

Code of Practice

For the construction and abandonment of coal seam gas and petroleum wells, and associated bores in Queensland

Petroleum and Gas Inspectorate

Version 1

1 September 2018

Table: Document history

Version number	Date of publication	Date of effect	Key changes
V1	1 September 2018	1 September 2018	This Code is a consolidation of the Code of Practice for the construction and abandonment of coal seam gas wells and associated bores in Queensland, Edition 3.0, 19 May 2017 and the Code of Practice for the construction and abandonment of petroleum wells and associated bores in Queensland, Edition 1.0, 3 Mar 2016, with some revisions to align with the commencement of Petroleum and Gas (Safety) Regulation 2018

This publication has been compiled by the Petroleum and Gas Inspectorate, Resources Safety and Health, Department of Natural Resources, Mines and Energy, with significant input from the Queensland petroleum lease operators and stakeholders.

© State of Queensland, 2018

The Queensland Government supports and encourages the dissemination and exchange of its information. The copyright in this publication is licensed under a Creative Commons Attribution 4.0 International (CC BY 4.0) licence.

Under this licence you are free, without having to seek our permission, to use this publication in accordance with the licence terms.



You must keep intact the copyright notice and attribute the State of Queensland as the source of the publication.

Note: Some content in this publication may have different licence terms as indicated.

For more information on this licence, visit <https://creativecommons.org/licenses/by/4.0/>.

The information contained herein is subject to change without notice. The Queensland Government shall not be liable for technical or other errors or omissions contained herein. The reader/user accepts all risks and responsibility for losses, damages, costs and other consequences resulting directly or indirectly from using this information.

Table of contents

1	Overview.....	1
1.1	Background	1
1.1.1	Other relevant legislations	1
1.2	Purpose	2
1.3	Scope and application	2
1.3.1	Scope of this Code of Practice.....	2
1.3.2	Alternate means of compliance.....	3
1.3.3	Application.....	3
2	Coal seam gas wells	4
2.1	General description of coal seam gas drilling activities	4
2.1.1	Introduction	4
2.1.2	Well construction process	5
2.1.3	Site Identification and location	5
2.1.4	Risk assessment.....	6
2.2	Principles, means of compliance and good industry practices	6
2.2.1	Well design.....	6
2.2.2	Casing	8
2.2.3	Cementing.....	9
2.2.4	Wellheads	13
2.2.5	Well control equipment	13
2.2.6	Drilling fluids.....	14
2.2.7	Evaluation, logging, testing and coring	15
2.2.8	Well integrity management	17
2.2.9	Abandonment of wells, bores and other drill holes	19
2.2.10	Recording and reporting data	28
3	Petroleum wells	30
3.1	General description of petroleum well life cycle activities	30
3.1.1	Introduction	30
3.1.2	Outline of the well life cycle phases	30
3.1.3	Site identification and location	31
3.1.4	Risk management/risk identification	32
3.1.5	Management of change	32
3.2	Principles, means of compliance and good industry practices	32
3.2.1	Well life cycle records, reporting and notification.....	32
3.2.2	Well design and well barriers	33
3.2.3	High pressure high temperature petroleum well design	35
3.2.4	Working with hydrogen sulphide (H ₂ S)	36

