Code of Practice: Well Integrity

NORTHERN TERRITORY GOVERNMENT

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Acronyms	Full form
ALARP	As low as reasonably practicable
CO_2	Carbon dioxide
DLPE	Department of Lands, Planning and Environment
DME	Department of Mining and Energy
FMP	Field Management Plan
H_2S	Hydrogen sulfide
HPHT	High pressure high temperature
LEL	Lower explosive limit
MAOP	Maximum allowable operating pressure
MD	Measured depth
PSIP	Petroleum Surface Infrastructure Plan
TVD	True vertical depth
WBE	Well barrier element
WBEAC	Well barrier element acceptance criteria
WBIV	Well barrier integrity validation report
WOMP	Well Operations Management Plan

Contents

1. Foreword

This *Code of Practice: Well Integrity* (Code) has been approved and gazetted by the Minister for Mining and Energy (Minister) in accordance with section 117AZV of the *Petroleum Act 1984* (Petroleum Act).

This Code shall be considered and addressed in any Well Operation Management Plan (WOMP) submitted to the Minister for assessment and approval. As such, this Code is applicable to all petroleum operations and well types, including exploration, appraisal, development, monitoring, injection and production wells in conventional and unconventional resources.

This Code replaces Part B (Well Operations) of the *Code of Practice for Onshore Petroleum Activities in the Northern Territory* that was jointly approved in May 2019 by the (then) Minister for Primary Industry and Resources and Minister for Environment and Natural Resources.

1.1. Legislative requirements for well integrity

The Petroleum Act, the *Petroleum Regulations 2020* (Regulations) and the *Petroleum (Environment) Regulations 2016* (collectively the Petroleum Legislation) regulate the exploration and production of onshore petroleum in the Northern Territory (NT).

The Petroleum Legislation was substantially amended between 2019 and 2023. From an operational perspective, two of the most significant amendments were the introduction of a mandatory code (or codes) of practice and the repeal of the *Schedule for onshore petroleum exploration and production* in favour of requirements for resource management, activity and infrastructure plans and regulations.

With regards to wells, section 60(1) of the Petroleum Act establishes that a WOMP is required to demonstrate how well activities will be appropriately managed over the entire life cycle of the well, including in relation to drilling, well construction, operation, re-entry, modification, decommissioning and post-decommissioning period to ensure that the risks to the integrity of the well are reduced to as low as reasonably practicable (ALARP).

Section 61A(1)(a) of the Petroleum Act establishes that the Minister cannot approve a WOMP unless satisfied that the plan has been prepared in accordance with any approved code of practice, which now refers to this Code.

Regulation 66AA(1) and Schedule 4B of the Regulations establishes the information that shall be included in a WOMP. This includes detail on how technical, operational and organisational solutions will be applied to maintain well integrity and ensure the successful extraction of petroleum over the life cycle of the well. A WOMP shall include a description of the well integrity management system which informs the WOMP, including advice on how the system is taken to comply with International Standard; *ISO 16530-1:2017 Petroleum and natural gas industries – Well integrity – Part 1: Life cycle governance* (ISO 16530). This Code has been developed in consideration of life cycle governance specified in ISO 16530 so as to facilitate compliance with the Regulations.

1.2. Complying with this Code

This Code specifies a range of mandatory requirements that shall be addressed and incorporated into a WOMP. Mandatory requirements are denoted by the word ‘shall’. This Code also contains a range of recommendations which are advised, but not required, to conform to this code for example. These are denoted by the word ‘should’ or ‘may’. ‘Can’ is used to denote a possible course of action or a demonstration of capability. For example, in relation to surface WBEs this Code specifies:

'Wells and well components shall be protected against surface formation instability and constructed to enable the circulation of drilling fluid from the well before surface casing is installed. A conductor casing string may be used'.

'The WOMP shall describe how surface formation instability will be managed and circulation of drilling fluid achieved before installation of the surface casing for subject wells'.

An interest holder may submit an application for the approval of a WOMP that proposes a method of achieving compliance with the Act and Regulations that is inconsistent with the contents of this Code. In such circumstances, the application shall highlight the inconsistency and comprehensively demonstrate how the proposal's risks are ALARP and acceptable. The approval of any such WOMP is at the Minister or their delegate's discretion.

This Code includes multiple normative references that shall be used to achieve compliance. This includes:

- standards published by the International Organization for Standardization (ISO),
- specifications, standards and recommended practices published by the American Petroleum Institute (API), and
- standards and recommended practices published by the Norwegian petroleum industry (NORSOK and Offshore Norge).

For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

Refer to section 1.10 for a list of normative references. All normative references are available for inspection free of charge during business hours at the Department of Mining and Energy (DME) offices, Level 3, Paspalis Centrepoint, 48-50 Smith Street Mall, Darwin NT 0800.

Section 117AZW of the Petroleum Act establishes that if a person allegedly contravenes a provision of the Act, including the requirement for compliance with a WOMP, this Code is admissible in the proceeding as evidence of whether or not a requirement under the Act was complied with. This Code can be used to establish the alleged contravention, if a provision of this Code is relevant to the alleged contravention and the person failed to observe that provision.

Interest holder's responsibility

This Code prescribes minimum standards for particular aspects of petroleum operations. Nothing in this Code reduces the ultimate responsibility that the interest holder has for carrying out their operations with reasonable diligence and in accordance other requirements of the Petroleum Legislation.

Section 5(1) of the Petroleum Act defines good oilfield practice, in relation to the exploration for, or operations for the recovery of, petroleum, as practices and procedures that are generally accepted as good and safe. This Code may be taken to supplement this meaning, but does not purport to be an exhaustive statement of what may be considered to be good oilfield practice under the Petroleum Act.

Section 61F of the Petroleum Act establishes that an interest holder shall take reasonable steps to identify and assess any hazard or risk that might compromise the integrity of a well (or surface infrastructure) and also implement and maintain measures to eliminate or control such hazards or risks. Application of this Code should meet or exceed the requirements of section 61F of the Petroleum Act.

1.3. Complying with the WOMP Content Guideline

Section 61(3) of the Petroleum Act establishes that an application for the approval of a WOMP shall also comply with any guidelines published by the Minister from time to time.

The Guideline provides advice on the requirements of the Petroleum Act and Regulations when applying for and complying with a WOMP. The Guideline sets out the expected structure of an application for the approval of a WOMP with reference to Schedule 4B of the Regulations. The Guideline directly references this Code with regards to technical expectations associated with each life cycle phase of a well. This Code and the Guidelines should be used together in the preparation of a WOMP.

1.4. Complying with an approved WOMP

Once a WOMP has been approved, the interest holder shall comply with all aspects of the approved plan. In addition to determining well design, drilling, construction and operational specifications, this Code requires that a WOMP includes a well integrity verification, monitoring, surveillance and maintenance program for each well. These commitments shall be met and reported upon for the duration of a well's life cycle.

Regulation 66AAR of the Regulations requires the submission of a well barrier integrity validation report (WBIV) to the Minister within 30 days of completing a new well, installing, replacing, modifying, removing or revalidating a sub-surface well barrier in a previously completed well or upon the acquisition of evidence that a sub-surface well barrier has been degraded.

A WBIV is required to demonstrate how approved WBEs have been applied to maintain or achieve well integrity through the various life cycle phases.

1.5. Interaction between this Code and other relevant legislation

Any obligations placed on interest holder under other legislation take precedence over this Code. These may include, but are not limited to the:

a) *Petroleum (Environment) Regulations 2016*

b) *Environment Protection Act 2019*

c) *Work Health and Safety (National Uniform Legislation) Act 2011*

If there is any inconsistency between the requirements of this Code and these statutes, the requirements of these statutes prevail.

1.6. Joint regulators of the onshore petroleum in the NT

The Administrative Arrangements Order (No. 3) 2024 establishes Ministerial responsibility for the administration of relevant pieces of legislation, area and activities of government and administration of respective agencies.

Minister for Mining and Energy - DME

The Minister has been allocated the administration of the Petroleum Act with the exception of provisions relating to the environmental regulation of exploration and production of petroleum, environmental offences and royalties.

The Minister is responsible for the regulation and management of energy operations in the NT, including well integrity. The Petroleum Operations Unit of the Energy Development Branch, DME support the Minister by making recommendations on the assessment, approval, monitoring, inspection and investigation of well operations.

This Code establishes legislative requirements for well integrity required for effective regulation.

Environment Minister - DLPE

The Environment Minister and the Department of Lands, Planning and Environment (DLPE) have responsibility for provisions in the Petroleum Act that apply to environmental regulation of exploration for and production of petroleum. The Petroleum Operations Unit within the Environment Division, DLPE administer a separate code of practice relating to environmental management that directly informs the requirements for an Environment Management Plan.

Collaborative regulation

The establishment of separate codes under relevant requirement of the Petroleum Legislation provide clearer division of responsibility between the Ministers, and their supporting agencies. However, the linkages between well integrity and environmental management will continue to be collaboratively addressed by the respective agencies. The Petroleum Act also requires that the Minister and the Environment Minister shall consult with each other before establishing, varying or revoking a code of practice.

1.7. Making this Code and revision

The Minister may vary this Code from time to time. The current published version will be maintained on the agency website.

It is intended that a review of this Code be commenced within two years of gazettal and from then on every two years, or as needed for reasons such as changes in legislation, regulations and relevant standards.

1.8. Gazettal and publication

This Code came into effect on 25 February 2025, by way of Northern Territory Government Special Gazette.

1.9. Wells operations predating this Code

Well operations management plans (WOMPs) that were accepted for assessment prior to the establishment of this code will be assessed under the *Code of Practice: Onshore Petroleum Activities in the NT* (2019). Similarly WOMPs approved under that Code will remain in force until such time that the WOMP requires review.

Section 61B of the Act establishes that a WOMP shall be reviewed:

a) before the commencement of any new activity not covered by, or inconsistent with, the WOMP; or

b) before there is a significant change to the way risks to the integrity of a well are managed so as to be ALARP; or

c) as soon as practicable after the integrity of a well covered by the plan becomes subject to a significant new risk or a significantly increased level of risk; or

d) if the plan has been in operation for 5 years since it was approved without review, or since it was last reviewed; or

e) if the Minister directs that the plan shall be reviewed; or

f) if a review is required in prescribed circumstances.

An applicant may be able to construct a new well in accordance with a WOMP which pre-dates this Code, where it can be demonstrated that the well is on the same petroleum interest and has identical well criteria to those specified in the WOMP as an indication of risk profile.

