect the application of the WIMS and all its elements.

These may include

- routine reports issued on a predefined periodic basis (e.g. monthly, quarterly, or annually) reflecting the well integrity activities and issues addressed;
  - reporting on the identified KPI's (see [19.3](#));
  - event-specific well integrity incident and WIMS non-compliance reports and investigations;
  - WIMS audit reports (see [Clause 20](#));
- reporting to the government/regulator as required by local legislation.

**18.3.2** The WIMS should define the scope, recipients and acknowledgement of receipt of all such reports.

Topics covered in the reports may include the following, but is not limited to,

- previous well reviews, or ad hoc well reviews;
- changes to the original boundary conditions;
- change in the well's function;
- changes in the well fluid composition;
- change or possible degradation of well and well related hardware;

- examination of MOC notices;
- examination of well deviations issued;
- well barriers;
- well integrity issues;
- scale or corrosion issues;
- wear and tear to hardware and equipment;
- accidental damage to hardware and equipment;
- equipment obsolescence;
- loss of barrier or containment;
- environmentally related changes;
- statutory or legislative changes;
- changes in local procedures and standards;
- changes to the local operating risk model;
- advances in technology that may be implemented;
- changes to the operating limits of equipment/material, e.g. latest manufacturer's bulletins or industry standards;
- repairs to, and replacements of, well components, from valve parts to complete work over;
- relevant equipment maintenance information in order to improve equipment technical specifications, reliability data and/or preventive maintenance intervals.

## 19 Performance monitoring of well integrity management systems

### 19.1 Performance monitoring and continuous improvement

The techniques and processes used to support the key elements of the well integrity management system described in [5.2](#) and any other elements defined by the Well Operator should be routinely monitored to ensure that they are effective.

There are several methods that can be employed to perform such performance monitoring, including

- performance review (see [19.2](#));
- key performance indicator monitoring (see [19.3](#));
- compliance audit process (see [Clause 20](#)).

These methods can be used to identify where aspects of the well integrity management system can be improved.

### 19.2 Performance review

The Well Operator **shall** conduct performance reviews to assess the application of the WIMS to a defined well stock.

The primary objectives of a performance review are to

- assess how well the WIMS is performing in accordance with its objectives;
- assess how well the WIMS processes adhere to the policies, procedures and standards defined in the WIMS;
- identify areas of improvement.

Where areas for improvement are identified, any changes required to address these improvements should be specified and implemented. Implementation of any changes **shall** follow the risk assessment and management of change processes as described in [Clauses 8](#) and [17](#), respectively.

It is recommended that the well stock included within the scope of the review should normally comprise a group of wells at a particular location, production facility or field but, where deemed appropriate, the well stock may be a smaller group of wells or even an individual well.

Such reviews **shall** be performed at a defined frequency as determined by the Well Operator based upon associated risks.

In addition, ad hoc reviews **shall** be performed as and when deemed necessary when new information becomes available that can have a significant impact on well integrity risk or assurance processes.

The review **shall** be performed by a group of personnel who are deemed competent in well integrity management and who are familiar with the Well Operator WIMS. It is recommended that, where practicable, at least some personnel involved in the reviews should not be directly involved in well integrity management of the well stock under review in order to provide a broader perspective and to aid in identifying any issues that can have been overlooked by those who are engaged in day-to-day operation of the wells under review.

It is recommended that, in performing the review, the Well Operator should typically assess the following.

Performance factor	Performance review activity
Compliance	Check that policies, procedures and processes are up-to-date, approved for use and being consistently applied.
	Compare current documented well operating limits(s) against the current in-service condition/use of the wells.
	Check that the wells are currently operating within their defined envelopes particularly if well condition/use has changed or original planned well design life has been exceeded.
	Examine changes to well operating limits since the last review and reasons for these changes.
	Check whether the well operating limits(s) are approaching a condition where they cannot support the continued use of the well (including any potential to exceed the original planned well design life).
	Examine actual monitoring, testing and maintenance frequencies against planned frequencies to check whether planned frequencies are being achieved or, where applicable, that a deviation from a planned frequency has been justified, documented and approved.
Documentation	Check that WIMS activities are clearly and adequately documented in accordance with any defined requirements and the documentation is readily available to relevant personnel.
Governance	Check that specified levels of authority for any approval processes are being correctly applied within the WIMS.

Performance factor	Performance review activity
Measurement	Review well integrity key performance indicators. Identify any trends and areas of the WIMS that can require modification to address any deficiencies indicated by the trends.
	Check that any WIMS audit findings, if applicable, are being adequately addressed and where necessary, identify areas where this is not the case.
	Check on type and quantity of reported non-conformances and incidents associated with well integrity and where applicable, identify changes to the WIMS to avoid such issues in future.
Organizational capability	Check that relevant personnel clearly understand their involvement in well integrity management processes and that they are competent to fulfil the requirements specified in the WIMS.
	Check that adequate resources are assigned to address all the elements of the WIMS in accordance with defined requirements.
Relevance	Check that WIMS processes are up-to-date and applicable to the well stock being assessed.
	Examine basis for current documented operating limits, performance standards and monitoring, testing and maintenance processes. Assess whether any changes to the WIMS are required to capture <ul style="list-style-type: none"> <li>— enhancements to current the Well Operator policies and procedures and risk management principles and practices;</li> <li>— current legislative requirements;</li> <li>— any new internal or industry guidance, learning’s, experience or best practices identified since the last review;</li> <li>— any supplier recommendations/notifications regarding equipment use or replacement/obsolescence since the last review;</li> <li>— availability, since the last review, of new or improved techniques or technologies that might enhance well integrity if applied to the well stock.</li> </ul>
Risk and Reliability	Check whether risk assessments are being performed in accordance with defined standards and procedures, all relevant risks have been identified, the magnitude of the risks are correctly defined and risk mitigation requirements have been implemented.
	Check that risks are being managed effectively in accordance with defined standards and procedures.
	Examine numbers and types of well anomalies encountered since the last review. Examine failure and corrective maintenance trends relative to planned monitoring, testing and maintenance frequencies.
	Check whether the current reliability and condition of the well stock is aligned to the current frequency of planned monitoring, testing and maintenance of the well components.
Timeliness	Check on timeliness of addressing well anomalies relative to defined requirements and, where applicable, identify any processes within the WIMS that can be modified to enhance timeliness while still meeting defined requirements.

### 19.3 Key performance indicator monitoring

**19.3.1** Key performance Indicators (KPIs) represent defined metrics associated with the elements of the well integrity management system described in 5.2 plus any other elements defined by the Well Operator.

Setting, tracking and regularly reviewing these metrics aids in

- determining the effectiveness of the well integrity management system as currently implemented;
- identifying general trends regarding the reliability of the well stock;

- identifying general trends regarding the well integrity risk posed by the well stock.

**19.3.2** The Well Operator should determine KPIs and a suitable review frequency that are appropriate to track the effectiveness of their particular WIMS. These should normally be based on metrics that are aligned to critical objectives of the WIMS.

Typical KPIs should be trended and may typically include

- number of well anomalies (relative to total number of wells) versus time and/or versus cumulative production/injection (can be tracked for each anomaly type);
- mean time to failure (can be tracked for each anomaly type);
- time taken to address well anomalies (can be tracked for each anomaly type and/or by level of risk);
- mean time to repair/replace/abandon (can be tracked for each anomaly type and/or by level of risk);
- number of non-conformances to the WIMS that have been identified (e.g. during compliance audits, well reviews and assurance processes) relative to the number of wells, which can include metrics based on the percentage of wells in compliance with planned monitoring, testing, maintenance and repair/replacement schedules;
- percentage number of wells operating under a deviation versus time;
- percentage of wells of the total well stock in compliance with preventive corrective tasks, annular pressures MAASP and corrosion monitoring plans;
- total number of wells completed, flowing, closed in and suspended versus total number of wells being managed in the well integrity management system;
- number of wells operating under a dispensation or derogation;
- well failures as a percentage of the total well stock;
- percentage of wells of total well stock with annulus pressure anomalies;
- percentage of wells in non-compliance with monitoring plans
- measures of well integrity management performance against the plan, e.g. inspections and tests completed vs. planned;
- repairs and work-over's completed vs. planned;
- staffing of relevant key positions and competence levels;
- underlying causes of each failure mode as a percentage of all failure modes.

This allows monitoring of both the performance of well integrity activities and their effectiveness in maintaining and improving integrity.

## 20 Compliance audit

### 20.1 General

The Well Operator **shall** establish an audit process to demonstrate compliance with the well integrity management system. The audit reports should provide clear indication as to which sections of the WIMS are functioning adequately, and which sections need further action.

## 20.2 Audit process

Each element of the WIMS (as identified in [5.2](#)) should be the subject of an audit. The Well Operator **shall** establish the frequency of audits or as required by local regulation.

Each audit should have a clearly defined the terms of reference focused on testing compliance with the WIMS and the effectiveness of meeting the objectives of the WIMS.

The audit objectives, scope and criteria has to be agreed in advance.

The audit team leader is responsible for performing the audit and should be independent from the work process being audited.

The resultant audit report should identify any observed deficiencies and make recommendations to address such deficiencies.

The Well Operator management team responsible for well integrity should review the audit recommendations, assign and track action items as appropriate.

Guidelines for an auditing process can be found in ISO 19011.

## Annex A (informative)

### Well integrity roles and responsibilities chart

[Table A.1](#) provides an example of a RACI chart, showing who is responsible (R), accountable (A), consulted (C) or informed (I).