3.2.5	Casing and tubing	38
3.2.6	Primary cementing	41
3.2.7	Aquifer isolation.....	46
3.2.8	Wellheads	47
3.2.9	Well control	48
3.2.10	Drilling fluids.....	49
3.2.11	Well evaluation, logging, testing and coring	52
3.2.12	Hydraulic stimulation/flow-back operations.....	54
3.2.13	Well integrity Management	56
3.2.14	Workover and Intervention.....	57
3.2.15	Well suspension and abandonment.....	58
3.2.16	Recording and reporting data	65
4	Additional and alternative requirements for water bores	66
4.1	Introduction.....	66
4.2	General water bore construction requirements	66
4.2.1	Principles.....	66
4.2.2	Means of compliance	66
4.3	Maximising water entry for constructed water bores.....	67
4.3.1	Principles.....	67
4.3.2	Means of compliance	67
4.3.3	Good industry practice	67
4.4	Water bore development	69
4.4.1	Principles.....	69
4.4.2	Good industry practice	69
4.5	Headworks for water bores	70
4.5.1	Principles.....	70
4.5.2	Means of compliance	70
4.5.3	Good industry practice	70
4.6	Single casing string, single aquifer bores.....	70
4.6.1	Principles.....	70
4.6.2	Means of compliance	70
4.6.3	Good industry practice	71
4.7	Areas where groundwater is corrosive.....	71
4.7.1	Principles.....	71
4.7.2	Means of compliance	71
4.8	Injection bores	71
4.8.1	Principles.....	71
4.8.2	Means of compliance	72
4.9	Conversion of CSG & petroleum wells to water bores.....	72

4.9.1	Principles.....	72
4.9.2	Means of compliance	72
4.9.3	Good industry practice	72
Appendix 1 – Glossary		73
Appendix 2 – Industry standards		79
Appendix 3 – Cooper / Eromanga Basin Aquifers.....		82
Appendix 4 - Examples of standard Surat abandonment schematics		83
Appendix 5 – References		84

Table of figures

Figure 1: Illustration of the scope of this Technical Specification	17
Figure 2: Open hole/ uncased hole section (no lost circulation and not approved for commingling) ...	22
Figure 3: Cased hole section	23
Figure 4: Casing shoe with open hole below	24
Figure 5: Casing shoe with open hole/un-cemented liner below (with lost circulation)	25
Figure 6: Cut and recovered casing/liner or Production liner laps	26
Figure 7: Perforated casing.....	27
Figure 8: Cement encased casing - well barrier	60
Figure 9: Open hole / uncased hole section	61
Figure 10: Cased hole section	61
Figure 11: Casing shoe with open hole below	62
Figure 12: Casing shoe with open hole below (with lost circulation)	62
Figure 13: Cut and recovered casing.....	63
Figure 14: Perforated casing.....	63
Figure 15: Production or HPHT zone Liner Laps.....	64

Table of tables

Table: Document history	2
Table 1: Typical design factors used in the hydrocarbon industry.....	39
Table 2: Property and primary cement criteria.....	42
Table 3: Primary cementing slurry design considerations	43
Table 4: Verification and evaluation recommendations for primary cement jobs	44
Table: Terms and definitions.....	73

1 Overview

1.1 Background

In Queensland, petroleum and gas safety is regulated under the *Petroleum and Gas (Production and Safety) Act 2004* (P&G Act), and the *Petroleum and Gas (Safety) Regulation 2018* (P&G Regulation). This legislation is administered and enforced by the Petroleum and Gas Inspectorate (the Inspectorate).

Under the legislation, petroleum tenure applies to both conventional and unconventional resources including coal seam gas (CSG). In practice, there are technical differences between a well drilled for CSG and a conventional resource. This consolidated Code of Practice for the construction and abandonment of coal seam gas and petroleum wells and associated bores in Queensland comprises the former construction and abandonment code for CSG wells requirements (in Part 2) and the former construction and abandonment code for petroleum wells requirements (in Part 3) and combines the associated bore requirements in Part 4. Accordingly, this Code addresses CSG wells and conventional petroleum wells separately. For the purpose of this Code, the terms 'CSG well' and 'petroleum well' are used, and mean the following:

- 'CSG well' means a *prescribed well*, as defined in the P&G Regulation, that is drilled on a petroleum authority to explore for or produce natural gas from a coal seam reservoir.
- 'Petroleum well' means a *petroleum well*, as defined in the P&G Act, other than a CSG well.

Well integrity is fundamental to ensuring sustainable petroleum production, ensuring risk can be managed to an acceptable level and protecting aquifers during the well life cycle. This Code addresses safety and environmental issues in the construction and abandonment (decommissioning) of petroleum and CSG wells and associated bores.