1.10. Normative references

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

ISO 16530-1, *Petroleum and natural gas industries — Well integrity — Part 1: Life cycle governance*

ISO 10423, *Petroleum and natural gas industries — Drilling and production equipment — Wellhead and tree equipment*

ISO 10426-2, *Petroleum and natural gas industries — Cements and materials for well cementing — Part 2: Testing of well cements*

ISO 13679, *Petroleum and natural gas industries — Procedures for testing casing and tubing connections*

ANSI/NACE MR0175/ISO 15156, *Petroleum and natural gas industries — Materials for use in H_2S-containing environments in oil and gas production*

NORSOK D-010, *Well integrity in drilling and well operations*

117 – Offshore Norge, *Recommended guidelines for well integrity*

API Spec 5CT, *Specification for Casing and Tubing*

API Spec 6A, *Specification for Wellhead and Tree Equipment*

API Spec 7NRV, *Specification for Drill String Non-return Valves*

API RP 5C5, *Recommended Practice for Procedures for Testing Casing and Tubing Connections*

API RP 10B-2, *Recommended Practice for Testing Well Cements*

API RP 10D-2, *Recommended Practice for Centralizer Placement and Stop Collar Testing*

API RP 13B-1, *Recommended Practice for Field Testing Water-based Drilling Fluids*

API RP 13B-2, *Recommended Practice for Field Testing Oil-based Drilling Fluids*

API RP 90-2, *Recommended Practice for Annular Casing Pressure Management for Onshore Wells*

API Spec 16A, *Specification for Drill Through Equipment*

API Spec 16C, *Specification for Choke and Kill Equipment*

API Spec 16D, *Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment*

API Spec 16RCD, *Specification for Rotating Control Devices*

API Standard 53, *Well Control Equipment Systems for Drilling Wells*

API Standard 65-Part 2, *Isolating Potential Flow Zones During Well Construction*

1.11. Equivalent standards

An interest holder may propose an alternative standard to a standard required by this Code where the interest holder can demonstrate that the application of the alternative standard achieves a level of risk that is equal to or less than what would be achieved by applying the required standard.

2. Definitions

Active barrier:

A well barrier element that performs its function without requiring activation.

Air drilling:

A form of underbalanced drilling where the drilling fluid is predominantly air and/or inert gases.

Aquifer:

Aquifer is defined in section 4(1) of the *Water Act 1992* (NT).

For the purposes of this *Code*, and for the purpose of implementing aquifer protection requirements, an aquifer is defined as per the *Water Act 1992* (NT) and that which is currently supplying a beneficial use, or potentially being able to provide a beneficial use, as defined in section 4(3) of the *Water Act 1992* (NT).

The NT Government authority who determines whether an aquifer has a potential beneficial use is the Water Resources Division of DLPE.

Decommissioned:

Permanent abandonment of a well or a part of a well.

Deep-set barrier:

A barrier composed of WBE that are set in the well above and close to, or at, the cap rock of the flow zone they are isolating as practical, or a depth where it is possible to achieve an overbalance pressure with an hydrostatic column to counter act the maximum anticipated pressure from below.

Deep-set conductor:

A conductor that functions as a well barrier element to fluid flow for part of the well's lifecycle. A conductor that only functions to provide surface protection (as per section 6.2.5) is not a deep-set conductor.

Field management plan (FMP) (As defined by the Petroleum Act):

A plan, prepared by a licensee for a production licence, that demonstrates to the Minister that the licensee has a strategic plan for the life cycle of the field that will provide for the maximum economic recovery of petroleum, and will return the optimal value of the resource, including the optimal value to the Territory, after taking into account good oilfield practice and any other relevant factor under the Petroleum Act.

Flow zone:

Any zone in a well where the zone is able to sustain flow into the well when the wellbore pressure is less than pore pressure or out of the well when the wellbore pressure is greater than pore pressure, including:

Petroleum flow zone:

A flow zone that contains predominantly petroleum.

Other flow zone:

A flow zone that is not an aquifer or a petroleum flow zone. This includes but is not limited to saline groundwater and accumulations of non-hydrocarbon gases such as CO_2.

High potential flow zone:

A flow zone that is:

- a discovery of petroleum, or a petroleum pool, as defined by the Petroleum Act, and

- a flow zone that is overpressured and able to sustain flow of fluid, or
- a flow zone where the fluid is predominantly in the gas phase and able to sustain flow of fluid.

High pressure (As described by the Regulations):

Where the maximum anticipated surface pressure is greater or equal to 10,000 psi or 69 MPa, or needs the deployment of pressure control equipment with a rated working pressure in excess of 10,000 psi or 69 MPa.

High temperature (As described by the Regulations):

Where the undisturbed bottom hole temperature at prospective reservoir depth or total depth is greater or equal to 149 degrees Celsius or 300 degrees Fahrenheit.

Hydraulic fracturing (As defined by the Petroleum Act):

The underground petroleum extraction process involving the injection of fluids at high pressure into a geological formation to induce fractures that conduct petroleum for extraction.

Inactive well

A well that is not being actively used:

a) to obtain data;

b) for the production of petroleum; or

c) to maintain the production of petroleum.

In-situ barrier formation:

A formation that can be used as a WBE in a well whose purpose is to provide a permanent seal preventing flow. Analogous to cap-rock or sealing formation.

Interest holder (As defined by the Petroleum Act):

The holder of a petroleum interest.

Managed pressure drilling:

A drilling method where down hole annular pressures are managed during drilling operations by the application of surface back pressure.

Permanent barrier:

A verified barrier that will maintain a permanent seal. A fluid column is not considered as a permanent barrier.

Petroleum (As defined in the Petroleum Act):

a) a naturally occurring hydrocarbon, whether in a gaseous, liquid or solid state;

b) a naturally occurring mixture of hydrocarbons, whether in a gaseous, liquid or solid state; or

c) a naturally occurring mixture of one or more hydrocarbons, whether in a gaseous, liquid or solid state, with hydrogen, hydrogen sulphide, nitrogen, helium or carbon dioxide or any combination of them,

and includes a hydrocarbon as defined by paragraph (a), (b) or (c) that has been returned to a natural reservoir.

Petroleum pool (As defined by the Petroleum Act):

A naturally occurring discrete accumulation of petroleum.

Petroleum surface infrastructure plan (PSIP) (As defined in the Petroleum Act)**:**

A plan, prepared by a licensee for a production licence, that demonstrates to the Minister that petroleum surface infrastructure on the licence area will be appropriately designed, built, operated and decommissioned to ensure that petroleum recovered under the licence will be appropriately managed from the point of extraction at the wellhead to the point of removal from the licence area in order to secure supply and to return the optimal value of the resource, including the optimal value to the Territory, after taking into account good oilfield practice and any other relevant factor under the Petroleum Act.

Potential barrier:

A well barrier that needs to be functioned to control flow.

Reservoir (As defined by the Petroleum Act)**:**

Any subsurface formation or geological sequence containing a petroleum pool.

Shut-in:

A shut-in well is an inactive well with one or more valves closed to the direction of flow. Reinstatement of operation of the well is possible at any time by the operation of valves without the requirement for other forms of intervention, reconnection of equipment or control systems.

Suspended:

A suspended well is an inactive well with one or more temporary objects placed in the well to act as part of a well barrier between a reservoir (or petroleum bearing zones) and aquifers (or the surface where aquifers are not present).

Underbalanced drilling:

Drilling where the hydrostatic head of the drilling fluid is intentionally maintained at levels below pore pressure.

Validation:

Examination, testing, audit or review to confirm that the design, construction, and operation of an activity, product or service meets specified requirements. Requirements can be performance requirements, regulatory requirements (including this code), industry standards, and best practices.

Verification:

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

Well barrier:

A system of one or several well barrier elements that contain fluids within a well to prevent uncontrolled flow of fluids within, into or out of the well. In this Code well barriers mean physical barriers unless otherwise stated.

Well barrier element (WBE):

A verifiable physical element that in combination with other well barrier elements form a well barrier.

Well barrier integrity validation report (WBIV):

A report, as required by regulation 66AAR of the Regulations, that details information on a well's well integrity classification and data relating to integrity validation testing that has been carried out on the well.

Well control manual:

A document, as required by regulation 66AA of the Regulations, that outlines the measures and procedures the interest holder has in place for well control during well construction or intervention operations.

Well plan summary:

A document, as required by regulation 66AAK of the Regulations, that sets out the planned location and construction of the well relative to structural geological elements and summarises the potential risks posed by known geological hazards.

Well Operations Management Plan (WOMP) (As defined by the Petroleum Act)**:**

A plan, prepared by a permittee or licensee, that demonstrates to the Minister that well activities will be appropriately managed over the entire life cycle of the well, including in relation to drilling, well construction, operation, re-entry, modification, decommissioning and the post-decommissioning period, to ensure that the risks to the integrity of the well are reduced to ALARP.

3. Well basis of design

The interest holder shall be able to demonstrate that the basis of design for all wells and well activities allows for the identification of all foreseeable well integrity risks and sources of uncertainty.

3.1. General basis of design requirements

The WOMP shall summarise the basis of design for subject wells with the following information identified as a minimum:

a) General information about the wells,

b) Well location and targets,

c) Well objectives,

d) Planned lifecycle,

e) Geological prognosis,

f) Kick tolerance,

g) Inflow requirements,

h) Outflow requirements,

i) Maximum operating pressures,

j) Data acquisition requirements, and

k) Lifecycle production and injection characteristics.

3.2. Offset wells

The WOMP shall identify offset wells that have been used to inform the basis of design, and a summary of the data quality and uncertainty. An offset well is one where it can be reasonable to conclude that the subsurface geological and fluid properties are similar to the wells being drilled.

3.3. Tolerances for well parameters

The WOMP shall identify basis of design parameters for subject wells and how these parameters have been identified and the tolerances for these parameters:

a) that form the criteria for a well to be operated under a WOMP,

b) that would trigger the interest holder's management of change process, and

c) that have been considered in the WOMP and where conditions fall outside of those ranges during operations require the WOMP to be revised.

3.4. Geological prognosis

The WOMP shall have a geological prognosis for subject wells that identifies and describes the formations that are anticipated, how the geological prognosis was derived, any uncertainties in the prognosis and the implications of that uncertainty. The geological prognosis shall provide details of:

a) all formations that are anticipated during drilling, identifying:

    a. formations that are potential flow zones, including:

i. the type of flow zone,

ii. whether the flow zone has potential to impact on well integrity, and

iii. whether a flow zone will be grouped with other flow zones and the basis for that grouping.

b. formations that are reservoirs, identifying:

i. whether they are anticipated to contain a petroleum pool, and

ii. whether petroleum production is intended from that petroleum pool.

c. formations that are potential in-situ barrier formations,

d. formations that have the potential to impact well integrity and/or drilling operations due to their geomechanical or chemical properties, and

e. formations that contain CO_2, H_2S or other corrosive fluid or gas.

b) potential geological structures,

c) potential geological hazards,

d) the anticipated pore pressure and fracture gradient, and

e) the anticipated temperature gradient.

3.5. Collision risk

The potential for collisions between wells shall be assessed.

The WOMP shall identify whether there is a collision risk for subject wells.

4. Well design

4.1. Address basis of design

The well design shall address all identified conditions and risks relative to well objectives as determined in the basis of design (section 3).

4.1.1. Program of well activities

The well design shall include the program of well activities required to achieve well objectives throughout a well's lifecycle. The program of well activities shall include:

a) intended well activities,

b) how the well activities are consistent with any Field Management Plan (FMP) the wells are part of,

c) foreseeable alternative well activities, and

d) the circumstances that would require alternative well activities.

The WOMP shall describe the program of well activities for subject wells.

4.1.1.1. Well shut-in and suspension

A well shall only be placed in a shut-in or suspended condition in accordance with the program of well activities as documented in the WOMP.

4.1.1.1.1. Shut-in well maximum time-period

An inactive well shall only be left in a shut-in state for a period of time that is:

a) consistent with a FMP for production wells where shutting-in of wells is used as part of reservoir management, or

b) a maximum of 12 months in duration.

4.1.1.1.2. Suspended well maximum time-period

An inactive well shall not be left in a suspended state for an undefined period of time. A well shall only be left in a suspended state for a period of time that is:

a) described in the WOMP, or

b) a maximum of 36 months in duration.