**Table A.1 — Example of a roles and responsibility over view**

No.	Activity	Well engineering	Production operations	Production technology	Well integrity authority
1	Well charter/field development plan	C	—	AR	I
2	Well specification	C	—	AR	I
3	Well detailed design	AR	—	C	I
4	Construct well	AR	—	C	I
5	Calculate and set annulus maximum allowable annulus surface pressures (MAASPs)	R	—	AR	I
6	Prepare handover documents	AR	I	C	—
7	Complete and validate well status	AR	I	C	—
8	Confirm as build specification	C	C	AR	I
9	Sign off handover document	R	A	C	I
10	Define operating envelope Calculate high-pressure alarm (HPA) and triggers	I	C	AR	C
11	Monitor well and annuli	—	AR	C	—
12	Manage annulus pressure	—	AR	C	—
13	Carry out well maintenance (preventative and corrective)	R	AR	C	C
14	Conduct annulus investigation	C	R	A	C
15	Carry out MAASP/ trigger re-calculation	R	C	A	C
16	Conduct well integrity review	C	C	AR	C
17	Monitor compliance with WIMS Requirements	—	C	C	A
18	Review, maintain, and update process	I	I	I	AR
19	Well abandonment	R	A	C	C

<sup>a</sup> Definitions: R indicates "responsible", A indicates "accountable", C indicates "contribution", and I indicates "information"

## Annex B (informative)

### Example of competency matrix

<b>Well Integrity competence matrix (example)</b>					
No.	Activity	Operator	Well services	Well / Petroleum Engineer	Subject matter expert
1	Monitor well pressures within envelop	Skill	Skill	Knowledge	Skill
2	Operate well head & X mass tree valves	Skill	Skill	Knowledge	Skill
3	Operate and equalize subsurface safety valves	Skill	Skill	Knowledge	Knowledge
4	Test Well head and X mass tree valves	Skill	Skill	Knowledge	Knowledge
5	Test subsurface and surface safety valves	Skill	Skill	Knowledge	Skill
6	Monitor annular pressures	Skill	Skill	Knowledge	Skill
7	Bleed down and top up annular pressures	Skill	Skill	Knowledge	Skill
29	Assess well operating envelop	knowledge	Skill	Skill	Skill
8	Maintain and grease well head and X mass tree valves	Knowledge	Skill	Knowledge	Knowledge
9	Repair / replace well head and X mass tree valves	Awareness	Skill	Knowledge	Knowledge
10	Repair and replace Subsurface safety valves	Awareness	Skill	Knowledge	Knowledge
11	Install and remove Well head plugs (BPV)	Awareness	Skill	Knowledge	Knowledge
12	Install and remove Well head VR plugs	Awareness	Skill	Knowledge	Knowledge
13	Back seat valves and repair stem seals	Awareness	Skill	Knowledge	Knowledge
14	Un-sting and bleed valve pressure	Awareness	Skill	Knowledge	Knowledge
15	Test well head hanger seal	Awareness	Skill	Knowledge	Knowledge
16	Re-energise well head hanger neck seal	Awareness	Skill	Knowledge	Knowledge
17	Pressure test annulus	Awareness	Skill	Knowledge	Skill
18	Pressure test tubing	Awareness	Skill	Knowledge	Skill
19	Install down hole isolation plugs	Awareness	Skill	Knowledge	Skill
20	Calculate Maasp	Awareness	Knowledge	Skill	Skill
21	Recalculate Maasp	Awareness	Knowledge	Skill	Skill
22	Annulus investigation	Awareness	Knowledge	Knowledge	Skill
23	Review further use ( life cycle extension )	Awareness	Knowledge	Knowledge	Skill
24	Replace X mass tree	Awareness	Skill	Knowledge	Knowledge
25	Run corrosion logs	Awareness	Skill	Skill	Knowledge
26	Asses corrosion logs	Awareness	knowledge	Skill	Skill
27	Kill well	Awareness	Skill	Skill	Knowledge
28	Assess well barrier diagram	knowledge	Skill	Skill	Skill
30	Risk assess and process deviations	knowledge	knowledge	knowledge	Skill

**Figure B.1 — Example of competency matrix**

## Annex C (informative)

### Barrier element acceptance table

**Table C.1 — Example of a barrier element acceptance table (adapted from NORSOK D010r3)**

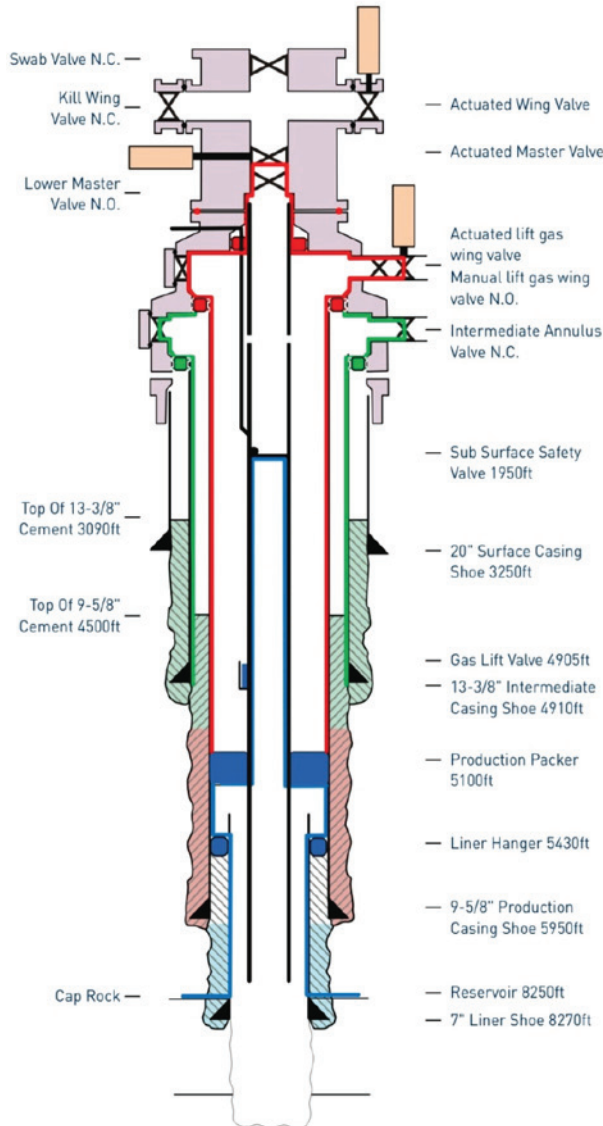
Features	Acceptance criteria	References
<b>A. Description</b>	This describes the WBE in words.	—
<b>B. Function</b>	This describes the main function of the WBE.	—
<b>C. Operating Limits</b>	<p>For WBEs that are constructed in the field (i.e. drilling fluid, cement), this should describe:</p> <ul style="list-style-type: none"> <li>— 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;</li> <li>— construction requirements for how to actually construct the WBE or its sub-components, and will in most cases consist only of references to normative standards.</li> </ul> <p>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.</p>	Name of specific references
<b>D. Initial test and verification</b>	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.	—
<b>E. Use</b>	This describes proper use of the WBE in order for it to maintain its function and prevent damage to it during execution of activities	—
<b>F. Monitoring</b>	This describes the methods for verifying that the WBE continues to be intact and fulfils its design/selection criteria during use.	—
<b>G. Failure modes</b>	This describes conditions that impair (weaken or damage) the function of the WBE, which can lead to implementing corrective action or stopping the activity/operation.	—

## **Annex D** **(informative)**

### **Well barrier schematic**

[Figure D.1](#) shows an illustrative well barrier schematic to identify the barrier envelopes and the well barrier elements.

ABC Oil and Gas Operator				
XYZ Field	Well: AA-01	Prepared by:	Date:	— Primary Well Barrier to the Reservoir
Welltype: Gas Lifted Oil Producer		Approved by:	Date:	— Secondary Well Barrier to the Reservoir, also Primary Barrier to the Lift Gas
Date Original Well Completed		X-mas Tree is rated to:	psi	— Secondary Well Barrier to the Lift Gas
Date Workover 1 Completed		Wellhead is rated to:	psi	A-annulus MAASP:
Date Workover 2 Completed		Tubing is rated to:	psi	B-annulus MAASP:
Drawing Ref:	Rev:	N.O. = Normally Open N.C. = Normally Closed		C-annulus MAASP:
Current Well Status: Producing with Lift Gas				Date:



**Barrier Element Table**

**Primary Well Barrier to Reservoir**

Barrier Element	Element Verification
Cap Rock	Xxx Equivalent Mud Wt s.g.
7" Liner Cement	TOC xxx ft: Total Cmt length xxx ft
7" Liner Hanger/Packer	PT to xxx psi w/ MW yy s.g.
7" Liner	PT to xxx psi w/ MW yy s.g.
9-5/8" Casing (below Packer)	PT to xxx psi w/ MW yy s.g.
9-5/8" Production Packer	PT to xxx psi w/ MW yy s.g.
Gas Lift Valve	PT to xxx psi w/ MW yy s.g.
4-1/2" Tubing	PT to xxx psi w/ MW yy s.g.
TR SSSV Flapper	PT to xxx psi w/ MW yy s.g.

**Secondary Well Barrier to the Reservoir**

Barrier Element	Element Verification
9-5/8" Casing Shoe Strength	Xxx Equivalent Mud Wt s.g.
9-5/8" Cement inside 13-3/8"	TOC xxx ft: Total Cmt length xxx ft
9-5/8" Casing	PT to xxx psi w/ MW yy s.g.
9-5/8" Casing Hanger seals	PT to xxx psi w/ MW yy s.g.
9-5/8" Wellhead section	PT to xxx psi w/ MW yy s.g.
9-5/8" Wellhead Annulus Valves	PT to xxx psi w/ MW yy s.g.
Tubing Hanger Seals	PT to xxx psi w/ MW yy s.g.
X-mas Tree Connector	PT to xxx psi w/ MW yy s.g.
Hydraulic Master Valve	PT to xxx psi w/ MW yy s.g.

**Secondary Well Barrier to the Lift Gas**

Barrier Element	Element Verification
13-3/8" Casing Shoe Strength	Xxx Equivalent Mud Wt s.g.
13-3/8" Cement	TOC xxx ft: Total Cmt length xxx ft
13-3/8" Casing	PT to xxx psi w/ MW yy s.g.
13-3/8" Casing Hanger seals	PT to xxx psi w/ MW yy s.g.
13-3/8" Wellhead section	PT to xxx psi w/ MW yy s.g.
13-3/8" Wellhead Annulus Valves	PT to xxx psi w/ MW yy s.g.