The P&G Regulation establishes that the means of compliance in this Code are to be complied with for the drilling, converting and abandoning of petroleum wells, CSG wells and water bores.

1.1.1 Other relevant legislations

In Queensland, petroleum activities are also subject to the *Environmental Protection Act 1994*. Under an environmental authority, petroleum tenure holders are generally required to monitor, identify and manage potential risks to the environment.

The *Water Act 2000* (the Water Act) provides a regulatory framework for petroleum tenure holders to monitor, assess and manage the impacts of their underground water rights on water bores, aquifers and springs. Specification for water bores constructed under the Water Act are provided for in the Minimum Construction Requirements for Water Bores in Australia (MCRWBA) and the Minimum Standards for the Construction and Reconditioning of Water Bores that Intersect the Sediments of Artesian Basins in Queensland (MSWBIAB).

1.2 Purpose

The purpose of this Code is to ensure that all petroleum wells, CSG wells and associated bores are constructed, maintained and abandoned to a minimum acceptable standard resulting in long-term well integrity, containment of petroleum and the protection of groundwater resources. This Code identifies industry standards and good oilfield practice for oil and gas well design.

It provides a way for petroleum tenure holders to comply with their obligations under Queensland's petroleum legislation. However, it is not intended to discourage or prevent petroleum tenure holders from adopting an alternative means of achieving a level of risk that is equal to or less than the level of risk that would be achieved by complying with this Code.

The design of this Code complements the petroleum tenure holder's internal risk assessment processes, operating standards and procedures by outlining a recommended process to ensure that:

- a) the environment and groundwater resources are protected
- b) risk to the public and workers is managed to a level as low as reasonably practicable
- c) regulatory and applicable Australian and international standards/requirements, as well as the petroleum tenure holder's standards, are understood and implemented where appropriate
- d) the life of a petroleum well, CSG well or associated bore is managed effectively through appropriate design and construction techniques and ongoing well integrity monitoring.

1.3 Scope and application

1.3.1 Scope of this Code of Practice

This Code applies to petroleum wells, CSG wells and water bores constructed by petroleum tenure holders on their tenures for both conventional and unconventional oil and gas exploration and production. It covers conversion of CSG wells and petroleum wells to water bores.

This Code covers all petroleum well types including exploration, appraisal, monitoring, injection and production wells, and water bores, including water observation, water supply and water injection bores.

This Code applies to the following well life cycle phases:

- a) preliminary well planning and well design
- b) well construction (up to the production wing valve of the well head/Christmas tree)
- c) well evaluation and hydraulic fracture stimulation activities
- d) well integrity management
- e) well suspension and abandonment
- f) construction of new water bores by petroleum tenure holders
- g) conversion of petroleum wells and CSG wells to water bores.

Within those stages, it considers equipment and material selection, risk assessment (both safety and environment), industry practices, monitoring and reporting.

This Code does not:

- a) address the manufacture or the certification of drilling rigs or associated equipment
- b) refer to any necessary technical training of the various operatives.

1.3.2 Alternate means of compliance

This Code addresses industry standards and good oilfield practice for oil and gas well construction, conversion and abandonment, and Australian standards for water bore construction and abandonment.

If a petroleum tenure holder proposes an alternate means of compliance to the stated means of compliance in this Code, the proposal is to be submitted to the Chief Inspector, Petroleum and Gas for written approval. Alternate means of compliance is authorised by written approval from the Chief Inspector.

1.3.3 Application

The contents of this Code falls into the following categories:

- a) Principles: these are the fundamental requirements that **must** be adhered to during the lifecycle of the well or bore.
- b) Means of compliance: these are the requirements that are enforceable by the regulator and must be complied with. By adhering to these requirements, the well or bore will meet the Principles.
- c) Good industry practices: these are recommended practices, methods and techniques to assist petroleum tenure holders to satisfy the means of compliance. These are not in themselves means of compliance or principles. The terms **should** or **may** are used for good industry practice recommendations.