4.1.1.1.3. Suspended well WOMP requirements

Where a WOMP covers the suspension of subject wells, the WOMP shall describe:

a) the circumstances that would require a well to be left in a suspended state,

b) the maximum time-period a well could be left in a suspended state,

c) justification for the maximum-time-period a well could be left in a suspended state, and

d) how well integrity will be managed for a well left in a suspended state.

4.1.2. Well status

A well shall be considered to be active unless it has been shut-in or suspended in accordance with the program of well activities required by section 4.1.1.

4.1.3. Well trajectory

The planned well activities and the well trajectory shall be designed to minimise the collision risk with other wells.

The WOMP shall describe how the trajectory of wells will be planned and managed to minimise the collision risk with other wells for subject wells.

4.2. Analysis of load cases

Static and dynamic load cases shall be established for a well. These load cases shall be used to determine acceptance criteria for well barriers and WBE.

4.2.1. Analysis method

The method used for load case analyses shall be appropriate to the loads and operating environment for the well.

The WOMP shall demonstrate how the load cases have been analysed for subject wells.

4.2.2. Load cases

The analysis of load cases shall cover all events and activities that could occur during the lifecycle of a well and take into account, as a minimum:

a) all well activities,

b) well trajectory,

c) temperature scenarios,

d) static loads,

e) fatigue loads resulting from load cycling,

f) dynamic loads,

g) formation induced loads, and

h) kicks.

The WOMP shall describe the load cases expected throughout the lifecycle of subject wells and demonstrate how they have been determined.

4.2.3. Safety factors

Safety factors shall be established for:

a) burst loads,

b) collapse loads,

c) axial loads,

d) tri-axial loads,

e) maximum operating pressure, and

f) maximum operating temperature.

The WOMP shall describe safety factors, demonstrate how they have been selected and how they will be applied.

4.2.4. Well design envelope

The well design envelope shall be established for each well setting out maximum and minimum operating conditions for all well lifecycle stages.

The WOMP shall include the well design envelope and demonstrate how it has been established for subject wells.

4.2.5. Kick tolerance

Estimates of the minimum kick tolerance requirements shall be established for each section of a well before that section is drilled.

The WOMP shall include the estimated kick tolerances employed for the design of each section of a subject well and describe how they were determined.

4.3. Well barrier philosophy

A well barrier philosophy shall be established for all subject wells. The well barrier philosophy shall include:

a) The interest holder's approach to the selection of barriers and barrier elements,
b) Flow zones that require isolation,
c) In-situ formations that act as barriers (as described in section 3.4),
d) Any flow zones that will be grouped together and how the risk of crossflow has been assessed,
e) Petroleum pools that will be produced,
f) How the minimum barrier requirements in section 4.4 will be met,
g) Casing setting depths,
h) Well barriers during construction,
i) Well control during drilling,
j) Well barriers during operation,
k) Well control during interventions,
l) Well barriers for shut-in wells,
m) Well barriers for suspended wells,
n) Well barriers for decommissioning, and
o) Well barrier verification, monitoring and maintenance approach.

The WOMP shall describe the well barrier philosophy for subject wells.

4.4. Number of well barriers

4.4.1. General requirement for two independent barriers

Well activities shall be designed so that the failure of a single well barrier will not result in uncontrolled flow of formation fluids into or out of a well. Wells shall have two defined and independently verified well barriers against uncontrolled flow. The two barriers may consist of one active barrier and one potential barrier. Where two independently verified well barriers are not practicable, a single barrier may be used where it can be demonstrated that the level of risk to well integrity is ALARP and acceptable.

4.4.2. Minimum number of well barriers

Wells shall be designed and constructed so that the number of well barriers in a well meet the requirements in Table 1 and Table 2. Any scenario not covered by Table 1 or Table 2 shall have well barriers that meet the requirements specified in section 4.4.1.

Table 1: Well barrier requirements during drilling of conductor or surface casing with normal pressures

Scenario	Minimum number of well barriers
No flow zones intersected	None
Between a single aquifer with normal pressures and the surface	None
Between a single aquifer with overpressures and the surface	Assessed based on flow potential
Between other flow zone (such as shallow gas, low quality water) and the surface	Assessed based on flow potential
Between two discrete flow zones	Assessed based on flow potential

Table 2: Well barrier requirements after surface casing is set

Scenario	Number of barriers
Between distinct aquifers	One
Between an aquifer and the surface	One
Between any flow zone other than an aquifer and the surface	Two
Between an aquifer and any other type of flow zone	Two
Between discrete flow zones that are not aquifers	Assessed based on risk of crossflow
Between discrete petroleum pools in a well with production from more than one petroleum pool	Production from discrete petroleum pools shall be isolated

4.4.3. Aquifer isolation

Wells shall be constructed to:

a) prevent flow to or from aquifers via the well, and

b) prevent degradation of WBEs that could be exposed to aquifers throughout the well's lifecycle.

The WOMP shall demonstrate how these aquifer isolation requirements will be met for subject wells.

4.4.3.1. Surface casing (or deep-set conductor) and cement lifecycle

The surface casing (or deep-set conductor) and cement shall be considered an active barrier throughout the well's lifecycle so that:

a) aquifers isolated from the surface or each other remain isolated,

b) protection of other WBEs is maintained, and

c) their use as WBEs for decommissioning is not compromised.

4.4.3.2. Multiple aquifers

Where a well intersects multiple aquifers, they shall be isolated from each other in accordance with Table 2. An Annular WBE separating aquifers may be considered the well barrier for this purpose.

4.4.3.3. Surface casing (or deep-set conductor) and annular cement

Wells shall be constructed so that:

a) the surface casing (or deep-set conductor) is set in a competent in-situ formation below aquifers or in a competent in-situ formation between aquifers, and

b) the surface casing (or deep-set conductor) is cemented from the casing shoe to the surface.

4.4.3.4. Surface casing (or deep-set conductor) and cement alternate approach

Where cementing of the surface casing (or deep-set conductor) from casing shoe to surface is impractical due to geological conditions, the WOMP shall demonstrate:

a) The nature of those conditions that make cementing of the surface casing impractical, and

b) How the alternate approach selected:

    a. achieves the barrier requirements in Table 2 and section 4.4.2,

    b. ensures that the surface casing will not be degraded due to exposure to formation fluids, and

    c. allows for effective decommissioning of the well.

4.4.4. Isolation of production from multiple petroleum pools in a single well

Petroleum shall not be recovered simultaneously from more than one petroleum pool in a single well unless the petroleum pools are isolated from each other. Isolation of production from more than one petroleum pool in a single well:

a) may be achieved by using a separate completion for each petroleum pool that is being produced in a single well,

b) shall be maintained after installing, replacing, modifying, removing or re-verifying a component of a well completion or WBE, and

c) shall be verified and if necessary re-established upon the acquisition of evidence that the means of isolation, or a component in the means of isolation, has been degraded.

The WOMP shall demonstrate how simultaneously production from more than one petroleum pool in a single well will be isolated from each other and how that isolation will be maintained for subject wells.

4.5. Defining well operating limits

The planned well operating limits shall be defined in the design phase. The operating limits shall comprise the minimum combination of parameters, and their maximum and minimum values within which the well may be operated to ensure that all well component specifications, with safety factors applied, are not exceeded.

The WOMP shall include the well operating limits (designed operating envelope) for all well lifecycle stages of subject wells.

4.6. Defining well barriers

A separate well barrier schematic shall be prepared that define the well barrier and all WBEs identified for a well:

a) for activities in the program of well activities (section 4.1.1),
b) when the well barrier changes,
c) when a component will be added or removed from the well barrier,
d) when the well is producing,
e) when the well is in a shut-in condition,
f) when the well is in a suspended condition, and
g) for the well in each phase of decommissioning.

Well barrier schematics should be provided in a style consistent with those shown in ISO 16530, NORSOK D-010 and 117 – Offshore Norge.

The WOMP shall include these well barrier schematics applicable to subject wells.

4.7. Well barrier element details

The WOMP shall include Well Barrier Element Acceptance Criteria (WBEAC) for all WBEs used in subject wells, along with a WBEAC table for each individual WBE identified in the well barrier schematics (section 4.6).

The WBEAC table shall include the following features as a minimum, to describe the relevant performance standard and acceptance criteria:

a) description,
b) function,
c) design, construction and selection,
d) initial test and verification,
e) use,
f) monitoring and surveillance,
g) maintenance,
h) failure modes,
i) contingencies, and
j) common WBE (if the WBE is common to two well barriers).

Listed performance standards and acceptance criteria shall make reference to any applicable technical standards.

5. Well construction, operation and intervention

5.1. Well sites

5.1.1. Well site identification

Well sites shall be identified in a permanent manner with the well name, well number and details of the interest holder.

5.1.2. Emergency contact details

Emergency contact details for active well operations shall be displayed in writing at all approaches to the well site.

5.1.3. Wellhead protection

The wellhead of a shut-in or suspended well shall have appropriate measures implemented to:

a) protect from collisions,

b) prevent operation or interference by unauthorised persons, and

c) protect the wellhead from corrosion.

5.2. Well integrity verification, monitoring, surveillance and maintenance

The interest holder shall have a well integrity verification, monitoring, surveillance and maintenance program for each well.

The WOMP shall include a description of the well integrity verification, monitoring, surveillance and maintenance program for subject wells.

5.2.1. Well integrity verification

The well integrity verification, monitoring, surveillance and maintenance program shall include:

a) the anticipated program of well activities (section 4.1.1), listed in chronological order, that identifies when:

    a. a WBE will be installed,

    b. the initial verification of a WBE will occur,

    c. a WBE will enter service,

    d. ongoing verification of a WBE will be done, and

    e. any planned re-verification of a WBE will occur.

b) initial verification of WBE after installation and before entering service,

c) methods for verifying the integrity of well barriers,

d) frequency for verifying the integrity of well barriers,

e) function testing of WBE that need to be functioned,

f) re-verification requirements for well barriers and WBE where well operating limits have been exceeded,

g) re-verification requirements for well barriers and WBE that are returning to service, and

h) re-verification requirements where there has been a substantive change to well activities, well barriers, WBE or the well operating envelope, and the relationship between well barrier verification and the WBEAC for individual WBE.

5.2.1.1. Pressure and inflow testing

The well integrity verification, monitoring, surveillance and maintenance program shall include a description of pressure and inflow testing procedures and acceptance criteria, demonstrating that they are appropriate for the well barrier or WBE being tested.

5.2.1.2. Suspended well verification

The well integrity verification, monitoring, surveillance and maintenance program shall include a program for re-verification of the integrity of suspended wells. The integrity of well barriers in suspended wells shall be re-verified at least once every 24 months.

5.2.2. Well integrity monitoring and surveillance

The well integrity verification, monitoring, surveillance and maintenance program shall define the monitoring requirements, and where applicable the surveillance requirements, to ensure that WBE continue to meet WBEAC and that wells are maintained within their operating limits.

The well integrity verification, monitoring, surveillance and maintenance program shall include:

a) monitoring and surveillance requirements for all well activities, demonstrating that they are appropriate for the well barrier or WBE being monitored and the activities being conducted in the well,

b) identification of well integrity parameters that will be monitored and associated acceptance criteria,

c) schedule for well integrity monitoring and surveillance,

d) frequency of well integrity monitoring and surveillance,

e) methods for well integrity monitoring and surveillance,

f) monitoring for wear, erosion and/or corrosion of WBE,

g) relationship between well barrier monitoring and surveillance and the WBEAC for individual WBE, and

h) response plans where monitored well integrity parameters do not meet acceptance criteria.

5.2.2.1. Pressurised WBE monitoring

All pressurised WBE shall be monitored.