**Well Integrity Notes:**

1. the 410ft of cement overlap inside the 13-3/8" is considered good cement

**Figure D.1 — Well barrier schematic**

## Annex E (informative)

### Example — Performance standard for well safety critical elements

<b>Example Performance standard Well Integrity (not exhaustive)</b>			
<b>Minimum Acceptance Criteria</b>	<b>Assurance Measure</b>	<b>Units of Measure</b>	<b>Example</b>
<b>Well Head/Tree Visual Inspection</b> There shall be no leaks/weepers of the well head/tree, valve and instrument connections. (Visual Inspection)	Acceptable visual inspection	No leaks	Zero
<b>Wellhead/Tree valve operability</b> All wellhead/tree valves shall be operable in accordance with manufacturer defined specifications (number of turns)	Acceptable test / operate on demand as per manufacturer specification	Number of turns	18 3/4 turns
<b>Wellhead/Tree valve Actuation</b> Actuated wellhead/tree valves shall close within the required time as defined by operator in the well hook up cause and effect requirements for shutdown based on API 14.	Acceptable response test	Time	30 seconds
<b>Wellhead/Tree valve Leakage Rate</b> The valve leakage rate is not greater than the corresponding allowable leakage rate as specified by operator based on API 14	Acceptable test / leak rate	Ambient volume/ time	0,425M3/min
<b>Annular Safety Valve integrity</b> The ASV performs within the parameters specified by the operator based on API 14	Acceptable test Operates on demand records available	Pressure limit	xx Bar hg
<b>Annulus Integrity Management (1)</b> The annulus pressures are to be within specified values for Maximum Allowable Annulus Surface Pressure (MAASP)/Trigger and Minimum Values	Operates within MAASP records available	Pressure limit	xx Bar hg
<b>Annulus Integrity Management (2)</b> The annulus pressure monitoring equipment is calibrated correctly and alarms (where fitted) operate at the required set points or pressures are recorded manually on regular intervals.	Acceptable test Operates on demand records available	Accuracy	Percentage
<b>Annulus Integrity Management (3)</b> The annulus pressures test is to be within the wells operating envelop as defined by Operator	Acceptable test Operates on demand records available	Pressure test	xx Bar hg
<b>Sub Surface Safety Valves (SSSVs) Integrity</b> The SSSV performs within the parameters specified by Operator	Acceptable test Operates on demand	Leak test	0,425M3/min
<b>Well Plug(s) Integrity Test</b> The well plugs perform within the parameters specified by operator	Acceptable test Operates on demand	Leak test	0,425M3/min
<b>Gas Lift Valve (GLV) / Tubing Integrity Test</b> The GLVs and tubing perform within the parameters specified by Operator	GLV Tubing to annulus test acceptable	Inflow test	0,425M3/min
<b>Hanger neck seal, control line feed through, electrical feed through and DASF / adaptor spool seal area's</b> The component pressures test is to be within the wells operating envelop as specified by Operator. Shutdowns of ESP's / Beam pumps / ESPCP's / PCPS / jet pumps gas lift systems, that have capability to overpressure flow line / wellheads or other well components, shutdown test is to be within	Acceptable test Operates on demand	Pressure test	xx Bar hg
<b>Shutdowns of ESP's / Beam pumps / ESPCP's / PCPS / jet pumps gas lift systems.</b> Artificial lift systems that have capability to overpressure flow line / wellheads or other well components, shutdown test is to be within defined cause and effect diagram parameters.	Acceptable test Operates on demand	shutdown test	30 seconds
<b>Location safety valve or production wing valve:</b> Operates as defined in cause and effect s diagram as defined by well operator	Acceptable test Operates on demand	shutdown test	30 seconds
<b>Operating envelop of Injection wells:</b> Maximum allowable injecting pressure as defined by Operator	Operating limit of pressure of injection pressure based on Maasp of well bore	Pressure limit	xx Bar hg
<b>Steam wells</b> Maximum allowable pressure / temperature as defined by Operator	Operating limit of pressure of injection pressure / temperature based on Maasp & temperature limitations of well bore	Pressure + Temperature limit	xx Bar hg / deg Celcius

**Figure E.1 — Example of performance standard for well safety critical elements**

## Annex F (informative)

### Well barrier elements, functions and failure modes

[Table F.1](#) lists the types of well barrier elements (WBEs), with a description of their function and typical failure modes, that are relevant during the operational phase.

Other WBEs that are not listed below may be employed in wells and, should that be the case, a similar documented evaluation should be made for these.

**Table F.1 — Well barrier elements, their functions and failure modes**

ELEMENT TYPE	FUNCTION	FAILURE MODE (Examples)
Fluid column	Exerts a hydrostatic pressure in the well bore that prevents well influx/inflow of formation fluid.	Leak-off into a formation Flow of formation fluids
Formation strength	Provides a mechanical seal in an annulus where the formation is not isolated by cement or tubulars  Provides a continuous, permanent and impermeable hydraulic seal above the reservoir  Impermeable formation located above the reservoir, sealing either to cement/annular isolation material or directly to casing/liner  Provides a continuous, permanent and impermeable hydraulic seal above the reservoir	Leak through the formation  Not sufficient formation strength to withstand annulus pressure  Not sufficient formation strength to perform hydraulic seal
Casing	Contains fluids within the wellbore such that they do not leak out into other concentric annuli or into exposed formations	Leak at connections  Leak caused by corrosion and/or erosion  Parted connections
Wellhead	Provides mechanical support for the suspending casing and tubing strings  Provides mechanical interface for connection of a riser, BOP or production Christmas tree  Prevents flow from the wellbore and annuli to formation or the environment	Leaking seals or valves  Mechanical overload
Deep-set tubing plug	Provides a mechanical seal in the tubing to prevent flow in the tubing	Leaks across the seals, internal or external
Production packer	Provides a mechanical seal between the completion tubing and the casing/liner, establishing the A-annulus above and thus preventing communication from the formation into the A-annulus	Leak across the external packing elements  Leak across the internal seals
Surface-controlled sub-surface safety valve	Safety valve device installed in the production tubing string that is held open, usually by the application of hydraulic pressure in a control line. If there is loss of control line hydraulic pressure, the device is designed to close automatically	Lack of control line communication and functional control  Leaking above acceptance criteria  Failure to close on demand  Failure to close within the acceptable closing time

Table F.1 (continued)

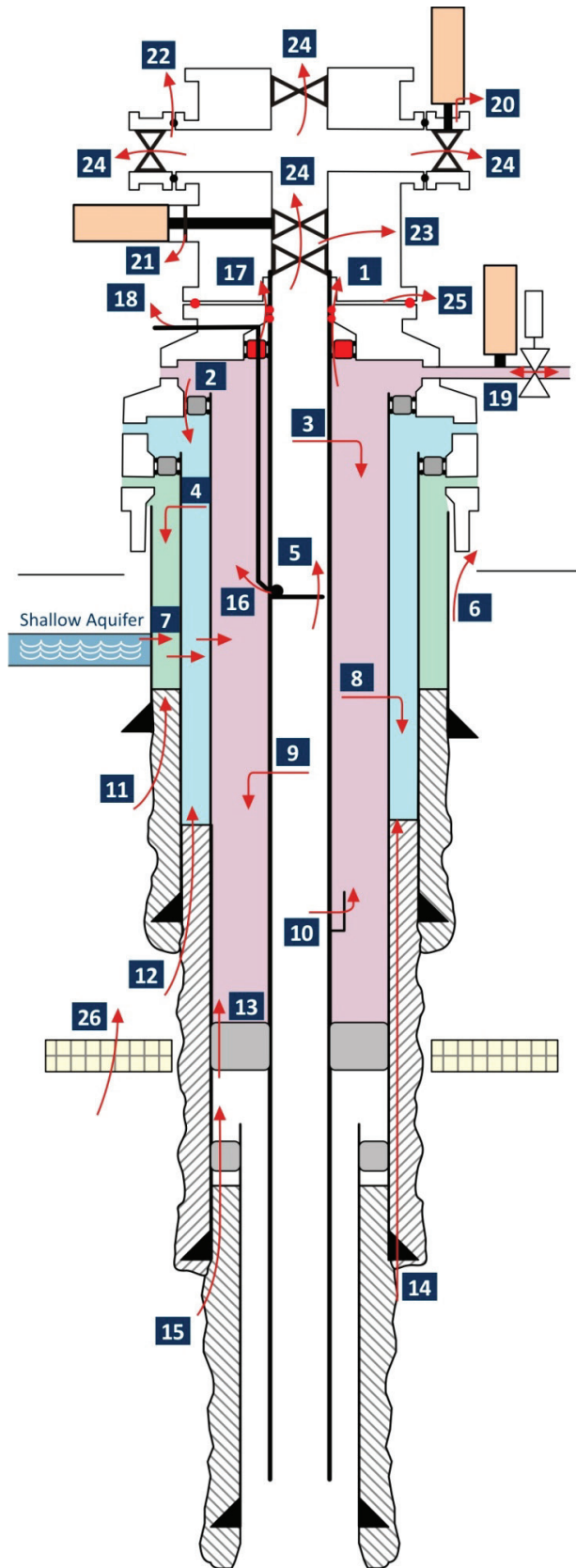
ELEMENT TYPE	FUNCTION	FAILURE MODE (Examples)
Liner top packer	Provides a hydraulic seal in the annulus between the casing and the liner, to prevent flow of fluids and resist pressures from above or below	Inability to maintain a pressure seal
Sub-sea production Tree	System of valves and flow conduits attached to the well-head at the sea floor, which provides a method for controlling flow out of the well and into the production system  Additionally, it may provide flow paths to other well annuli.	Leaks to the environment Leaks above the acceptance criteria Inability of valves to function Mechanical damage
Annulus surface-controlled sub-surface safety valve	Safety valve device installed in the annulus that prevents flow of fluids from the annulus to the annulus wing valve	Lack of control line communication and functional control  Leaking above acceptance criteria  Failure to close on demand  Failure to close within the acceptable closing time
Tubing hanger	Supports the weight of the tubing and prevents flow from the tubing to the annulus or <i>vice versa</i>	Leak past tubing seal  Mechanical failure
Tubing hanger plug	Mechanical plug that can be installed within the tubing hanger to allow for isolation of the tubing  Often used to facilitate the installation of BOPs or Christmas tree repairs	Failure to hold pressure, either internally or externally
Wellhead/annulus access valve	Provides ability to monitor pressure and flow to/from an annulus	Inability to maintain a pressure seal, or leaking above acceptance criteria  Unable to close
Casing/liner cement	Cement provides a continuous, permanent and impermeable hydraulic seal along well bore between formations and a casing/liner or between casing strings.  Additionally, the cement mechanically supports the casing/liner and prevents corrosive formation fluids coming into contact with the casing / liner.	Incomplete fill of the annulus being cemented, longitudinally and/or radially  Poor bond to the casing/liner or formations  Inadequate mechanical strength  Allows flow from/to formations behind the casing/liner
Cement plug	A continuous column of cement within an open hole or inside casing/liner/tubing to provide a mechanical seal	Poor placement, leading to contamination with other fluids in the well  Insufficient mechanical strength  Poor bond to the casing or formation
Completion tubing	Provides a conduit for fluid to/from the reservoir to/from surface	Leak to or from the annulus.  Wall thinning from corrosion and/or erosion not resistant to the load cases
Mechanical tubing plug	A mechanical device installed in completion tubing to prevent the flow of fluids and resist pressure from above or below, inside tubulars and in the annulus space between concentric positioned tubulars.	Inability to maintain a pressure seal.