Where there is a conflict between this Code and the safety requirements or other relevant provisions in the P&G Act or P&G Regulation, the provisions of the P&G Act or P&G Regulation (as the case may be) prevail.

Compliance with this Code is directed at the petroleum tenure holder, being the entity responsible for management of the safe operations of exploring for and producing petroleum on the land to which a petroleum tenure applies. The petroleum tenure holder should ensure that all parties undertaking work covered by this Code (e.g. drilling contractors) also comply with it.

Part 4 of this Code: *Additional and alternative requirements for water bores*, provides design options for drilling a water bore. Where the assessments required under part 4 of this Code determine there is significant risk associated with drilling a water bore through hydrocarbons, then such a bore must be constructed according to the requirements in Part 2: *Coal seam gas wells*.

A glossary for specific terms, abbreviations and acronyms used in this Code is provided in Appendix 1 – *Glossary*.

Relevant industry standards, recommended practices, technical reports and industry experience should be considered in the design and implementation of the well construction process. This includes the use of standards and specifications developed by the American Petroleum Institute (API) and the International Organization for Standardization (ISO).

A list of relevant industry standards and recommended practices is provided in Appendix 2 – *Industry Standards*.

2 Coal seam gas wells

This Part applies to CSG wells and provides a way for petroleum tenure holders producing CSG, to comply with their obligations under Queensland's petroleum legislation.

2.1 General description of coal seam gas drilling activities

2.1.1 Introduction

There are generally two phases of CSG operations—exploration and production. Once a well is no longer required for CSG operations, it is abandoned. Abandoning wells involves:

- a) sealing of wells to prevent the intermixing of fluids and pressures between coal seams and aquifers
- b) preventing the escape of fluids to surface
- c) preventing injury and harm to people and the environment

It also includes the process of decommissioning as described in legislation.

CSG exploration drilling aimed to identify gas bearing reservoirs and sediments generally targets a large area, with typically one well per 30 to 60 km² depending on the locality.

If exploration indicates the potential for gas production, pilot wells may be drilled to confirm production performance and to further define reservoir properties. A pilot test is essentially a small scale production trial, with associated infrastructure.

Production wells are typically spaced at some 600–1200 m or more, and may operate for many years or even for several decades.

In addition to CSG wells, a range of activities associated with gas production means tenure holders require the following water bores.

- a) Water observation bores to enable impacts of CSG operations to be quantified.
- b) Water supply bores needed for undertaking their activities, and may be required for 'make good' purposes.
- c) Injection bores required for the injection of treated associated water or brine.
- d) Water bores converted from a CSG well for use by a landowner or other stakeholder.

This Code provides standards and guidelines for construction operations for the range of wells and bores needed by CSG companies.

2.1.2 Well construction process

The main steps involved in CSG well construction and abandoning for either exploration or production are:

- a) site identification and location
- b) site (or 'lease') access and preparation
- c) well design
- d) work program issued for well construction
- e) drilling
- f) logging and/or testing
- g) running and cementing casing
- h) well stimulation (if required)
- i) well completion
- j) CSG production
- k) well and bore abandoning (decommissioning) and site rehabilitation.

During the normal course of any drilling program there will be various company and contractor personnel who will need to travel to the drill site. These people are required for:

- a) site checks and surveying
- b) earthworks (e.g. for access to site and to clear the drill pad area)
- c) drilling rigs and support vehicles
- d) water carting
- e) specialist testing service providers
- f) well site supervision and geological personnel
- g) cement and casing deliveries
- h) well intervention/well treatment equipment such as workover rigs
- i) support vehicles/services.

2.1.3 Site Identification and location

All wells and water bores are first planned in a desktop process to identify potential or suitable sites within known constraints such as tenement boundaries, topographic constraints and environmental restrictions.