5.2.2.2. Annular pressure monitoring

Annular pressures shall be monitored. An annular pressure monitoring program shown to be in accordance with API Recommended Practice 90-2 can be used to demonstrate compliance with the annular pressure monitoring requirement.

5.2.2.3. Shut-in well monitoring

The well integrity verification, monitoring and surveillance, and maintenance program shall include a program for shut-in wells. The minimum well integrity parameters that shall be monitored are:

a) At least once every month:
   a. well head pressure,
   b. annular pressures, and
b) At least once every six months:
   a. hydrocarbon gas leak.

5.2.2.4. Suspended well monitoring

The well integrity verification, monitoring, surveillance and maintenance program shall include a program for suspended wells. The minimum well integrity parameters that shall be monitored are:

a) At least once every six months:
   a. well head pressure,
   b. annular pressures, and
   c. hydrocarbon gas leaks.

5.2.3. Well integrity maintenance

The well integrity verification, monitoring, surveillance and maintenance program shall:

a) identify well barriers and WBE that require maintenance,
b) the method and frequency of maintenance, and
c) relationship between well barrier maintenance and WBEAC for individual WBE.

5.2.4. Leak monitoring and management

Interest holders shall ensure the well integrity verification, monitoring and surveillance, and maintenance program includes the systematic monitoring and management of leaks from wells and well equipment into the environment.

The requirements of this section shall be incorporated into the WOMP for subject wells.

5.2.4.1. Leak detection

Leak detection activities conducted as part of the well integrity verification, monitoring, surveillance and maintenance program (section 5.2) shall require that:

a) all persons undertaking leak detection be properly trained and competency-assured, and
b) all gas leak surveys be conducted using gas detection instruments that are:
   a. calibrated, maintained and tested in accordance with manufacturer's instructions,
   b. capable of testing to a low reading of at least 10 PPM or equivalent, and
   c. suitable for the type of gas being produced.

5.2.4.2. Leak classifications and remediation

The following leak classifications shall determine reporting and remediation requirements for leaks from wells and well equipment.

5.2.4.2.1. Class 1 leaks

A Class 1 leak constitutes an existing or probable hazard to persons, infrastructure or the environment that includes but is not limited to:

a) any leak which, in the judgment of operating personnel at the scene, is regarded as an immediate hazard,

b) a leak that has ignited, or

c) a leak due to an unplanned release from a well or well equipment that, gives a sustained Lower Explosive Limit (LEL) reading greater than 10% (5000 ppm by volume) of the LEL within 150 mm of the source of the leak.

In the event that a Class 1 leak is detected:

a) the leak shall be made safe as soon as practicable after detection,

b) repaired in accordance with the WOMP within 72 hours of identification,

c) reported as a serious incident to the Minister in accordance with regulation 66K of the Regulations,

d) if the leak cannot be repaired within 72 hours of detection, the reason for the delay and a target date for completion of the work shall be submitted to the Minister, and

e) the rate and volume of the leak shall be determined if reasonably practicable to do so.

5.2.4.2.2. Class 2 leaks

A Class 2 leak constitutes little to no immediate hazard at the time of classification but has the potential to deteriorate. A Class 2 leak includes but is not limited to, a leak due to an unplanned release from a well or well equipment that, gives a sustained reading greater than 500 ppm (but less than 5000 ppm) by volume within 150 mm of the source of the leak.

In the event that a Class 2 leak is detected:

a) the leak shall be made safe as soon as practicable after detection,

b) reported as a reportable incident to the Minister in accordance with regulation 66L of the Regulations,

c) repaired in accordance with the WOMP within 30 days of identification,

d) if the leak cannot be repaired within 30 days of detection, the reason for the delay and a target date for completion of the work shall be submitted to the Minister, and

e) the rate and volume of the leak shall be determined if reasonably practicable to do so.

5.2.4.2.3. Class 3 leaks

A Class 3 leak is a leak that is non-hazardous at the time of classification and can reasonably be expected to remain non-hazardous.

In the event that a Class 3 leak is detected:

a) the leak shall be repaired in accordance with the WOMP as soon as reasonably practicable, and

b) the details of Class 3 leaks shall be recorded and reported in accordance with the WOMP.

5.3. Operating with compromised well barrier element

Where a well barrier or WBE is compromised and that condition is not covered by the WOMP, well activities shall only be conducted in accordance with the Well Control Manual for the well or an exemption has been obtained under regulation 66AAE of the Regulations.

5.4. Flow zones intercepted during drilling

Drilling activities shall be conducted so that flow zones that have the potential to impact well integrity can be identified during drilling operations.

The WOMP shall demonstrate how drilling activities will be conducted to identify flow zones encountered during drilling and how their impact on well integrity will be assessed and managed.

5.5. Well construction operations

5.5.1. Well control equipment

5.5.1.1. Installation of well control equipment

During well construction, a well barrier that includes well control equipment (such as a blowout preventer stack and wellhead) shall be established for all operations prior to drilling below the surface casing string.

This well barrier shall be defined in the WOMP as per section 4.6. Well control equipment shall meet the requirements of section 6.5.

5.5.1.2. Shallow gas hazard

Drilling activities shall be conducted so that shallow gas hazards are managed during drilling operations. For wells with limited offset well data, or for wells drilled in those areas having known shallow gas accumulations, wells shall have:

a) a system to safely divert petroleum and other fluids,

b) a means to flare gas, and

c) sufficient kill fluid to regain control of the well in the event of pressurised fluids occurring below the shoe of the conductor string.

The WOMP shall demonstrate how the interest holder will manage shallow gas hazards during drilling of subject wells.

5.5.1.3. Blowout preventer removal

The blowout preventer shall not be removed unless all flow zones below the surface casing shoe have been isolated from the surface by two independent, verified well barriers.

5.5.1.4. Well control equipment removal

Well control equipment shall not be removed unless all flow zones below the surface casing shoe have been isolated from the surface by two independent, verified well barriers.

5.5.2. Pore pressure and fracture gradient monitoring

The pore pressure and fracture gradient shall be monitored during drilling operations. The level of monitoring shall be determined according to the well's complexity and risks to well integrity.

The WOMP shall include a description of the pore pressure and fracture gradient monitoring approach including:

a) the basis for the level of monitoring for each well section and trigger levels,

b) the methods used for pore pressure and fracture gradient monitoring,

c) the frequency of pore pressure and fracture gradient monitoring, and

d) response plans where pore pressure and fracture gradient monitoring reaches trigger levels.

5.5.3. Kick tolerance

The kick tolerance of the formation being drilled shall be known at all times. This may be demonstrated through a Formation Integrity Test or data from offset wells.

The WOMP shall demonstrate how the kick tolerances for each section of a subject well will be determined.

5.5.4. Gas detection during drilling

A monitoring system shall be in place to identify:

a) petroleum bearing zones and potential gas influx, and

b) other gases that have the potential to impact well integrity

prior to drilling below the surface casing string.

The WOMP shall describe the monitoring system and basis for its selection for subject wells.

5.5.4.1. Shallow gas hazard

For wells with limited offset well data, or for wells drilled in those areas having known shallow gas accumulations, the monitoring system shall be installed to detect petroleum prior to drilling below the shoe of the conductor string.

5.5.5. Surface gas handling system

Wells shall have a surface gas handling system installed when drilling formation where gas is anticipated, or during well interventions where gas to surface is anticipated. The gas handling system shall be:

a) designed to be fit for purpose with a system capacity that is appropriate for anticipated gas volumes and the properties of the drilling fluid,

b) compatible with the well's well control equipment and operations,

c) compatible with the well's pore pressure and fracture gradient monitoring approach,

d) compatible with the drilling fluid handling system, and

e) operated within its operating limits.

The WOMP shall describe the surface gas handling system, basis for its selection and operating procedures for subject wells.

5.5.6. Well trajectory

The position and trajectory of a well being drilled shall be known to a sufficient level of accuracy to allow:

a) mitigation of the risk of collision with other wells,

b) reduction in well location uncertainty in case a relief well becomes necessary,

c) confirmation that the trajectory is compatible with the well design, and

d) record keeping for future activities.

The WOMP shall describe how the well trajectory survey requirements have been determined and how the survey methods for the position and trajectory of subject wells meet these requirements.

5.6. Well evaluation

5.6.1. Downhole logging contingency

The interest holder shall have a contingency plan in the event of logging equipment being lost down hole.

The WOMP shall describe this contingency plan for subject wells.

5.6.1.1. Well logging with radioactive sources

In the event that a radiation source as defined by the *Radiation Protection Act 2004* is lost in a well, the interest holder is required to make best attempts to retrieve it. If the radiation source cannot be retrieved, the WOMP shall be reviewed to take into account the interest holder's plans to manage the lost radiation source.

5.6.2. Well production testing

Well production testing activities shall be deemed to be in accordance with a WOMP for that well only if:

a) a well barrier schematic for the well configurations used during the production test is included in the WOMP,

b) all load cases and operating conditions that WBE and well components could be exposed to during production tests have been determined and are within the well operating limits for WBE and well components covered by the WOMP,

c) the integrity of all WBE and well components will be verified according to the WOMP,

d) the well integrity verification, monitoring, surveillance and maintenance program (section 5.2) defined in the WOMP will be applied, and

e) potential well control incidents during production testing are included in the WOMP or well control manual.

5.6.2.1. Well production testing monitoring

Wellhead pressures, fluid rates, fluid volumes and fluid compositions shall be monitored during well production testing.

5.6.2.2. Pressure testing prior to production testing

Pressure testing shall be completed prior to production testing.

For production testing:

a) in a cased hole a pressure test that exceeds the maximum anticipated pressures shall be completed to demonstrate mechanical integrity and define a maximum allowable operating pressure (MAOP), and

b) in an open hole a pressure test to the MAOP of the pressure-exposed elements of the system.

5.6.2.3. Pressure testing prior to diagnostic fracture injectivity testing

Pressure testing shall be completed immediately prior to diagnostic fracture injectivity testing.

For diagnostic fracture injectivity testing:

a) in a cased hole a pressure test that exceeds the maximum anticipated pressures shall be completed to demonstrate mechanical integrity and define a MAOP, and

b) in an open hole a pressure test to the MAOP of the pressure-exposed elements of the system.

6. Well barrier element specific requirements

6.1. General

The requirements in section 6 apply to specific types of WBEs. They do not replace the need for an interest holder to properly evaluate all aspects of the WBEs and their design and to document them in the WOMP as per section 4.7.

6.2. Casing and tubing

6.2.1. Casing and tubing design

Casing and tubing shall be designed to withstand all loads anticipated during the well lifecycle and activities or well conditions that could degrade their performance, including but not limited to:

a) loads and stresses determined under section 4.2,

b) temperature scenarios,

c) corrosive conditions,

d) all well activities,

e) well trajectory, and

f) well life cycle casing wear and/or erosion.

The WOMP shall demonstrate how the casing and tubing performance requirements have been determined for subject wells.

6.2.1.1. Liner lap minimum length

Where a liner is used, the minimum liner lap length shall be 100 m when it is part of a WBE.

6.2.2. Casing and tubing selection

Casing and tubing shall be selected to meet the performance requirements determined under section 6.2.1, including:

a) design safety factors,

b) de-rating due to temperature,

c) well lifecycle corrosion, wear and erosion, and

d) any other cause of degradation.

The WOMP shall demonstrate how the casing and tubing selected for subject wells meet the performance requirements determined under section 6.2.1.