Table F.1 (continued)

ELEMENT TYPE	FUNCTION	FAILURE MODE (Examples)
Completion string component	Provides 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, chemical injection mandrels, etc.	Inability to maintain differential pressure Valves leaking above the acceptance criteria
Surface safety valve(s) or emergency shut-down (ESD) valves	Provides shut-down functionality and isolation of well to production process/flow lines based on operating limits of the production system	Leaks to environment Leaks across valves above acceptance criteria Mechanical damage Inability to respond to process shutdown requirement over pressuring process
Surface production Tree	A system of valves and flow conduits attached to the well head that provides a method for controlling the flow out of the well and into the production system	Leaks to the environment Leaks across valves above the acceptance criteria Inability to function valves Mechanical damage

**Annex G**  
(informative)

**Example of possible well leak paths**



- 1** Tubing Hanger/Sea Leak
- 2** Wellhead Seal Leak
- 3** Tubing Leak Above SSSV
- 4** Intermediate Casing Leak
- 5** SSSV Leak
- 6** External Leak Or Seep Outside Conductor
- 7** External Corrosion from Aquifer
- 8** Production Casing Leak
- 9** Tubing Leak Below SSSV
- 10** Leak Through The SPM Accessory
- 11** Leak into an Outer Annulus From Casing Shoe
- 12** Leak Into B - annulus From Casing Shoe
- 13** Leak Around the Production Packer
- 14** Leak Via Through Poor Cement or Micro Annulus Channel
- 15** Leak through the Liner Hanger or Liner Cement
- 16** Hydraulic Control Line Leak to A - annulus
- 17** Hydraulic Leak Line At Xmas Tree Void/Tubing Hange
- 18** Leak At Wellhead Outlet
- 19** Leaks through Xmas Tree and Wellhead Valves to or from the Process Facilities
- 20** Stem Packing Leak
- 21** Bonnet Seal Leak
- 22** Flange Leak
- 23** Xmas Tree Body Leak
- 24** Xmas Tree Valve Leak
- 25** Xmas Tree Connector Leak
- 26** Leak Through Cap Rock

Note: Often two or more simultaneous modes of failure can complicate diagnosis, and also lead to a significant worsening of the Well Integrity condition.

Figure G.1 — Well diagram showing some typical modes of well failure

## Annex H (informative)

### Example of leak testing gas lift valves

Rigorous inflow testing or leak testing of *in situ* gas lift valves to compare with the API benchmark leak rate of 15 scf/min is difficult and time consuming due to

- the very low leak rate (15 scf/min) compared to the large gas filled production annulus volume;
- temperature effects that potentially mask the observed pressure changes;
- presence of check valves that can prevent reverse flow;
- complex manifolds and valve arrangements that make it difficult to determine where leaks are originating.

If it is necessary to carry out this rigorous testing, an example method is outlined below. However the methodology can be applied only when gas is leaking into the gas lift valve. The method does not apply to liquid leaks. Therefore, it is necessary to take care to ensure that any liquids are bull-headed away before testing starts.

- a) To perform an inflow test on the gas lift valves, it is necessary that the pressure in the tubing exceeds the pressure in the annulus. To achieve this, the tubing is displaced to gas and the annulus pressure is bled off; this also ensures gas across the gas lift valve(s), at least initially. Shut-in the well at the choke and/or the flow wing valve.
- b) Allow the tubing pressure to build up to xx bar (see below). Consider also to bullhead gas into the tubing.
- c) Shut down and isolate the gas lift and allow the pressures to stabilize.
- d) Bleed off the annulus to a pressure less than 50 % of the SIWHP.
- e) Observe the annulus pressure and from the pressure build-up calculate the combined leak rate of the gas-lift valves.

As shown [Figure H.1](#), the higher the tubing pressure, the more the fluid is pushed back into the formation. Ideally, the shut-in tubing pressure should be such that the fluid level is between the gas injection valve and the top perforation, although over-displacement of gas into the reservoir does not pose any problems. This would give the maximum tubing pressure for performing the test and, if there is a leak at one of the gas-lift valves, it is certain that the leak is gas and not liquid. This allows making the correct leak-rate calculation. If liquids leak through the gas lift valve or the packer into the gas filled annulus, they will go unnoticed, except when the leak is very large. Attempt to keep a constant gas pressure on the tubing to ensure that the liquid level is maintained below the gas lift valves.

This approach does require an understanding of the reservoir pressure.

The difficulty in the interpretation of the data of this type of gas lift valve leak test is the large volume of the annulus. For example, for a 4-1/2" x 9-5/8" annulus with a capacity of 30 l/m, the size of the annulus can easily be in the order of 50m<sup>3</sup> to 75 m<sup>3</sup>. A leak rate of 15 scf/min gas into a 60 m<sup>3</sup> annulus, it will take 3 h to result in a 100 kPa (1 bar) pressure increase. An increase of the average gas temperature in the annulus of 6 °C results in a similar pressure increase. So, to be able to accurately determine the leak rate, it is important that the gas temperature is stable during the test or that the temperature can be accurately monitored with surface and down-hole gauges so that corrections for temperature changes can be made.

Inflow test gaslift valves

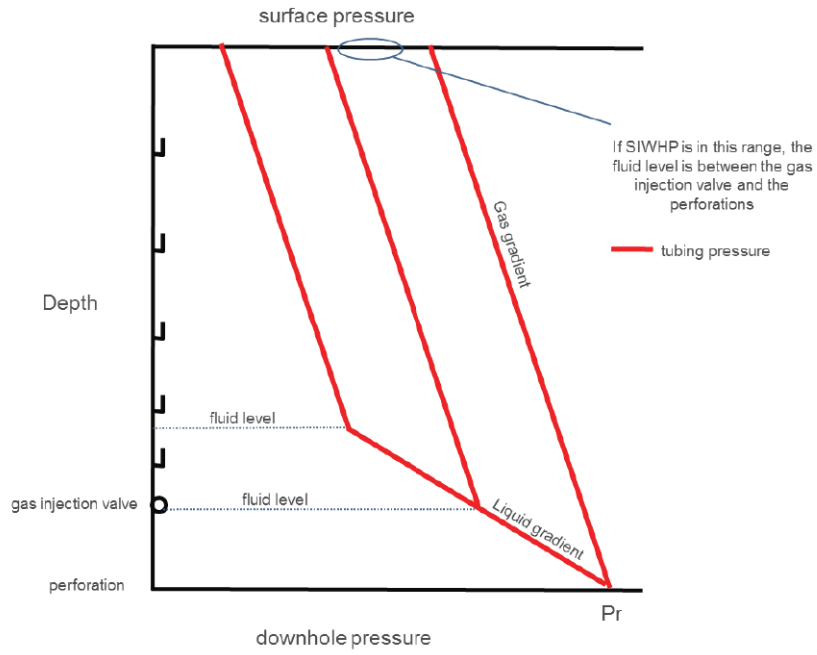


Figure H.1 — Inflow test gas-lift valves

## Annex I (informative)

### Leak rate determination calculations

#### I.1 Water leaking into or from a water-filled cavity

The leakage rate,  $Q$ , expressed in cubic metres per minute (cubic feet per minute), of water leaking into or from a water-filled cavity can be calculated from Formula (I.1):

$$Q = C_W \cdot V \cdot dP/t \quad (I.1)$$

where

$$C_W = -\frac{1}{V} \cdot \frac{dV}{dP}$$

- $C_W$  is the water compressibility factor, equal to  $4,5 \times 10^{-4} \text{ MPa}^{-1}$  ( $3,1 \times 10^{-6} \text{ psi}^{-1}$ );
- $V$  is the cavity volume, expressed in cubic metres (cubic feet);
- $dV$  is the size of the leak, cubic metres (cubic feet);
- $dP$  is the pressure change, expressed in mega Pascal's (pounds per square inch);
- $t$  is the test duration, expressed in minutes.