Potential exploration well sites additionally have a desktop review undertaken to identify locations which may best define the geology of an area or project. In some cases this may be based on earlier seismic surveys.

After the desktop assessment it is essential to then 'ground-truth' the proposed site, and at this stage it is critical that consultation with the relevant stakeholders takes place to choose the most appropriate site and consider all other constraints (e.g. access routes).

In most cases there is reasonable flexibility in locating proposed wells to avoid particular sites. As a general rule there is more flexibility to move exploration wells than to move production wells. Well sites can usually be identified that present the least impact to the environment and existing land use.

Petroleum companies are required by law to conduct various checks on any site where works are proposed.

These checks are either office or field-based, and may include:

- a) environmental checks (e.g. distance from specific flora and fauna communities)
- b) cultural heritage inspections (particularly with regard to indigenous cultural heritage)
- c) topography restrictions and issues (avoiding water courses, ravines, steep cliff faces)
- d) land use restrictions (including consultation with landholders)
- e) other stakeholder liaison.

2.1.4 Risk assessment

Petroleum tenure holders must carry out risk assessment to identify the risks that may occur during well or bore construction, operation and abandonment. Risks to be managed must include, as a minimum, site access and preparation, well integrity, groundwater protection and safety of personnel and the community.

Once agreement is reached on the location of a well, the primary considerations in preparing a drill site are safety and the environment.

For safety of both site personnel and landholders, well sites should be sized and prepared appropriately and may also be fenced for safety and to provide a barrier to exclude livestock and large wildlife.

The environmental procedures used in preparing the site may include the stockpiling of topsoil which is kept separate for rehabilitation, and minimising the footprint where possible.

In most cases ground pits (or sumps) are excavated to hold drilling or waste water. Sufficient storage for wellsite activities needs to be provided in these sumps which may be lined with heavy grade plastic if required.

Generally it may be necessary to dig a cellar, which is approximately two metre square and two metre deep, to house the blowout preventer (BOP) and the lower section of the wellhead. The BOP is safety-specific equipment which allows the well to be sealed at surface in case of unplanned flow from the well, or a build-up of pressure within the well. This serves to minimise the risk of release of any well fluids to the environment.

2.2 Principles, means of compliance and good industry practices

This section outlines requirements for construction of CSG wells and water bores in identified high risk areas, as determined in Part 4 of this Code.

2.2.1 Well design

2.2.1.1 Principles

CSG wells are to be designed to ensure the environmentally sound, safe production of gas (predominantly methane) and other wellbore fluids by containing them inside the casing, protecting groundwater resources, isolating the productive formations from other formations, and by proper execution of treatment/stimulation and/or completion operations.

Well design and construction must ensure that no leaks occur through or between any casing strings. The fluids produced from the well must travel directly from the producing zone to the surface inside the well conduit, without contamination of groundwater or other aquifer resources.

All CSG wells therefore must be designed to ensure the safe and environmentally sound production of gas by:

- a) preventing any cross-flow contamination between hydrocarbon bearing formations and aquifers
- b) ensuring that gas is contained within the well and associated pipework and equipment without leakage
- c) ensuring zonal isolation between different aquifers is achieved¹
- d) prevent/ avoid the introduction of substances that may cause environmental harm.

2.2.1.2 Means of compliance

The design basis for CSG wells must:

- a) consider casing setting depths that take into account aquifer and production zone locations, and the requirements for well control
- b) provide for installation of pressure control equipment (PCE) based on risk assessment, e.g. BOP equipment to API Standard 53
- c) use appropriate casing weight and grade, and casing running procedures
- d) use appropriate well design and construction materials
- e) use appropriate casing centralisation
- f) use engineered cement slurry and effective cement placement techniques
- g) ensure all fluids produced from the well travel directly from the production zone to the surface without cross contamination.