6.2.2.1. Casing and tubing standards

All casing and tubing shall be manufactured to the latest edition of API 5CT.

The rated capacity of the pipe body and connections may be obtained from the latest edition of API 5CT or the manufacturer's technical specifications.

6.2.2.2. Gas-tight connections

Gas-tight connection shall be used for the casing and tubing strings that function as WBE in primary and secondary barriers to petroleum flow.

The WOMP shall demonstrate that the casing and tubing strings that function as WBE in primary and secondary barriers to petroleum flow complies with the requirements for gas-tight connections for subject wells.

6.2.2.2.1. Gas-tight connection standard

Connections certified in accordance with either ISO 13679 Procedures For Testing Casing And Tubing Connections or API RP 5C5 Procedures for Testing Casing and Tubing Connections may be used to demonstrate compliance with section 6.2.2.2. The Connection Assessment Level shall be appropriate for the casing and tubing performance requirements determined under section 6.2.1.

6.2.2.2.2. Gas-tight connection exception

Section 6.2.2.2 does not apply to:

a) casing and tubing used for temporary intervention activities,

b) casing strings that are a WBE in a secondary barrier during temporary activities, and

c) wells that will be decommissioned within 12 months of completion.

The WOMP shall describe the temporary intervention activities to which this exception will be applied to subject wells.

6.2.3. Casing and tubing corrosion control

Casing shall be designed and installed to prevent corrosion from impacting on the casing's performance as a WBE.

The WOMP shall describe how the impacts of corrosion on casing that could impact on well integrity will be prevented for subject wells.

6.2.4. Casing and tubing verification

6.2.4.1. Initial test and verification

Casing and tubing shall be verified by pressure testing prior to:

a) drilling out for the next hole section in the case of the surface casing or intermediate casing,

b) prior to stimulation, diagnostic fracture injection test, or completion operations commencing in the case of production casing, and

c) prior to the introduction of hydrocarbons for production casing or production tubing.

The WOMP shall describe the pressure testing program for casing and tubing for subject wells.

6.2.4.2. Casing and tubing pressure test requirements

Pressure testing of casing and tubing shall be conducted so that:

a) pressures are greater than the maximum anticipated surface pressure if the well is voided to reservoir fluid, allowing for possible leak off at the previous casing shoe,

b) pressure limits for future well activities are confirmed,

c) pressures are equal to the maximum annulus pressure utilised for pressure testing of completion strings/tools for the particular string,

d) pressures will not exceed the casing or tubing's MAOP,

e) pressures will not exceed the rated capacity of the weakest component of the casing string,

f) that other WBE, including cement, are not compromised by the pressure test.

6.2.5. Surface protection

Wells and well components shall be protected against surface formation instability and constructed to enable the circulation of drilling fluid from the well before the surface casing is installed. A conductor casing string may be used.

The WOMP shall describe how surface formation instability will be managed and circulation of drilling fluid achieved before installation of the surface casing for subject wells.

6.2.6. Casing and tubing monitoring

6.2.6.1. Casing and tubing wear, erosion and/or corrosion monitoring

Acceptance criteria and a monitoring program for casing and tubing monitoring for wear, erosion and/or corrosion shall be established for wells.

The WOMP shall describe the acceptance criteria and monitoring program for casing and tubing monitoring for wear, erosion and/or corrosion and how they have been established for subject wells.

6.3. Annular cement

Annular (or primary) cement means the cement in a solid state located in the annulus between concentric casing strings or between casing and the formation.

6.3.1. Annular cement design

Annular cement shall be designed to withstand all loads anticipated during the well lifecycle and activities or well conditions that could degrade their performance and placement of the cement, including but not limited to:

a) loads and stresses determined under section 4.2,

b) loads imposed by pressure testing of other WBE,

c) the wellbore environment, including:

    a. pressures,

    b. temperatures,

    c. formation fluid properties,

    d. drilling fluid properties,

    e. formation integrity,

    f. flow zones.

d) zonal isolation requirements,

e) all well activities throughout the well's lifecycle, including decommissioning,

f) well trajectory, and

g) well volume.

The WOMP shall demonstrate how the annular cement performance requirements have been determined for subject wells.

6.3.1.1. Cement slurry properties

Annular cement slurry properties and placement operations shall be designed so that:

a) where the cement slurry is acting as a WBE, the cement slurry meets acceptance criteria for this WBE, and

b) performance of the annular cement is not impacted by its placement.

6.3.1.2. Zonal isolation

Annular cement and annular cementing operations shall be designed to:

a) prevent and/or control flows just prior to, during, and after primary cementing operations to install or "set" casing and liner pipe strings in wells, and

b) prevent pressure communication along the annulus throughout the well's lifecycle.

6.3.2. Annular cement selection

Annular cement shall be selected to meet the performance requirements determined under section 6.3.1.

The WOMP shall demonstrate how the annular cement for subject wells meets the performance requirements determined under section 6.3.1.

6.3.3. Annular cement composition testing

The cement recipe shall be laboratory tested using representative samples of the mix water, cement and additives to confirm the resulting slurry used for annular cementing meets the performance requirements of the well design determined under section 6.3.1.

The WOMP shall demonstrate how laboratory testing will confirm the cement design meets the performance requirements determined under section 6.3.1 for subject wells.

6.3.3.1. Cement testing standard

Laboratory testing adhering to ISO 10426-2 Cements and materials for well cementing — Part 2: Testing of well cements / API RP 10B-2 – Recommended Practice for Testing Well Cements may be used to demonstrate compliance where the performance requirements are within the scope of this standard.

6.3.4. Planned annular cement length

The planned annulus cement length shall be designed to allow for all well activities, including side tracking and decommissioning.

The WOMP shall demonstrate how the planned annular cement lengths for subject wells have been determined.

6.3.4.1. Minimum requirements

The annular cement lengths shall meet the minimum criteria in Table 3.

Table 3: Annular cement length requirements

Casing interval/ scenario	Bottom of cement	Top of cement
Conductor	To meet structural integrity requirements (section 6.2.5).	
Deep-set conductor	As per section 4.4.3.3 and section 4.4.3.4.	
Surface casing	As per section 4.4.3.3 and section 4.4.3.4.	
Intermediate casing(s)	Intermediate casing shoe.	A minimum of 200 m measured depth (MD) above the casing shoe of the previous casing string.
Production casing	Production casing shoe.	A minimum of 200 m MD above the casing shoe of the previous casing string.
Production liner	Liner shoe.	Annulus cement length shall be minimum 100 m MD above the casing shoe.
Production casing or liner with uncemented annulus	• No more than 30 m true vertical depth (TVD) above the predicted depth of the shallowest high potential flow zone targeted for production, and • Adjacent to the in-situ formation acting as part of the primary well barrier to the shallowest high potential flow zone targeted for production, and • A minimum of 100 m MD below the casing shoe of the previous casing string.	• Production casing: A minimum of 200 m MD above the casing shoe of the previous casing string. • Production liner: Annulus cement length shall be minimum 100 m MD above the casing shoe.

6.3.4.2. Minimum shoe track length

The minimum shoe track length shall be:

a) One casing joint for the surface casing, and

b) Two casing joints for casing set below the surface casing.

6.3.5. Casing centralisation

Casing centralisation shall be designed to achieve a minimum of 70% standoff across the entire cementing interval.

The WOMP shall demonstrate:

a) that the centralisers selected suit the application,

b) that the casing centralisation plan has been simulated, including
    a. the well trajectory considered,
    b. the simulation method, and
    c. the results of simulation.

for subject wells.

6.3.5.1. Casing centralisation standard

Casing centralisation design adhering to API 10D-2 – Recommended Practice for Centralizer Placement and Stop Collar Testing may be used to demonstrate compliance.

6.3.5.2. Deviated wells

Section 6.3.5 does not apply to the deepest part of a casing string or liner when:

a) the well deviation is equal to or greater than 60 degrees from vertical, and
b) the section is within a single flow zone.

6.3.6. Annular cement initial verification

6.3.6.1. Annular cement placement verification

Annular cement placement shall be monitored to confirm that:

a) the cement slurry has been mixed in accordance with design,
b) hole cleaning has been conducted in accordance with design,
c) cementing operations have been conducted in accordance with design,
d) any returns of mud and/or cement to surface are in accordance with design,
e) placement pressures are in accordance with design, and
f) shoe track volume is in accordance with design.

The WOMP shall describe the acceptance criteria for each casing section for annular cement placement verification for subject wells.

6.3.6.2. Annular cement initial strength verification

The strength of annular cement shall be verified prior to drilling out the casing shoe track for the subsequent hole section.

The WOMP shall demonstrate how the required strength of the cement has been determined and how it will be verified prior to drilling out the casing shoe for all sections of subject wells.

6.3.6.3. Blowout preventer removal wait on cement

Where annular cement is a WBE in a well barrier to meet the requirements of section 5.5.1.3, the WBEAC shall include verification that the annular cement has achieved sufficient strength.

The WOMP shall demonstrate how the required strength of the cement has been determined and how it will be verified prior to removal of the blowout preventer for subject wells.

6.3.6.4. Annular cement sealing ability verification

The cement sealing ability shall be verified through a formation integrity test after drilling out the casing shoe/window.

The WOMP shall describe the acceptance criteria for each casing section for a formation integrity test for subject wells.

6.3.6.5. Annular cement length verification

The cement length may be verified through:

a) cement evaluation logs, and/or

b) displacement calculations.

The WOMP shall describe how the annular cement length verification method has been selected and the acceptance criteria for subject wells.

6.3.6.6. Petroleum bearing zone annular cement bond verification

When a petroleum bearing zone is intersected during drilling and subsequently cemented, a cement evaluation log shall be performed as a verification of annular cement bond with the formation and casing.

The WOMP shall describe the cement evaluation log method, how it has been selected and the acceptance criteria for subject wells.

6.3.6.7. Hydraulic fracturing operations annular cement bond verification

When well activities include hydraulic fracture operations and/or diagnostic fracture integrity testing, a cement evaluation log shall be performed as a verification of good annular cement for 150 m TVD above the base of the in-situ formation acting as part of the primary well barrier above the zone to be hydraulically fractured. The length of annular cement may be made up of discrete zones with a combined length of 150 m.

The WOMP shall describe the cement evaluation log method, how it has been selected and the acceptance criteria for subject wells.

6.3.7. Cement contingency

The WOMP shall detail a process that outlines the steps to be taken in the event the primary cement job fails to meet its objectives and remediation is required to meet those objectives.

6.4. Wellhead and trees

Wells shall have WBEAC for each configuration of:

a) Wellheads,

b) Trees

and their components used throughout a well’s lifecycle.

The WOMP shall describe the WBEAC for wellheads, trees and their components used for subject wells.

6.4.1. Wellhead and tree design

Wellheads and trees shall be designed to withstand all loads anticipated during the well lifecycle and activities or well conditions that could degrade their performance, including but not limited to:

a) loads and stresses determined under section 4.2,

b) temperature scenarios,

c) fluid properties,

d) corrosive conditions,

e) all well activities, and

f) well lifecycle casing wear and/or erosion.

The WOMP shall demonstrate how the wellhead and tree performance requirements have been determined for subject wells.

6.4.1.1. Wellhead and tree standards

Wellhead and tree equipment shall be specified in accordance with API Spec 6A and ISO 10423.

6.4.1.2. Wellhead and tree components

All wellhead or tree components (including valves, access ports, chokes, actuators, plugs, connectors) shall be rated to the same or a higher pressure as the section of the wellhead or tree they are attached to.