**EXAMPLE** Pressure test of Christmas tree cavity with water:

For the conditions:

Volume of Christmas tree and test line: 0,008 m<sup>3</sup> (0,283 ft<sup>3</sup>)

Test duration: 15 min

Pressure at the beginning of the test: 34,5 Mpa (5 000 psi)

Pressure at the end of the test: 26,2 MPa (3 800 psi)

$$\begin{aligned} dV &= C_W \cdot V \cdot dP \\ &= 29 \times 10^{-6} \text{ m}^3 \text{ per 15 min} \\ &= (1019 \times 10^{-6} \text{ ft}^3 \text{ per 15 min}) \\ Q &= 2,0 \cdot 10^{-6} \text{ m}^3 / \text{min} \\ &= (68 \cdot 10^{-6} \text{ ft}^3 / \text{min}) \end{aligned}$$

**NOTE 1** For  $V$  and  $dV$ , any (more practical) unit can be used as long as it is consistent.

**NOTE 2** The value of  $C_W$  is not constant, but varies with pressure and temperature. For the numbers used in the example, the error in the calculated leak rate within 10 %.

For other liquids, the calculation method is similar but the correct value for the compressibility of the liquid should be used. Note that the compressibility of oil,  $C_0$ , (as obtained from a PVT analysis) can be as much as 5 times greater than  $C_W$ .

NOTE 3 Water leaking at  $4 \times 10^{-6} \text{ m}^3/\text{min}$  gives a similar pressure increase to oil leaking at  $20 \times 10^{-6} \text{ m}^3/\text{min}$ .

NOTE 4 For a similar leak rate, the pressure increase for water is 5 times larger than for oil.

## I.2 Gas leaking into or from a gas filled cavity

The gas leak rate,  $q$ , expressed in standard cubic metres per minute (standard cubic feet per minute)  $Q = 2 \text{ sm}^3/\text{min}$  can be calculated from Formula (I.2) for SI units and from Formula (I.3) for USC units, which follow directly from the equation of state,  $PV = ZnRT$ :

$$q = 2,84 \cdot 10^3 \left( \Delta \frac{p}{Z} \right) \left( \frac{1}{t} \right) \left( \frac{V}{T} \right) \quad (\text{I.2})$$

$$q = 35,37 \left( \Delta \frac{p}{Z} \right) \left( \frac{1}{t} \right) \left( \frac{V}{T} \right) \quad (\text{I.3})$$

where

$$\Delta(p/Z) = \left( \frac{p_f}{Z_f} \right) - \left( \frac{p_i}{Z_i} \right)$$

$p_i$  and  $p_f$  are the initial and final pressures, respectively;

$Z_i$  and  $Z_f$  are the initial and final values of the gas compressibility factor,  $Z$ , respectively;

$p$  is the pressure, expressed in mega Pascal's (pounds per square foot);

$Z$  is the gas compressibility factor;

$t$  is the test duration, expressed in minutes;

$V$  is the isolated observed volume, expressed in cubic metres (cubic feet);

$T$  is the absolute temperature of the gas in the observed volume, expressed in degrees Celsius (degrees Fahrenheit).

NOTE It is assumed that there is no significant change in the temperature during the test.

EXAMPLE 1 Inflow test of 4" lower master valve

For the conditions:

Isolated Christmas tree volume:  $0,008 \text{ m}^3$  ( $0,28 \text{ ft}^3$ )

Test duration: 5 min

Pressure at the beginning of the test: 1,00 MPa (145 psi)

Pressure at the end of the test: 3,00 MPa (435 psi)

Temperature:  $27 \text{ }^\circ\text{C}$  ( $81 \text{ }^\circ\text{F}$ )

$Z_i = 0,98$

$Z_f = 0,93$

Thus,

$$q = 0,033 \text{ sm}^3 / \text{min}$$
$$= 1,17 \text{ sft}^3 / \text{min}$$

EXAMPLE 2 Inflow test of 5" SCSSV at 200 m depth

For the conditions:

Isolated tubing and Christmas tree volume: 2,0 m<sup>3</sup> (70,7 ft<sup>3</sup>)

Test duration: 30 min

Pressure at the beginning of the test: 4,00 MPa (580 psi)

Pressure at the end of the test: 4.50 MPa (653 psi)

Temperature: 15 °C (59 °F)

$$Z_i = 0.88$$

$$Z_f = 0.87$$

Thus,

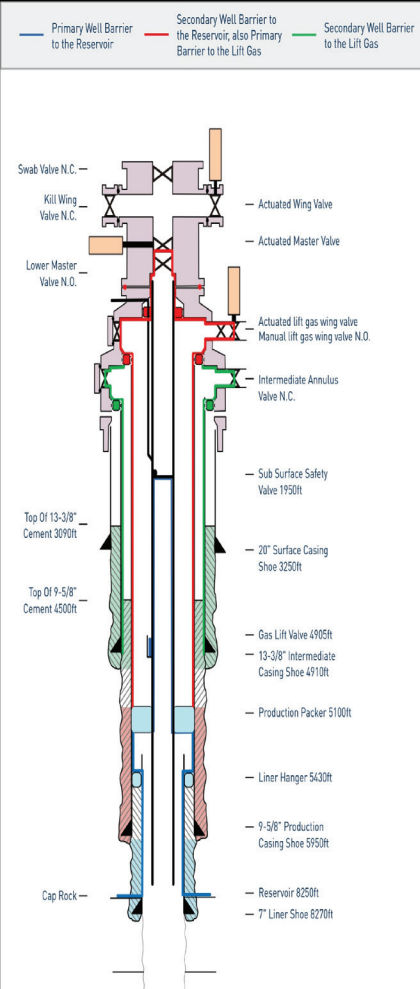
$$q = 0,41 \text{ sm}^3 / \text{min}$$
$$= 14,6 \text{ sft}^3 / \text{min}$$

**Annex J**  
(informative)

**Well operating limits**

**Table J.1 — Example of well operating limits**

Well Operating Limits						
	date of update data entry					
	Well name					
	Well type (Function)					
	Reservoir name					
	Future well function within original design limits					
	Original completion date					
	Well design life					
	Well schematic attached					
	Well head x mass tree					
	Identify any leaking or failed barrier components					
	<b>Additional notes:</b>					
	Any limitation on acceptable kill and completion fluids?					
	Any special monitoring requirements ?					
	Any other comments?					
	Operational limits for tubing (enter value or NA)	Long string	Short string			
		min/max	min/max			
	H2s					
	Co2					
	Oxygen in water injection					
	Maximum injection pressure					
	Gas oil ratio					
	Water cut					
	Fluid density					
	Gas density					
	Reservoir pressure					
	Reservoir temperature					
	Well shut in tubing head pressure					
	Maximum design production / injection rate fluid					
	Maximum design production / injection rate gas					
	Artificial lift device design rate					
	<b>Operational limits for annuli ( enter value or NA)</b>	<b>Annulus A</b>	<b>Annulus B</b>	<b>Annulus C</b>	<b>Annulus D</b>	
	MAASP					
	Upper trigger pressure					
	Lower trigger pressure					
	<b>Fluids</b>	<b>Annulus A</b>	<b>Annulus B</b>	<b>Annulus C</b>	<b>Annulus D</b>	<b>Long string</b>
	Fluid type mud / brine gradient					
	Degraded mud / base fluid gradient					
	Cement base fluid gradient					
	Fluid additives					
	Corrosion inhibitor					
	Scale inhibitor					
	Asphaltene inhibitor					
	Bactericide / Biocide					
	pH control additive					
	Oxygen scavenger					
	H2s scavenger					
	Lift gas inhibitor					
	Friction reducer					
	Foam agent injection					



## Annex K (informative)

### MAASP calculations

#### K.1 General

In this annex, the maximum allowable annulus surface pressure (MAASP) calculations for each critical point relevant in each annulus are detailed. These calculations are intended as a guide for a common well construction type. Each well construction type requires a rigorous review to ensure that all critical points have been identified and that the appropriate calculations are conducted.

The values used for burst and collapse pressure resistances of tubular goods should be based on the tri-axial calculation methods found in ISO/TR 10400 or API/TR 5C3 7th Edition and be adjusted for degradation due to wear, corrosion and erosion based on the service conditions and the Well Operator evaluation.

**NOTE** For the purposes of this provision, mud and base fluid densities assume that the annulus, or tubing, is full of a single fluid. However, in cases where the annulus or tubing contains several fluids, or phases, the calculations should be adjusted to account for these density variations.

The MAASP value to select for operational usage is the lowest value obtained from each of the calculations.

[Table K.1](#) gives the symbols and abbreviations used in the equations.

Alternative MAASP calculation methodologies utilizing tri-axial stress analysis are available using various software packages which take into account a wider range of inputs such as the axial load on tubulars (which impacts their collapse/burst resistance) and temperature de-rating of material properties. MAASP calculations in operational wells need to consider the impact of reduced wall thickness in tubulars as a consequence of wear, corrosion or erosion.