2.2.1.3 Good industry practice

- a) Review offset well information to assist in the design process for new wells.
- b) Include nearby water bores in the record keeping and data-set as part of the offset review.
- c) Consider offset data that details any evidence of tubular corrosion. If corrosion has been observed, petroleum tenure holders will need to conduct a risk assessment and take action to ensure well integrity.
- d) Note formation horizons or zones, from which water bores produce, during the offset well review to assist the placement of surface and/or production casing.
- e) Use sustainable construction practices and operating procedures e.g. to conserve water usage and minimise waste.
- f) All CSG well designs and construction procedures should include contingency planning to mitigate the effects of failures in the event of unplanned process upsets or events during construction.
- g) Select casing hardware, including float equipment, centralizers, cement baskets, wiper plugs (top and bottom), stage tools and external casing packers, as appropriate as part of the well design to ensure the required zonal isolation.

¹ Note: Some formations such as the Walloons coal measures or Bandanna formation are considered as a single entity and do not require zonal isolation within the formation. The regulator should be consulted about other formations.

2.2.2 Casing

2.2.2.1 Principles

Casing should be designed to withstand the various compressive, tensile and bending forces that are exerted while running-in the hole, as well as the collapse and burst pressures that it may experience during different phases of the well's life e.g. cementing, pressure testing, stimulation and production cycles.

Casing strings should be designed to facilitate installation of PCE.

As well as providing a mechanism of extracting gas from the production zones, casing acts to protect other resources such as groundwater.

2.2.2.2 Means of compliance

- a) Casing, casing connections, wellheads, and valves used in CSG wells must be designed to withstand the loads and pressures that may act on them throughout the entire well life cycle.
This includes casing running and cementing, any treatment pressures, production pressures, any potential corrosive conditions, and other factors pertinent to local experience and operational conditions.
- b) For CSG wells, all surface and production casing in pressure containing applications² must be designed to withstand the loads, pressures and temperatures that may act on them throughout the entire well life cycle
- c) In all CSG wells, a conductor pipe does not need to meet the requirements under (a) and (b) above.
- d) Barriers shall be installed to prevent surface pollutants from entering the well, and prevent wellbore fluids and gas from escaping to the surface environment.
- e) When designing casing strings and casing connections for CSG wells, CSG operators must design each well's casing string using appropriate design safety factors.
For example, typical design safety factors used in the hydrocarbon industry at large are 1.1 for burst, 1.0 for collapse, 1.3 for static tension and 1.25 for tri-axial analysis. The design safety factors used by a CSG operator need to be appropriate for the anticipated well life, service conditions and local experience.
- f) To verify casing integrity during the well construction process, casing must be pressure tested prior to drilling out for the next hole section (in the case of surface or intermediate casing), and prior to completion operations commencing (in the case of production casing). The test pressure must be greater than the anticipated formation pressure possible at the surface, but must not exceed the burst pressure rating of the casing with the design safety factor applied.
- g) Minimum casing setting depth should be sufficient to meet the isolation requirements of groundwater aquifers and provide an acceptable kick tolerance for the next hole-section to be drilled. The kick tolerance criteria shall be selected by the operator and will be dependent upon knowledge of the local pore pressure and fracture gradient profiles, and of the likely kick conditions in the well.
 - i. If it is intended to convert a CSG well to a water supply bore, the surface casing shall not be set shallower than 60 m true vertical depth.
 - ii. When the surface casing is set shallower than 60 m true vertical depth (TVD), the intermediate or production casing must be cemented to surface.

² Note: 'Pressure containing applications' include all applications where the integrity of the casing is required to maintain well control.

- h) Steel casing connections must be made up to ensure an aligned, round, secure, and leak proof joint
 - i. Only threaded casing connections are permitted in construction of CSG wells.

2.2.2.3 Good industry practice

- a) For casing run in CSG wells, pipe body and connections should have verifiable properties (i.e. in terms of burst, collapse and tensile strengths).

Note: casing manufactured to API specifications by definition must meet strict requirements for compression, tension, collapse and burst resistance, as well as quality and consistency.