6.4.1.3. Wellhead and tree access to annuli

Wellheads and trees shall be designed to allow for access to annuli for sealing, testing, monitoring, injecting into, and bleeding off between annuli. See section 5.2.2.2.

6.4.1.4. Casing and tubing movement

Wellheads shall be designed to account for casing and tubing movement and the implications for well integrity due to anticipated loads throughout the well lifecycle.

6.4.2. Wellhead and tree selection

Wellheads and trees shall be selected to meet the performance requirements determined under section 6.4.1, including:

a) Pressure class,

b) Temperature class,

c) Material class,

d) Product specification level, and

e) Performance requirement.

The WOMP shall demonstrate how the wellhead and trees selected for subject wells meet the performance requirements determined under section 6.4.1.

6.4.3. Wellhead and tree equipment initial verification

Wellhead and tree equipment shall be tested to the design pressure for the specific hole section or activity. All components of wellheads and trees that are designed to require site verification whether individually or collectively shall be:

a) verified to conform to performance requirements determined under section 6.4.1 prior to installation,

b) function test potential barriers prior to installation, and

c) pressure tested immediately after installation. This pressure testing may be conducted as part of the wellhead or tree assembly.

The WOMP shall describe the initial verification process for wellhead and tree equipment for subject wells.

6.4.3.1. Maximum testing pressures

Pressure testing of annuli shall not exceed 80% of the collapse rating of the inner casing string of the annuli.

6.4.4. Wellhead and tree equipment testing and monitoring

Wellhead and tree equipment shall be monitored, tested and inspected frequently.

The WOMP shall describe the monitoring, testing and inspection program including:

a) the type of monitoring, testing and inspection,

b) frequency of monitoring, testing and inspection,

c) the rationale for the monitoring, testing and inspection regime, and

d) monitoring, testing and inspection acceptance criteria

for subject wells.

6.5. Well control equipment

6.5.1. Well control equipment design

The interest holder shall ensure that well control equipment is provided for use during well operations when required by section 5.5.1 and its sub-sections. The level of well control equipment required on any operation, and the configuration employed, shall be suitable for the well.

The WOMP shall demonstrate how the performance requirements of well control equipment have been determined for subject wells.

6.5.1.1. Well control equipment standards

Well control equipment shall be designed to a relevant standard, where available.

6.5.1.1.1. API STD 53

Well control equipment that is within the scope of API Standard 53 Well Control Equipment Systems for Drilling Wells shall comply with that standard.

6.5.1.1.2. API SPEC 16A

Well control equipment that is within the scope of API Specification 16A Specification for Drill-through Equipment shall comply with that specification.

6.5.1.1.3. API SPEC 16C

Well control equipment that is within the scope of API Specification 16C Specification for Choke and Kill Systems shall comply with that specification.

6.5.1.1.4. API SPEC 16D

Well control equipment that is within the scope of API Specification 16D Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment shall comply with that specification.

6.5.1.2. Temperature rating of well control equipment

The working temperature rating for well control equipment shall meet the maximum anticipated continuous exposure temperature for rubber/elastomer components.

6.5.1.3. Pressure rating of well control equipment

All well control equipment shall be rated to exceed maximum anticipated shut-in surface pressure.

6.5.2. Well control equipment selection

Well control equipment shall be selected to meet the performance requirements determined under section 6.5.1.

The WOMP shall demonstrate how the well control equipment selected for subject wells meet the performance requirements determined under section 6.5.1.

6.5.3. Well control equipment initial verification

Well control equipment shall be verified via:

a) function testing after installation,

b) pressure testing, and

c) well control system testing

before being placed into service.

The WOMP shall describe the initial verification process for well control equipment for subject wells.

6.5.3.1. Well control equipment initial test standard

Initial tests on well control equipment shall be conducted in accordance with API Standard 53 Well Control Equipment Systems for Drilling Wells where applicable.

6.5.4. Well control equipment monitoring, testing and maintenance

The interest holder shall ensure that there is a well control equipment monitoring, testing and maintenance program for all wells that is in accordance with API Standard 53 Well Control Equipment Systems for Drilling Wells.

The WOMP shall describe the minimum requirements for the well control equipment monitoring, testing and maintenance program for subject wells.

6.5.4.1. Function testing

Function testing shall be performed on well control equipment that have been:

a) exposed to abnormal loads, or

b) after repairs.

6.6. Fluid column

6.6.1. Fluid column design

6.6.1.1. Fluid column performance requirements

The fluid column's performance requirements shall be determined to meet well objective and withstand conditions anticipated during the well lifecycle and activities or well conditions that could degrade its performance, including but not limited to:

a) whether the fluid column is an active barrier (overbalanced drilling) or an element of an underbalanced/managed pressure system,

b) loads and stresses determined under section 4.2,

c) anticipated geological conditions:

    a. pore pressure gradient,

    b. formation integrity and stability,

    c. inflow and outflow zones,

    d. temperature scenarios,

    e. formation fluid composition, and

    f. sour conditions.

d) oxygen control,

e) corrosion control,

f) bacterial control,

g) the well activity that the fluid is used for,

h) well trajectory,

i) effective circulation density,

j) pressure changes associated with tripping,

k) cuttings generated, and

l) formation damage susceptibility.

The WOMP shall demonstrate how the fluid column's performance requirements have been determined for subject wells.

6.6.1.2. Fluid column material compatibility

The fluid column's composition shall be compatible with the drilling rig, all WBEs and fluid handling components that have the potential to be exposed to the fluid.

The WOMP shall demonstrate that the fluid column's composition will be compatible with the drilling rig, all WBEs and fluid handling components that may be exposed to the fluid for subject well.

6.6.1.3. Fluid handling system

The fluid column handling system shall be designed so that:

a) critical properties can be established and maintained,

b) critical properties can be monitored at all times, and

c) contingency plans can be achieved.

6.6.1.3.1. Fluid handling system transfers

The fluid system design and operation shall allow for accurate volume monitoring at all times. Transfers into or out of the active mud system shall not compromise the ability to monitor fluid volumes in the active system.

6.6.1.3.2. Gas removal from fluid column

The drilling fluid handling system and surface gas handling system for drilling operations shall allow for the removal of gas from the drilling fluid.

6.6.2. Fluid column selection

The fluid column's composition shall be selected so that it will achieve the critical properties and specifications necessary to meet the performance requirements determined according to section 6.6.1. The critical fluid properties include:

a) rheological properties,

b) density, and

c) chemical properties.

The WOMP shall demonstrate how the fluid column and mud additives used for subject wells will achieve the critical fluid properties and specifications necessary to meet the performance requirements determined under section 6.6.1.

6.6.3. Fluid column initial verification

The WOMP shall describe the initial verification procedure for the fluid column. The volume of fluid and the critical fluid properties shall be verified.

6.6.4. Fluid column monitoring

A system for accurately monitoring the fluid column shall be in place during all drilling operations that:

a) identifies the parameters that will be monitored and associated acceptance criteria, including:
   a. drilling fluid volume gains and losses,
   b. drilling fluid volumes required to fill the hole on trips,
   c. density in to and out of the well,
   d. rheology (or viscosity) in to and out of the well,
   e. gas in the return fluid flow once gas bearing strata are intersected, and
   f. drilling fluid pumping pressures.
b) has a schedule for fluid column monitoring and surveillance,
c) establishes criteria for frequency of fluid column monitoring and surveillance, and
d) describes methods for fluid column monitoring and surveillance.

The WOMP shall describe this monitoring system.

6.6.4.1. Fluid column testing

Where the fluid column is used as an active barrier during well operations, the testing of the fluid shall be carried out a minimum of twice per day in accordance with:

a) API RP 13B-1 Recommended Practice for Field testing of drilling fluids Part 1: Water-based fluids, for water-based drilling fluids, and
b) API RP 13B-2, Recommended Practice for Field testing of drilling fluids — Part 2: Oil-based fluids, for oil-based drilling fluids.

The WOMP shall describe the fluid column testing procedures and the acceptance criteria for fluid column testing.

6.6.5. Fluid column contingencies

6.6.5.1. Response plans

Response plans shall be in place for the event of fluid column monitoring detects parameters that do not meet acceptance criteria.

The WOMP shall include these response plans.

6.6.5.2. Lost circulation material

Lost circulation management strategies shall be in place for all wells. The lost circulation management strategy shall include:

a) which lost circulation materials would be used,
b) how lost circulation materials would be used,
c) how lost circulation materials would be accessed (stored on site or otherwise), and
d) how the fluid’s critical properties would be maintained.

6.6.5.3. Fluid volumes

Where the fluid column is being used as the primary barrier for a well, sufficient reserves of drilling fluid and supplies of drilling fluid materials shall be available at the well site for immediate use so that fluid column volume and critical properties can be maintained.

6.6.5.4. Kill fluid

The volume and properties of fluid required to kill the well shall be known at all times. Quantities of fluid and supplies of drilling fluid materials shall be maintained on location.

6.7. Cement plugs

Cement plugs refer to cement set in the wellbore to temporarily or permanently block flow, or as an aid to alter the wells path.

6.7.1. Cement plug design

Cement plugs shall be designed to withstand all loads anticipated during the well lifecycle and activities or well conditions that could degrade their performance and placement of the cement, including but not limited to:

a) loads and stresses determined under section 4.2,

b) loads imposed by pressure testing of other WBE,

c) the wellbore environment, including:

    a. pressures,

    b. temperatures,

    c. formation fluid properties,

    d. drilling fluid properties,

    e. formation integrity, and

    f. flow zones.

d) zonal isolation requirements,

e) all well activities throughout the well's lifecycle, including decommissioning,

f) well trajectory, and

g) well volume.

The WOMP shall demonstrate how the cement plug performance requirements have been determined for subject wells.

6.7.1.1. Cement slurry properties

Cement plug slurry properties and placement operations shall be designed so that:

a) where the cement is acting as a WBE, the cement slurry properties meet acceptance criteria for this WBE, and

b) performance of the cement plug is not impacted by its placement.

6.7.1.2. Zonal isolation

Cement plugs and cement plug installation activities shall be designed to:

a) prevent and/or control flows just prior to, during, and after setting of cement plugs, and

b) prevent pressure communication along the well bore throughout the well's lifecycle.

6.7.2. Cement plug composition testing

The cement recipe shall be laboratory tested using representative samples of the mix water, cement and additives to confirm the resulting slurry used for primary cementing meets the requirements of the well design.

The WOMP shall describe any proposed laboratory testing.

6.7.2.1. Cement plug composition testing standard

Laboratory testing adhering to ISO 10426-2 Cements and materials for well cementing — Part 2: Testing of well cements / API RP 10B-2 – Recommended Practice for Testing Well Cements may be used to demonstrate compliance where the performance requirements are within the scope of this standard.

6.7.3. Cement plug initial verification

Cement plugs shall be verified upon placement.

The WOMP shall describe the acceptance criteria for initial verification of each cement plug for subject wells.

6.7.3.1. Cement plug placement verification

Cement plug placement shall be monitored to confirm that:

a) the cement slurry has been mixed in accordance with design,

b) cementing operations have been conducted in accordance with design,

c) cement placement pressures meet design pressures, and

d) the requirements of Section 7, "Post-cement Job Analysis and Evaluation", of API Standard 65-2 are met.