Table K.1 — Symbols and abbreviations used in MAASP calculations

Parameter		Description
Symbol	Abbreviation	
$D_{TVD}$	D	True vertical depth (TVD), expressed in metres Depth is relative to the wellhead and not the rotary kelly bushing
$\nabla P_{BF}$	BF	Base fluid pressure gradient in annulus, expressed in kilopascals per metre
$\nabla P_{EMM}$	MM	Equivalent maximum mud pressure gradient, expressed in kilopascals per metre
$P_{MAASP}$	MAASP	Maximum allowable annulus surface pressure, expressed in kilopascals
$\nabla P_{MG}$	G	Mud or brine pressure gradient, expressed in kilopascals per metre
$P_{PC}$	PC	Casing collapse pressure resistance, expressed in kilopascals Safety factor should be applied to PC prior to calculating the MAASP value
$P_{PB}$	PB	Casing burst pressure resistance, expressed in kilopascals Safety factor should be applied to PC prior to calculating the MAASP value
$P_{PKR}$	PKR	Production packer operating pressure rating, expressed in kilopascals
$\nabla S_{FS}$	FS	Formation strength gradient, expressed in kilopascals per metre
$\nabla P_{FP}$	FP	Formation pressure gradient, expressed in kilopascals per meter
$g_n$	—	Gravitational acceleration equal to 9, 806 654 8 m·s <sup>-2</sup> (after International Bureau of Weights and Measures)
Subscripts		Description
A, B, C, D		Designation of the annulus
ACC		Accessory (e.g. SPM or landing nipple)
BF		Base fluid (refers to base fluid of mud in outer casing)
RATING		Performance rating
FORM		Formation
LH		Liner hanger
PP		Production packer
RD		Rupture disk
SH		Casing shoe
SV		Safety valve
TBG		Tubing
TOC		Top of cement

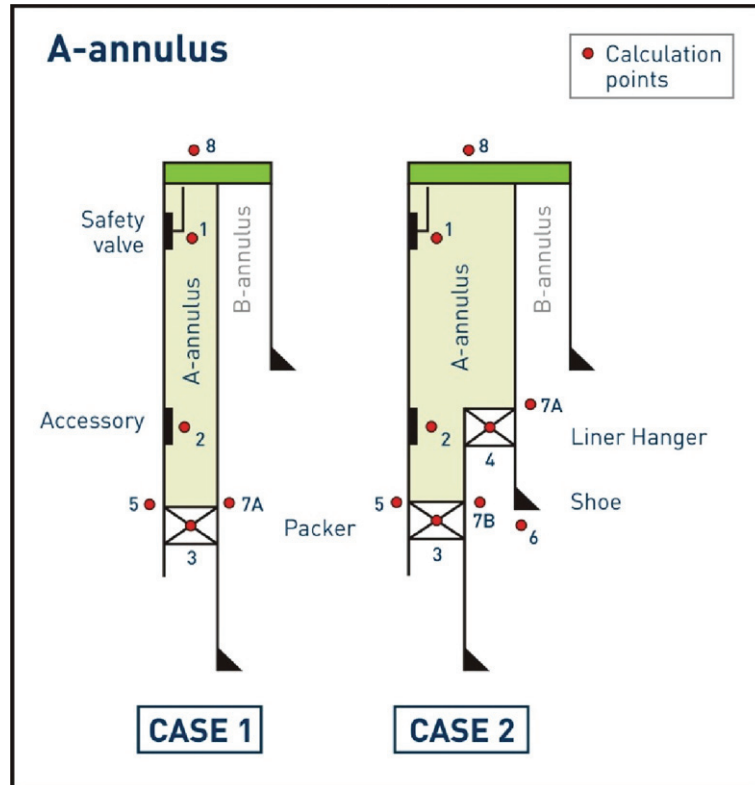
### K.2 Calculating MAASP values for the A-annulus

Two cases for the A-annulus are shown diagrammatically in [Figure K.1](#).

Calculation equations are given in [Table K.2](#).

-----  
 Production casing, long string

Production liner



NOTE For points 4 and 7B, pressure or maybe  $\rho P_{BF, B}$ , it is necessary to select lowest possible pressure at these points.

**Figure K.1 — Examples of two different A annuli, for calculating MAASP**

Table K.2 — MAASP calculation equations for A-annulus

Point	Item	Case	MAASP equations	Remarks/Assumptions
1	Safety valve collapse	Both	$P_{MAASP} = P_{PC,SV} - \left[ D_{TVD,SV} \cdot (\nabla P_{MG,A} - \nabla P_{MG,TGB}) \right]$	Highest MG in annulus Lowest MG in tubing
2	Accessory collapse	Both	$P_{MAASP} = P_{PC,ACC} - \left[ D_{TVD,ACC} \cdot (\nabla P_{MG,A} - \nabla P_{MG,TGB}) \right]$	Highest MG in annulus Lowest MG in tubing
3	Packer collapse	Both	$P_{MAASP} = P_{PC,PP} - \left[ D_{TVD,PP} \cdot (\nabla P_{MG,A} - \nabla P_{MG,TGB}) \right]$	Highest MG in annulus Lowest MG in tubing
3	Packer element rating	Both	$P_{MAASP} = (D_{TVD,FORM} \cdot \nabla S_{FS,FORM}) + P_{PKR} - (D_{TVD,PP} \cdot \nabla P_{MG,A})$	FP <sub>FORM</sub> is the lowest pressure from the formation immediately below the packer element in the life cycle PKR is the pressure rating of the packer element (can require de-rating during the life cycle)
3	Liner element rating	2	$P_{MAASP} = (D_{TVD,FORM} \cdot \nabla S_{FS,FORM}) + P_{PKR} - (D_{TVD,PP} \cdot \nabla P_{MG,A})$	FP <sub>FORM</sub> is the lowest pressure from the formation immediately below the packer element in the life cycle PKR is the pressure rating of the packer element (may need to be de-rated during the life cycle)
4	Liner hanger packer burst	2	$P_{MAASP} = P_{PB,LH} - \left[ D_{TVD,LH} \cdot (\nabla P_{MG,A} - \nabla P_{BF,B}) \right]$	Base fluid is assumed on the basis that the residual mud in the B-annulus has decomposed. It can be necessary to substitute BF <sub>B</sub> for a formation pressure under some circumstances.
5	Tubing collapse	Both	$P_{MAASP} = P_{PC,TBG} - \left[ D_{TVD,PP} \cdot (\nabla P_{MG,A} - \nabla P_{MG,TBG}) \right]$	Highest MG in annulus Lowest MG in tubing It can be necessary to adjust D <sub>PP</sub> for other depths relevant to check (for different tubing weight/sizes etc.).
6	Formation strength	2	$P_{MAASP} = D_{TVD,SH} \cdot (\nabla S_{FS,A} - \nabla P_{MG,A})$	If cement quality in the liner lap and annulus is uncertain use the liner hanger packer rating
<p><sup>a</sup> Point numbers correspond to red dots in <a href="#">Figure H.1</a>.</p>				

Table K.2 (continued)

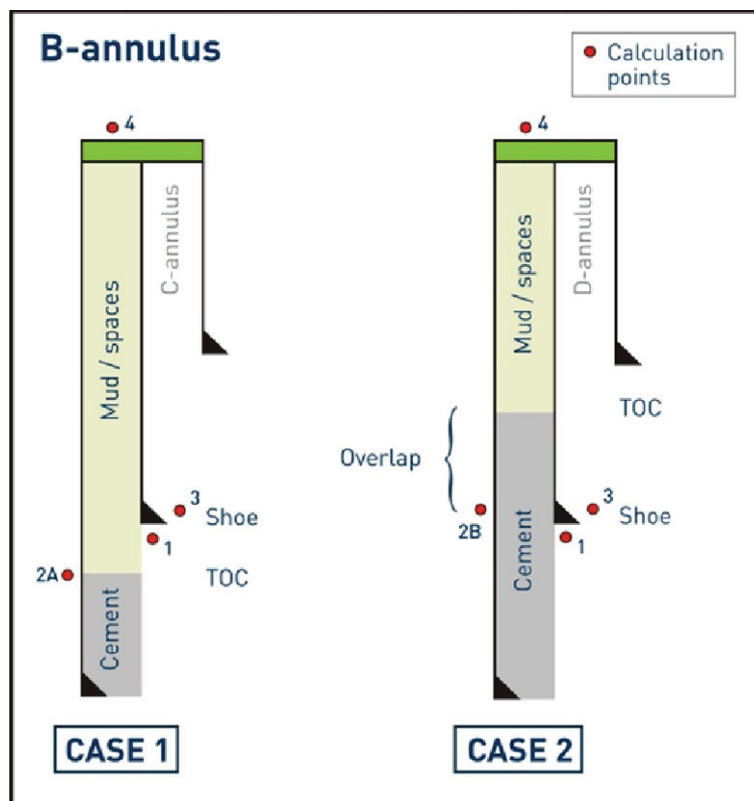
Point	Item	Case	MAASP equations	Remarks/Assumptions
7A	Outer (production) casing burst	1	$P_{MAASP} = P_{PB,B} - \left[ D_{TVD,LH} \cdot (\nabla P_{MG,A} - \nabla P_{BF,B}) \right]$	<p><math>P_{PB}</math> is the casing/liner burst of the outer casing of the annulus</p> <p>Use the deepest depth if the gradient <math>BF_B</math> is greater than <math>MG_A</math>. Otherwise <math>D_{TVD} = 0</math> should be used.</p> <p>It can be necessary to adjust <math>D_{PP}</math> or <math>D_{LH}</math> for other depths relevant to check (for different tubing weight/sizes etc.)</p>
		2	$P_{MAASP} = P_{PB,B} - \left[ D_{TVD,PP} \cdot (\nabla P_{MG,A} - \nabla P_{BF,B}) \right]$	
7B	Liner lap burst	2	$P_{MAASP} = P_{PB,B} - \left[ D_{TVD,PP} \cdot (\nabla P_{MG,A} - \nabla P_{BF,B}) \right]$	It can be necessary to substitute $P_{BF,B}$ for formation pressure in some circumstances
8	Wellhead rating	Both	MAASP is equal to the wellhead working pressure rating	—
—	Annulus test pressure	Both	MAASP is equal to the annulus test pressure	—
—	Casing rupture disc	—	$P_{MAASP} = P_{PB,RD} - \left[ D_{TVD,RD} \cdot (\nabla P_{MG,A} - \nabla P_{BF,B}) \right]$	—
<sup>a</sup> Point numbers correspond to red dots in <a href="#">Figure H.1</a> .				

It should be recognized that  $MG$  (for the inner string) and  $BF$  (for the outer annulus) may be set to zero to calculate the equivalent of an evacuated tubing or annulus, if it is not preferred to use a minimum pressure limit in the operating pressure envelope. Consequently, it is necessary that thermally induced effects are considered for closed volumes where the pressure cannot be independently controlled. Minimum pressure requirements for packer support still need to be determined.

Typical design practice is to use an evacuated tubing and annulus load scenario for the well barriers.

### K.3 Calculating MAASP values for the B-annulus

Two cases for the B-annulus are shown diagrammatically in [Figure K.2](#). Calculation equations are given in [Table K.3](#).



NOTE 1 Top of cement in B-annulus below the previous casing shoe (Case 1).