- b) When making up a casing connection it is important to apply the recommended torque. Too much torque may over-stress the connection and may result in failure of the connection. Too little torque may result in leaks at the connection.
- c) The correct use of casing dope, and its impact on torque make-up should be incorporated into casing running procedures.
- d) Operators should consider the potential impact of high casing pressure on cement bond quality when determining pressures for any casing tests carried out before cement has properly set.
- e) Petroleum tenure holders, their drilling contractors and their well site supervisors should review and ensure compliance with the work program to run, install and test all casing strings during well construction.
- f) Long term monitoring and recording of the casing condition should be undertaken.

2.2.3 Cementing

2.2.3.1 Principles

CSG wells need to be cemented to:

- a) prevent migration paths and isolate the targeted zone from other formations
- b) protect groundwater resources from contamination
- c) maintain aquifer pressures and quality
- d) obtain and maintain well integrity
- e) protect the casing from corrosion.

2.2.3.2 Means of compliance

- a) To prevent interconnection between zones of differing pressure and water quality:
- i. All surface casing must be cemented from shoe to surface.
 - ii. For cementing production and intermediate casing, operators must design to ensure cement is either brought to surface or designed to an appropriate safety overlap distance of at least 50 m back inside the previous casing shoe. However, where operators choose not to bring cement to surface, they should consider that after abandonment, two adjacent cement barriers across all aquifers will be required as per 2.2.9.2 (h)h) of this Code.
 - iii. Where cement is not returned to surface, wire-line logging or pressure testing must be performed and recorded, to verify isolation of the casing / casing annulus has occurred, after the cement has reached a compressive strength of 500 psi. at surface conditions.
 - iv. Testing pressures shall take into account collapse pressure of the inner casing string and fracture gradient at the outer casing shoe.
 - v. Production casing cement must be designed so that the base of the cement is no more than 30 m TVD above the predicted depth of the shallowest production zone. If, once final pressure tests and/or wire-line evaluation are complete, achievement of the cementing objectives cannot be reliably demonstrated then written notification must be emailed to: PGIHotline@dnrme.qld.gov.au
- This notification must be sent as soon as reasonable practicable and no later than two business days upon positive confirmation of an absence of zonal isolation. Subsequently, the integrity of the well must be reviewed and measures put in place prior to bringing the well on production to ensure well integrity for the lifetime of the well.
- b) Cement constituents and properties must be suitable for the intended conditions of use and used in compliance with the relevant material safety data sheets (MSDS) requirements.³
- c) Appropriate cement laboratory testing procedures must be carried out in advance of the well being drilled to ensure the resulting slurry meets the requirements of the well design. The testing, as a minimum, must include compressive strength development with time. In the case where a number of similar wells are drilled in an area with constant cement materials and mix water properties, then a representative lab test may suffice.
- d) Wait on cement setting time prior to:
- i. Slacking off or removing blowout preventers (BOPs) must be based on the cement achieving a minimum of 100 psi (0.7 MPa) compressive strength at the temperature of any potential flow zone in the annulus just cemented. Alternatively, operators may use a mechanical barrier that is compliant with API 65 – Part 2 and tested to verify a pressure seal prior to removing BOPs.
 - ii. Drill out must equate to the laboratory testing time for cement surrounding the casing shoe to have achieved a minimum compressive strength of 500 psi (3.5 MPa).
- e) Operators must ensure all zones (both hydrocarbon and groundwater aquifers) are isolated with cement with a minimum ultimate compressive strength of 500 psi (3.5 MPa).

³ Note: API RPs 10A, 10B, 10D and 65-2, Guidance Document HF-1 and Technical Reports 10TR are the recommended benchmarks for cementing wells.

- f) Operators must determine and document in their well procedures a minimum required ultimate compressive strength for cement slurries to be used across zones which may be hydraulically fracture stimulated.

For example, requirements for ultimate compressive strength of 1400 psi (10 MPa) to 2000 psi (14 MPa) are often used in the hydrocarbon industry for cement across zones requiring fracture stimulation treatment.