6.7.3.2. Cement plug position verification

The position of cement plugs shall be verified as follows:

a) off bottom open hole cement plugs shall be verified by tagging the plug with a minimum 2270 kg or 5000 lb drill string weight,

b) for consecutive stacked cement plugs with the first plug set on bottom or solid base (such as a mechanical packer, other verified cement plug) verification of the top of good quality cement shall carried out by tagging the top plug with a minimum 2270 kg or 5000 lb drill string weight. If using a sacrificial stinger to set open hole plugs, no tag is necessary where no losses are observed during cement placement,

c) for a cased hole cement plug with the bottom of the plug exposed to open hole verification shall be done by tagging the top plug with a minimum 2270 kg or 5000 lb drill string weight.

d) for a cased hole cement plug supported by a pressure tested bridge plug, or pressure tested cement plug, verification may be by post cement job report and calculations, or by tagging the plug with a minimum 2270 kg or 5000 lb drill string weight,

e) for an unsupported cased hole cement plug barrier not exposed to open hole below, verification shall be done by tagging the plug with a minimum 2270 kg or 5000 lb drill string weight, and

f) when a sacrificial string is used to place a cement plug, verification may be via a combination of:

   a. pressure testing to confirm isolation; and

   b. verification of the conduct of the cement job.

6.7.3.2.1. Shallow set cement plug position verification

Where section 6.7.3.2 is not practical for shallow set cement plugs that are at or near the surface, the interest holder may use alternate means to verify the position of the cement plug.

The WOMP shall describe the alternative means to verify the position of the cement plug for subject wells.

6.7.3.3. Cement plug sealing verification in cased hole

Cement plug sealing ability shall be verified by a pressure test, which shall:

a) be to 7 MPa or 1000 psi above the estimated (or previously recorded) leak-off pressure below casing / corresponding to the most likely leak path, or

b) 3.5 MPa or 500 psi for the surface casing plugs, or

c) 3.5 MPa or 500 psi in mature fields where offset well data provides certainty for expected leak off pressures, and

d) not exceed pressures that would compromise other WBE.

6.7.3.3.1. Cement plug sealing verification in cased hole exceptions

A pressure test is not required for a cased hole cement plug supported by a pressure tested bridge plug, or pressure tested cement plug.

7. Well control

7.1. Well control drills

Regular drills pertaining to on-going or up-coming operations shall be conducted to train involved personnel in the detection, prevention and recovery of lost barriers and other unplanned well control events.

7.2. Well integrity management

The interest holder shall have a system for monitoring the integrity of wells at all times that will allow for the early detection of inflow to or out flow from the well.

The WOMP shall demonstrate:

a) how monitoring determined under section 5.2 will allow for the early detection of inflow (a kick) to or out flow from the well,

b) what the tolerances are for inflow (a kick) to or out flow from the well to be managed using active well barriers,

c) how inflow (a kick) to or out flow from the well below these tolerance levels will be managed using active well barriers, and

d) how the WOMP interfaces with well control procedures documented in the Well Control Manual for the well where tolerances for inflow to or out flow from the well are exceeded (where a kick has been detected).

7.3. Drilling fluid requirements

The contingency requirements specified in section 6.6.5 apply when the drill fluid is not a WBE.

7.4. Secondary well control

Well barrier schematics and WBEAC shall include components that could be used during secondary well control.

8. Special conditions

For wells that are expecting to encounter special conditions, the WOMP shall demonstrate consideration of the following requirements as appropriate.

8.1. High Pressure High Temperature (HPHT) wells

8.1.1. High pressure high temperature well design

In addition to all other requirements of this code, for wells that are expected to have high pressure and/or high temperature conditions. The well design shall demonstrate:

a) how the well integrity risks associated with drilling and operating wells with high pressure and/or high temperature conditions have been addressed,

b) that the high pressure and/or high temperature conditions have been incorporated in the well load cases (section 4.2),

c) that equipment and materials selected for well construction, well completion, well operations and well control are fit for purpose,

d) how the well construction requirements will be met by the selected drilling rig,

e) how well conditions will be monitored during drilling and completion activities, if different to non-HPHT wells, and

f) that the possibility of a temperature rise causing trapped fluid, generating a pressure in excess of the equipment rating, is managed.

8.1.2. Wellheads for high temperature wells

The wellhead-casing interfaces for high temperature wells shall be designed to allow for thermal expansion.

8.2. Hydrogen sulfide (H_2S)

This Code only considers H_2S from a well integrity perspective.

8.2.1. H_2S well design

For wells that are expected to have H_2S (or sour) conditions, the well design shall demonstrate:

a) how the well integrity risks associated with drilling and operating wells with H_2S conditions have been addressed,

b) that equipment and materials selected for well construction, well completion, well operations and well control are fit for purpose,

c) how H_2S levels will be monitored during drilling and completion activities, and

d) how the effects of H_2S during well shut-in and/or suspension are managed.

8.2.2. Material selection for H_2S wells

Equipment and materials selected for use under sour conditions shall be in accordance with ANSI/NACE MR0175/ISO 15156.

8.2.2.1. Use of non-H_2S rated materials

If it is proposed to use a material which is intended for 'non H_2S service', a risk assessment shall be conducted to demonstrate the integrity of equipment or materials over the following timeframes:

a) during a single temporary exposure to sour reservoir fluids (e.g. circulating out a kick, or if there is a leak in the test string while production testing), or

b) in the time between exposure to sour reservoir fluids and completion of evacuation of the well site in the event of uncontrolled total displacement of the well contents by such fluids.

8.2.2.2. Non-metallic parts exposed to H_2S

Elastomers, packing and other non-ferrous parts exposed to H_2S shall be resistant to H_2S at the maximum anticipated temperature of exposure.

8.2.2.3. Drilling fluids and H_2S

A drilling fluid program shall include the use of a H_2S scavenger to manage H_2S levels in the drilling fluid.

8.3. Underbalanced drilling or managed pressure drilling

8.3.1. Entrained petroleum management

Underbalanced drilling or managed pressure drilling operations shall be conducted to maintain well control, handle petroleum entrained in the drilling fluid, and to avoid risks to well integrity from an explosive mixture developing in the well.

The WOMP shall demonstrate how underbalanced drilling or managed pressure drilling operations have been designed and how they will be implemented to

a) mitigate the risks to well integrity from an explosive mixture developing in a well, and

b) handle petroleum entrained in the drilling fluid

for subject wells.

8.3.2. Well barriers for underbalanced drilling or managed pressure drilling

If undertaking underbalanced drilling or managed pressure drilling activities, well barriers shall be in place to counter the absence of weighted drilling fluid as the primary well integrity management method.

8.3.2.1. Non return valves

A downhole non-return valve shall be fitted as a WBE and shall comply with API Specification 7NRV Specification for Drill String Non-return Valves.

8.3.2.2. Surface drill string valves

Full operating safety valves, kelly cocks, stab-in safety valves or an equivalent method to control a kick through the drill string shall be available during underbalanced drilling operations.

8.3.2.3. Rotary control device

Rotary Control Devices shall be installed as a WBE and shall comply with API Specification 16RCD Specification for Rotating Control Devices.

8.3.2.3.1. Rotary control device exception

Rotary control devices are not required during tripping activities where an alternative well barrier is in place.

8.3.2.4. Well control

The volume and properties of fluid required to kill the well shall be known at all times and the materials and equipment required to make up a kill fluid shall be available on site during underbalanced drilling or managed pressure drilling operations.

8.4. Sidetracking

8.4.1. Isolating wellbore prior to sidetracking

Any flow zones in the original wellbore below the kick off point for a sidetrack shall be permanently isolated prior to sidetracking unless the original wellbore will be produced as part of a multi-lateral well.

8.4.2. Decommissioning a well with sidetracks

The design of well decommissioning activities shall demonstrate that all branches of a well are properly isolated.

8.5. Hydraulic fracturing and flowback operations

8.5.1. Hydraulic fracturing operation design

Where hydraulic fracturing operations are planned for a well, the well and hydraulic fracturing operations shall be designed:

a) to take into account the location and characteristics of known geohazards and any other wells near the well to be hydraulically stimulated,

b) to define the target stratigraphic horizon to be hydraulically fractured and the surrounding stratigraphy that will form fracture barriers, and

c) so that hydraulic fractures are contained within the proposed target stratigraphic horizon and that the target stratigraphic horizon is sufficiently separated from aquifers.

The WOMP shall demonstrate how the well trajectory, perforation placement, hydraulic fracturing operations, the anticipated hydraulic fracture geometry and the risks of hydraulic fracture growth outside of the target stratigraphic horizon are to be managed for hydraulic fracturing operations in subject wells.

8.5.2. Well integrity verification for hydraulic fracturing operations

Well integrity shall be verified as soon as reasonably practicable before and after hydraulic fracturing operations.

The WOMP shall include a well integrity verification, monitoring, surveillance and maintenance program (section 5.2) for hydraulic fracturing and flow back operations for subject wells.

8.5.2.1. Pressure test

Well integrity verification shall include a well barrier pressure test.

8.5.2.2. Maximum allowable operating pressure during hydraulic fracturing operations

A MAOP for hydraulic fracturing operations shall be established for each well where hydraulic fracturing operations will be conducted. The MAOP for hydraulic fracturing operations shall not exceed the maximum pressure achieved in the well pressure test (section 8.5.2.1).

8.5.3. Well annuli monitoring during hydraulic fracturing operations

Pressure communication between casing annuli shall be monitored and controlled while conducting hydraulic fracturing operations.

The well integrity verification, monitoring, surveillance and maintenance program (section 5.2) for hydraulic fracturing and flow back operations in a WOMP shall include a description of how pressure communication between casing annuli shall be monitored and controlled for subject wells.

8.5.4. Well pressure kickout and relief during hydraulic fracturing operations

The pressure kickout on pump units and in-line pressure relief valves (where utilised) shall be set below the MAOP for the well (section 8.5.2.2).

8.6. Suspended wells

8.6.1. Well barrier requirements for suspended wells

Suspended wells shall have at least one deep-set barrier. Acceptable WBEs for a suspended well shall:

a) be a mechanical plug or cement plug,

b) be set adjacent to an in-situ barrier formation,

c) be set adjacent to a minimum of 30 m MD of good annular cement,

d) be independent of the wellhead or tree,

e) not be operable from the surface, and

f) not include sub-surface safety valves.

8.6.2. Suspended well fluid column

The fluid column in a suspended well shall be designed so that it does not cause degradation of the existing WBEs.

8.7. Well decommissioning

8.7.1. Well decommissioning design

Wells shall be decommissioned:

a) using a three-phase process, and

b) so that time dependant degradation of well integrity is accounted for as far as practical.

The WOMP shall demonstrate how the well decommissioning operations and well barriers have been designed for subject wells.

8.7.1.1. Well decommissioning phase 1: Reservoir isolation

Where a well has intersected one or more high potential flow zones, these zones shall be isolated in the first phase of decommissioning.

8.7.1.2. Well decommissioning phase 2: Intermediate decommissioning

All flow zones in a well that have not been isolated in phase 1 that are below the surface casing shoe for the well shall be isolated in phase 2.

8.7.1.3. Well decommissioning phase 3: Final decommissioning

Flow zones in the surface casing section of a well shall be isolated in phase 3. In addition, the surface expression of the well shall be removed.

8.7.2. Decommissioned well barriers

8.7.2.1. Decommissioned well minimum number of barriers

The number of barriers required to isolate flow zones in a decommissioned well shall be as required in section 4.4.

8.7.2.1.1. Decommissioned well barrier cross flow

Where an interest holder intends to group flow zones so that they are isolated together they shall be able to demonstrate that the risks are acceptable, considering:

a) fluid composition,

b) pressure regime at the time of decommissioning,

c) pressure regime subsequent to decommissioning,

d) potential for cross flow between zones, and

e) potential for cross flow between wells.