NOTE 2 Top of cement in B-annulus in the previous casing shoe (Case 2).

**Figure K.2 — Examples of two different B-annuli, for calculating MAASP**

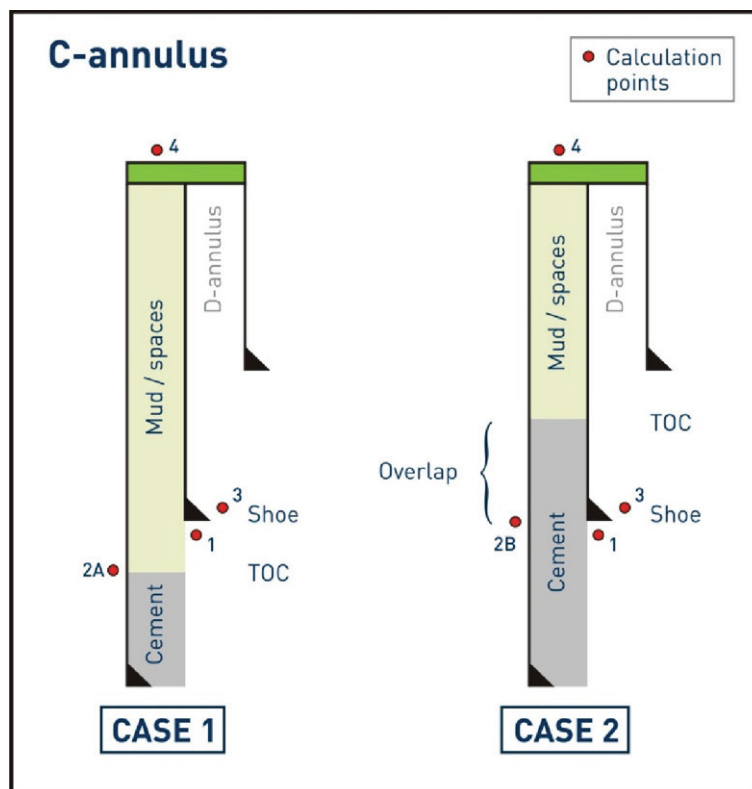
Table K.3 — MAASP calculation equations for B-annulus

Point <sup>a</sup>	Item	Case	MAASP equations	Remarks/assumptions
1	Formation strength	Both	$P_{MAASP} = D_{TVD,SH,B} \cdot (\nabla S_{FS,B} - \nabla P_{MG,B})$	It is necessary to account for degraded mud, cement spacers and washes.
2	Inner (production) casing collapse	Both	$P_{MAASP} = P_{PC,A} - [D_{TVD,TOC} \cdot (\nabla P_{MG,B} - \nabla P_{MG,A})]$	PC is the casing/liner collapse pressure resistance Highest MG in B-annulus Lowest MG in A-annulus (evaluate to use evacuated A case) $D_{TOC}$ to be adjusted for other depths relevant to check (for different casing weight/sizes etc.)
3	Outer casing burst	Both	$P_{MAASP} = P_{PC,B} - [D_{TVD,SH} \cdot (\nabla P_{MG,B} - \nabla P_{BF,C})]$	Use the deepest depth if the gradient in $BF_C$ is greater than $MG_B$ . Otherwise $D_{TVD} = 0$ . $D_{SH}$ to be adjusted for other depths relevant to the calculation (for different casing weight/sizes etc.)
4	Wellhead rating	Both	MAASP is equal to the wellhead working pressure rating.	—
—	Annulus test pressure	Both	MAASP is equal to the annulus test pressure.	—
—	Casing rupture disc	—	$P_{MAASP} = P_{PB,RD} - [D_{TVD,RD} \cdot (\nabla P_{MG,B} - \nabla P_{BF,C})]$	—

<sup>a</sup> Point numbers correspond to red dots in [Figure K.2](#).

### K.4 Calculating MAASP values for the C-annulus and subsequent annuli

Two cases for the C-annulus are shown diagrammatically in [Figure K.3](#).



NOTE 1 Top of cement in C-annulus below the previous casing shoe (Case 1).

NOTE 2 Top of cement in C-annulus in the previous casing shoe (Case 2).

**Figure K.3 — Examples of two different C-annuli, for calculating MAASP**

Use the same calculation methodology for subsequent annuli as detailed for the B-annulus.

## Annex L (informative)

### Example — A change in MAASP calculation

In event of sustained annulus pressure and the Well Operator has confirmed the origin of source and pore pressure with the associated risk of loss of containment (subsurface) based on the shoe strength, the Well Operator may consider adjusting the MAASP based on the liquid level established which accounts for the gas column, as given in Formula (L.1):

$$P_{cs} = P_{ann} + (\rho_{gas} + h_{gas}) + (\rho_{mud} + h_{mud}) + (\rho_{cem} + h_{cem}) \quad (L.1)$$

where

- $P_{cs}$  is the pressure of the casing shoe, expressed in expressed in kilopascals;
- $P_{cs}$  is the annular pressure, expressed in expressed in kilopascals;
- $\rho_{gas}$  is the density of the gas, expressed in expressed in kilopascals per meters;
- $h_{gas}$  is the height of the gas column, expressed in meters;
- $\rho_{mud}$  is the density of the mud, expressed in expressed in kilopascals per metre;
- $h_{mud}$  is the height of the mud, expressed in meters;
- $\rho_{cem}$  is the density of the cement make up water, expressed in expressed in kilopascals per metre;
- $h_{cem}$  is the height of the cement, expressed in meters;

The source of the sustained annulus pressure should be assessed based on finger print sample compared with the original mud logging data.

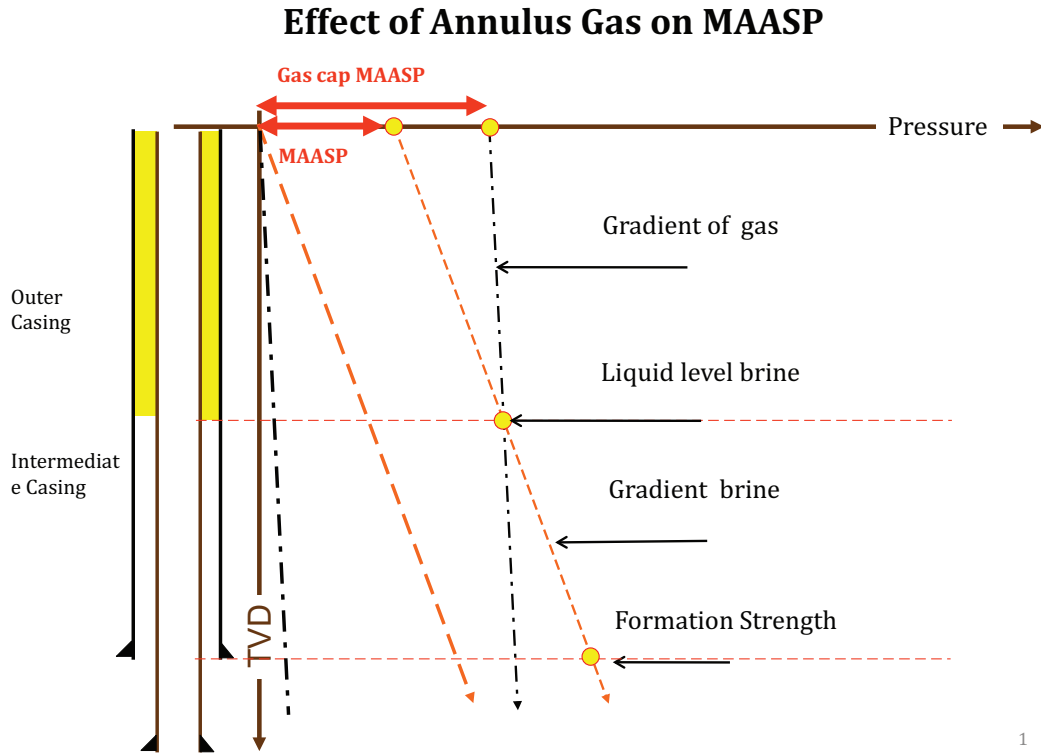


Figure L.1 — Effect of annulus gas on MAASP

When changing the MAASP value based on sustained annular gas pressure following should be considered:

- origin of the sustained pressure source, composition and its pore pressure;
- accurate liquid/gas interface depth / size of the gas cap in the annulus;
- gas cap or fluid level, which should be limited to less than  $\pm 60\%$  of the total shoe depth to avoid gas reaching to the casing shoe;
- build-up rate of the sustained annular pressure, which is typically limited to 25,5 sm<sup>3</sup>/h.

This calculation does not account for any potential loss of liquid to the formation that can change the pressure regime. That is to say, it is necessary to review the formation permeability and not just the formation strength.

## Annex M (normative)

### Information required of well handover

During the handover of a well, any deviations from the intended well design or changes of the operating limits **shall** be addressed and mitigated as part of managing the well during its lifecycle.