8.7.2.2. Decommissioned well barrier general requirements

Permanent well barriers in decommissioned wells shall be designed to restore the natural barrier to flow (restoring the cap rock) as shown in Figure 1. Permanent well barriers shall:

a) be set above the zone of flow potential,

b) be set adjacent to an in-situ barrier formation (a cap rock) that:

    a. is impermeable,

    b. laterally continuous,

    c. has adequate strength, and

    d. adequate thickness.

c) prevent flow along annular interfaces, and

d) extend formation to formation, across the entire cross-section of the well including all annuli.

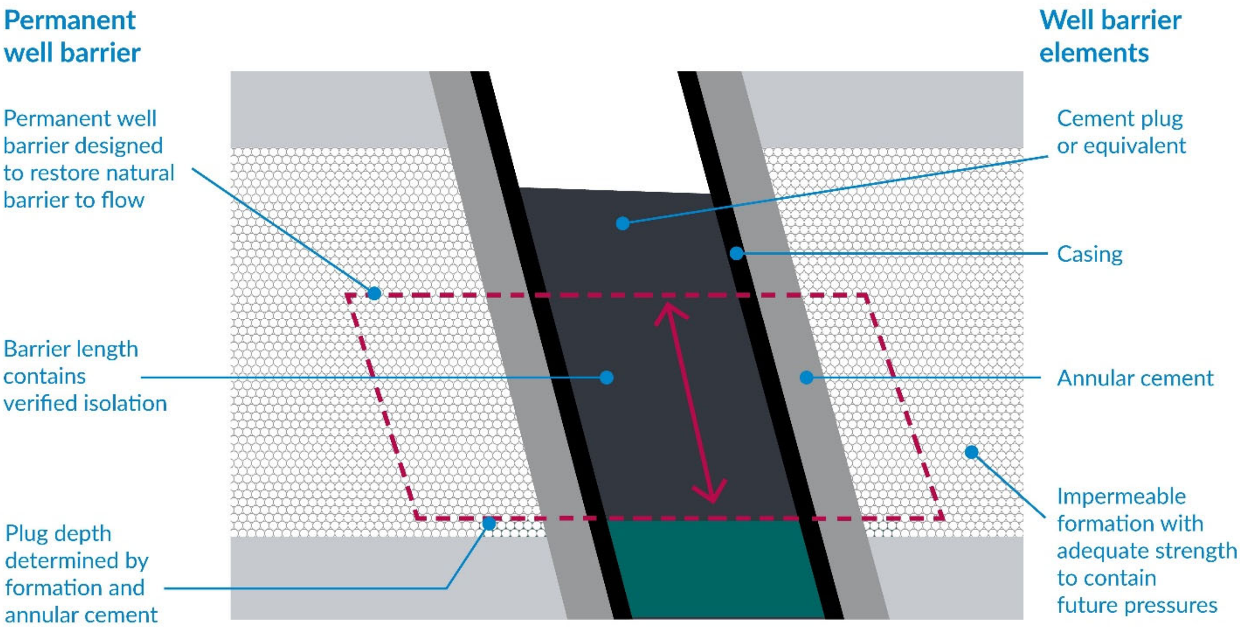

Figure 1: Well barrier general requirement for isolation of petroleum bearing zones

8.7.2.2.1. Decommissioned well primary sealing material

The primary sealing material for decommissioned wells shall be:

a) cement, or

b) a material that has been demonstrated to have equivalent or better performance than cement for the purposes of placement and long term well integrity.

8.7.2.2.2. Decommissioned well cement barrier length

Annular cement or cement plugs used as a single permanent WBE in decommissioning shall have a minimum length of 50 m MD (See Figure 2), and:

a) cement plugs placed in the wellbore shall be adjacent to good annular cement for 50 m MD (if the 50 m MD length of annular cement is made up of discrete zones of good cement, the cement plug shall span the interval to cover a cumulative annular cement length of 50 m), and

b) where distinct flow zones are less than 50 m MD apart, the length of cement shall extend across the entire interval between the zones.

Where a combination WBE is used in place of two permanent WBE (See Figure 2), cement plugs placed in the wellbore:

a) shall have a minimum length of 100 m MD, and

b) overlap with good annular cement for a minimum of 100 m MD.

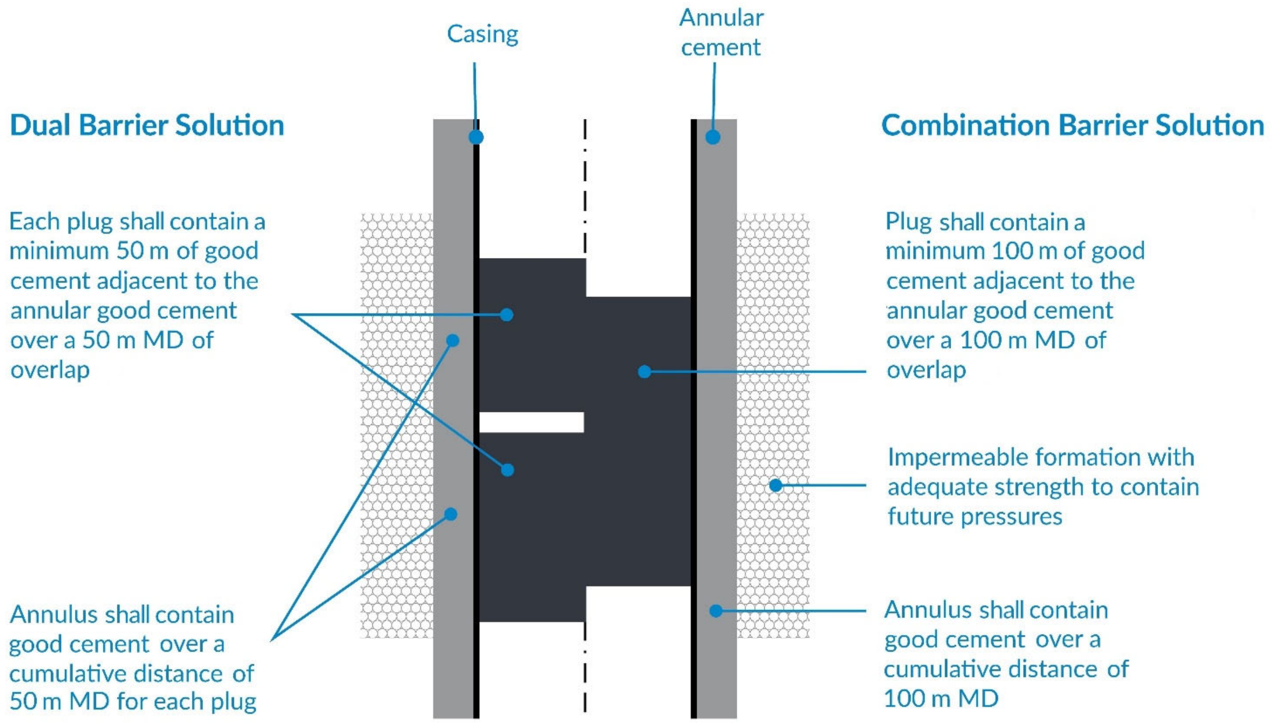

Figure 2: Cement barrier length requirements for dual and combined barriers

8.7.2.2.3. Decommissioned well barrier element requirements

In addition to all other requirements of this code, WBEAC shall demonstrate:

a) the WBE is suitable for a decommissioned well, and
b) the time dependent WBE material integrity is appropriate for use in well barriers for a decommissioned well.

The WOMP shall include these acceptance criteria in the WBEAC table for the WBE for subject wells.

8.7.2.3. Decommissioned well barrier pre-decommissioning integrity verification

The integrity of any WBE that will form part of a well barrier in a decommissioned well shall be verified according to their WBEAC prior to placing any additional barriers in the well that have the potential to prevent access. If a WBE cannot be verified, it shall not be used as part of a well barrier for a decommissioned well.

8.7.2.4. Decommissioned well barrier integrity verification

The integrity of any WBE that will be placed into a well to form part of a permanent well barrier in a decommissioned well shall be verified according to their WBEAC:

a) immediately after placement, and
b) prior to placing any additional barriers in the well that have the potential to prevent access.

8.7.3. Decommissioned well monitoring

8.7.3.1. Decommissioned well monitoring: phase 1

The integrity of permanent well barriers established during phase 1 decommissioning shall be monitored to demonstrate the integrity of a decommissioned well. The monitoring program shall have acceptance criteria. The monitoring period shall be:

a) A minimum of 6 months, or
b) A period less than 6 months where:
    a. all barriers installed during phase 1 decommissioning have been verified to a high degree of certainty, and
    b. the duration of monitoring is demonstrated to be appropriate for identified risks.

The WOMP shall describe the monitoring program demonstrating that it is appropriate for identified risks.

8.7.3.2. Decommissioned well monitoring: phase 2

The integrity of permanent well barriers established during phase 2 decommissioning shall be monitored to demonstrate the integrity of a decommissioned well. The monitoring period shall be a minimum of 6 months. The monitoring program shall have acceptance criteria.

The WOMP shall describe the monitoring program demonstrating that it is appropriate for identified risks.

8.7.4. Well decommissioning: phase 3

Phase 3 well decommissioning shall only take place once phase 2 decommissioning has been completed and phase 1 and phase 2 monitoring confirms the integrity of the well.

8.7.4.1. Well decommissioning phase 3 objectives

Phase 3 well decommissioning shall be designed so that:

a) the wellbore cannot become a pathway for water flow from the surface,
b) aquifers within the surface casing interval are isolated from each other, and
c) no annuli are available to provide a potential path for fluid flow between zones.

8.7.4.2. Well decommissioning phase 3 barrier requirements

Well barriers set in phase 3 shall meet the requirements set out in section 8.7.2.2. In addition, a shallow barrier shall be placed so that it achieves the aquifer isolation requirements in section 4.4.3 and extends to within a minimum of 15 m from the surface.

8.7.4.3. Removal of surface expression of the well

The surface expression of the well shall be removed by:

a) cutting casing and removal of cellar components at a minimum of 1.5 m below ground level,
b) placing a cement cap 0.3 m thick with a diameter 0.5 m greater than the diameter of the conductor hole, and
c) backfilling with soil to ground level.

8.7.4.3.1. Well marker

A steel marker plate cut from corrosion resistant alloy or similar grade steel for corrosive environments shall be installed horizontally on the cement cap prior to backfilling. The marker plate shall detail the following:

a) the identifying name of the well or bore,

b) the total depth in metres of the well or bore,

c) the date the well or bore was decommissioned, and

d) the marker plate shall be covered with soil to ground level.

8.7.5. Fluid column in decommissioned wells

The fluid column shall not be considered as a WBE in decommissioned wells.

8.7.5.1. Fluid column specification for well decommissioning

The fluid column in decommissioned wells shall be designed so that it does not cause degradation of the existing WBEs.

The WOMP shall describe the critical properties and specifications of the fluids used during well decommissioning activities and those left in the well for subject wells.

8.7.6. Post decommissioning monitoring

Wells shall be monitored after phase 3 decommissioning until such time that the petroleum titles have been surrendered. The monitoring program shall be based on a risk assessment. The monitoring program shall have acceptance criteria.

The WOMP shall describe the monitoring program for fully decommissioned wells demonstrating that it is appropriate to the risks for subject wells.