**Table M.1 — Well handover information**

## Handover from Well Construction to Production

Item description	Recommended/mandatory
<b>1. Well location</b>	
Country	<b>Recommended</b>
Lats/Longs, UTM Co-ords/UWI	<b>Recommended</b>
License No/Permit No/Block No/Slot	<b>Recommended</b>
On/Offshore	<b>Recommended</b>
RT Elev MSL/Water depth	<b>Recommended</b>
TD (MD & TVD)	<b>Recommended</b>
Drilled by, dates & rig	<b>Recommended</b>
Handover date and signatures	<b>Mandatory</b>
State or Government notification details (if required)	<b>Recommended</b>
<b>2. Well type</b>	
Well designation (Exp/App/Dev)	<b>Recommended</b>
Well design type (Production or Injection)	<b>Recommended</b>
<b>3. Well construction and flow assurance details</b>	
Detailed casing schematic to include; Casing weight, sizes, Grades, and Thread Types.	<b>Mandatory</b>
Cement (Cement types, tops, volume pumped/returned in each string), number and location of centralisers.	<b>Mandatory</b>
Detailed completion schematic complete with depths (TVD and MD) plus tubing details (tubing weights/sizes/threads/grades), cross over + component details (type/model/manufacture & part numbers, pressure rating & thread types)	<b>Mandatory</b>
Christmas Tree and Wellhead schematic to show key components (Valves + blocks) & include; manufacturer, valve size, type, PSL rating, valve serial number manual/hydraulic, turns to open/close OR seconds to close for actuated valves, bore size, pressure rating, grease type and volume in each chamber, pressure test certificates.	<b>Mandatory</b>
SCSSSV data - Type, size, rating, valve serial number, bore size, hydraulic fluid type and volume	<b>Mandatory</b>
SCSSSV data - valve signature curve	<b>Mandatory</b>
Annulus fluids (Fluid details; type & volumes, details of inhibitors & scavengers).	<b>Mandatory</b>
MAASP (including the basis for calculation on each annulus) and maximum allowable tubing pressures.	<b>Mandatory</b>
Well barrier envelope showing, primary and secondary barriers their status, identification of each well barrier element its depth and associated leak or function or pressure test verification of component parts. Any failed or impaired well barrier element shall be clearly identified.	<b>Mandatory</b>
Deviation data (angle/MD/TVD, horizontal section, number of junctions)	<b>Recommended</b>
Final Well Status at Handover (detail procedures or work that maybe required to start up a well - remove plugs, barriers)	<b>Mandatory</b>
Fish (Provide details of any fish left in the well including depths and sizes)	<b>Recommended</b>
Final well status at abandonment (casing tops, cement plug details to include volumes, tops, pressure test details)	<b>Recommended</b>
Seabed and site survey (wet trees only)	<b>Recommended</b>
<p>Note. Whenever ANY changes are made, the drawing must be updated complete with; <b>revision number, date, verified by and approved by details</b></p>	

**Table M.2 — Well handover information (continued)**

Item description	Recommended/mandatory
<b>4.0 Well design considerations</b>	
Designed well life, years	<b>Mandatory</b>
Design production/injection flowrates (G/O/W)	<b>Recommended</b>
Well operating envelope complete with associated derogation or dispensation support documentation	<b>Mandatory</b>
Sufficient details to ensure that the well start up procedures (production or injection) that account for sand/wax/hydrates as well as pressure and temperature changes on the tubing and annulus or any of the component parts.	<b>Recommended</b>
<b>5.0 Reservoir information</b>	
Perforations (MD and TVD + shot density, phasing, entry hole diameter, gun size, gun type)	<b>Recommended</b>
Reservoir pressure/temperature & depth/datum	<b>Recommended</b>
Paraffin	<b>Recommended</b>
Asphaltenes	<b>Recommended</b>
Hydrates	<b>Recommended</b>
Gas gravity	<b>Recommended</b>
Oil Gravity	<b>Recommended</b>
GOR	<b>Recommended</b>
<b>5.1 Produced Water (well test data if available)</b>	
Chlorides	<b>Recommended</b>
Barium	<b>Recommended</b>
Calcium	<b>Recommended</b>
Bicarbonate	<b>Recommended</b>
Scale risk	<b>Recommended</b>
NORM	<b>Recommended</b>
<b>5.2 Corrosion</b>	
H2S	<b>Recommended</b>
Co2 + partial pressure (if possible)	<b>Recommended</b>
<b>6.0 Well Intervention Monitoring</b>	
PLT/CET/Caliper/Camera	<b>Recommended</b>

Note. Whenever ANY changes are made, the drawing must be updated complete with; **revision number, date, verified by and approved by details**

## Annex N (informative)

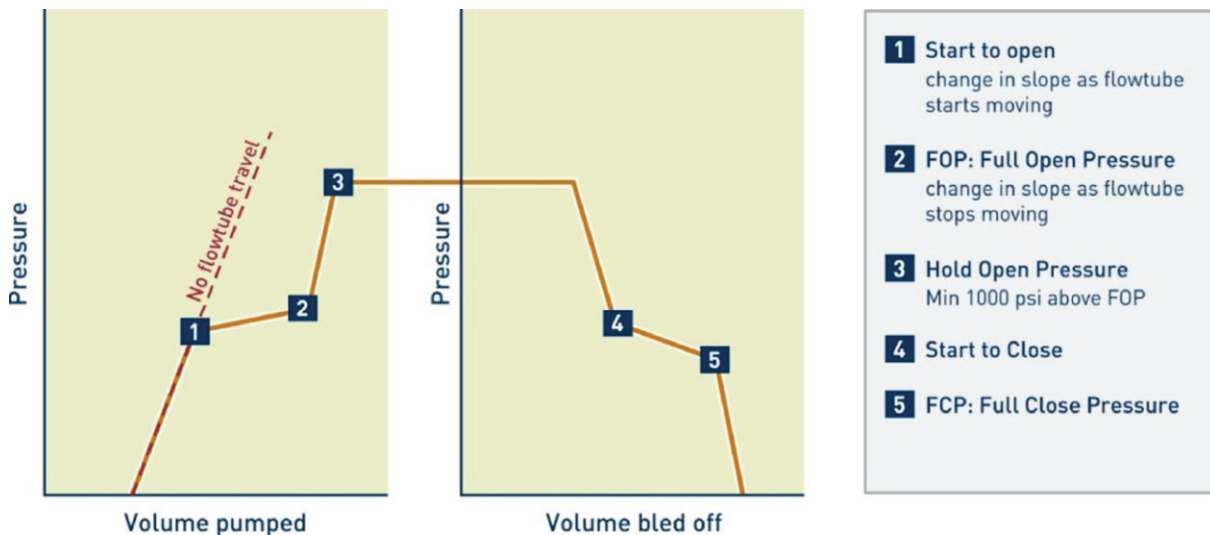
### Function testing by analysing hydraulic signature

#### N.1 Valve signature

The hydraulic signature of a valve is the pressure response when (slowly) pumping or bleeding off control line fluid. Analysing this hydraulic signature can reveal mechanical problems.

#### N.2 SCSSV

[Figure N.1](#) shows the typical signature of an SCSSV. The change in the slope of the curve indicates that the flow-tube is moving. If there is no indication of flow-tube travel and a correspondingly smaller hydraulic volume pumped, the flow-tube can be stuck.



**Figure N.1 — Typical signature of an SCSSV**

A good hydraulic signature, however, is no guarantee that the valve is functioning correctly as the flow tube and the flapper are not connected. If the flapper is stuck, or the torsion spring that assists flapper closure is broken, the flow tube can move all the way up to the closed position (resulting in a good hydraulic signature) but the flapper remains open. Therefore, analysing the hydraulic signature of an SCSSV does not prove flapper closure. The only way to prove that a flapper is closed is to demonstrate that the well is unable to flow.

If the SCSSV is operated from a wellhead control panel, it can be difficult to obtain a clear hydraulic signature. Under these circumstances, the control line may be disconnected from the panel and hooked up to a small independent control panel (as used in well services) or even a hand pump.

### N.3 Subsea Christmas tree

Figure N.2 shows the hydraulic signature of the production wing valve of a subsea Christmas tree that is being opened. The drop of supply pressure and the time it takes for the valve to open are good indicators. They can be compared with the signature from the original installation and changes in the signature can be an indication that something is not functioning correctly.

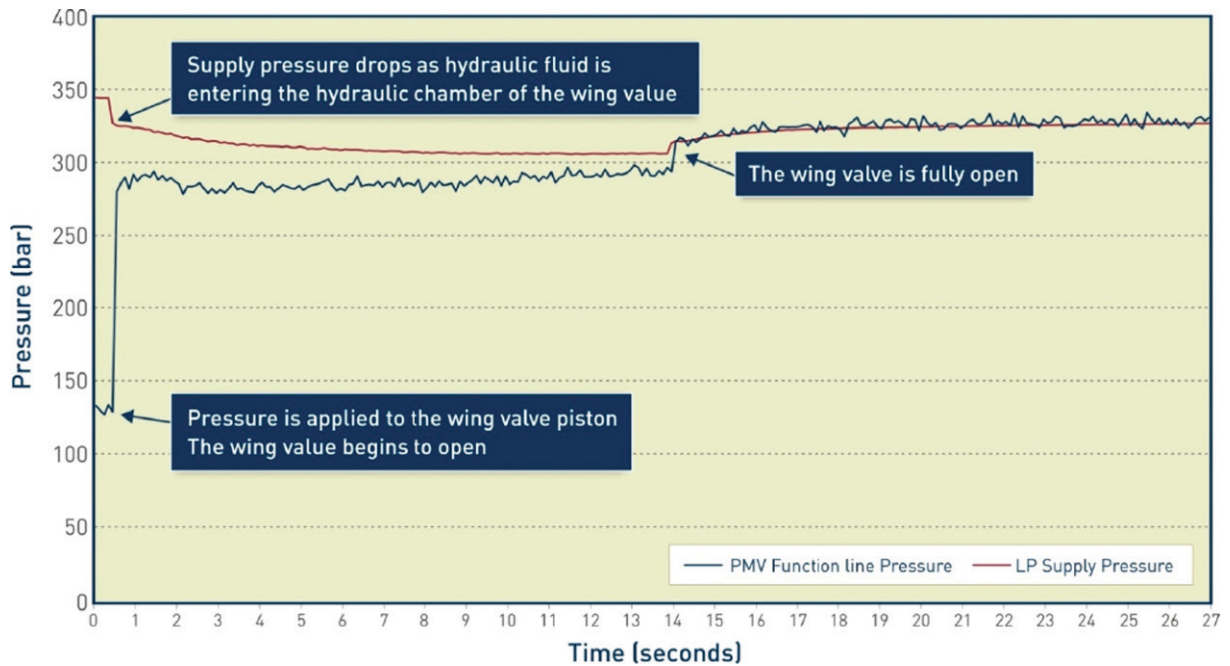


Figure N.2 — Signature of a production wing valve

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