- g) Operators must ensure that the required compressive strength slurry for fracture stimulation also be placed at least 150m above the shallowest target coal to be hydraulically fractured.

Refer: API Guidance Document HF-1

- h) During all cement jobs where the casing to be cemented is installed to the surface, cement returns to surface must be continuously monitored and recorded to confirm the effectiveness of the cement placement. Pressures during the cement job and in particular immediately prior to plug bump must be similarly recorded as a potential indicator of height of cement column and downhole problems.
- i) Free water content of the cement is specified as less than 2% using the free water test outlined in API RP 10B-2.
- j) Casing centralisation simulation must be undertaken for the casing centralisation plan to achieve a minimum of 70% standoff across the total cementing depth.
- i. 70% standoff is equal to 23mm for 9-5/8" casing in 12-1/4" hole; 13mm for 7" casing in 8-1/2" hole; 21mm for 5-1/2" casing in 7-7/8" hole
- k) Centralisation calculations for a vertical well must include a deviation of three degrees from vertical at casing depth, unless otherwise proven. Where the actual deviation exceeds three degrees, the actual deviation data must be used. Refer to API 10D-2.
- l) Operators must review centraliser selection and application in the *API Technical Report 10TR4 Selection of Centralisers for Primary Cementing Operations*.
- m) It is mandatory that wiper plugs be used for production casing and they are recommended for surface casing to enable plug bump and pressure test of the casing before cement cures.

2.2.3.3 Good industry practice

- a) Petroleum tenure holders should ensure proper wellbore preparation, hole cleaning and conditioning prior to the cement job. Once casing has been run to landing depth, petroleum tenure holders should circulate a minimum of one-hole volume immediately prior to commencing cementing procedures.
- b) Movement of the casing (rotation and reciprocation) should be considered where appropriate to improve drilling mud removal and promote cement placement.
- c) Cement slurry design should include testing to measure the following parameters depending on site-specific geologic conditions including:
 - i. slurry density
 - ii. thickening time (compared to proposed pumping time)
 - iii. fluid loss control
 - iv. free water
 - v. compressive strength development versus time (at representative bottom hole conditions)
 - vi. fluid compatibility (cement, source/mix water, drilling mud, spacers used)
 - vii. mechanical properties.
- d) Cement job design should include proper cement spacer design and volume to ensure the appropriate contact time during pumping.
- e) Calliper logs in production hole sections, where available, should be used to confirm cement volume requirements and standoff calculations. The level of excess cement requirements should be based on local experience.
- f) Water and cement slurry samples should be taken (periodically during each cement job) by the petroleum tenure holder's well site supervisors as an aid to monitoring cement job quality and visual confirmation of speed of cement set up. Cement samples should be maintained on site for the duration of the well.
- g) Baseline cement bond log evaluation should be considered in each new field area where confirmation of cement placement has not been demonstrated. Confirmation of cement placement should be undertaken by recording cement returns to surface together with adequate displacement pressures or pressures immediately prior to plug bump. Cement bond log evaluation should continue until repetitive success of slurry design and cement placement together with adequacy of cement bond for zonal isolation is confirmed (e.g. five wells in each new field or area of different geological conditions).
- h) Leak-off tests or formation integrity tests should be used on drill out of surface casing shoes as a potential guide to shoe integrity (i.e. good cement around the casing shoe) as well as assisting with well design for well control risk.
- i) Petroleum tenure holders should ensure all cementing operations are carried out with appropriate mixing, blending and pumping of the cement job at the wellsite. These activities should be properly supervised and recorded. This includes recording any cementing problems encountered.

2.2.4 Wellheads

2.2.4.1 Principles

The primary purpose of a wellhead is to provide the suspension point and pressure seals for casing and tubing strings that run from the bottom of any hole section to the surface PCE.

The wellhead ensures well integrity at the surface and enables the installation of PCE for containment of gas and water.

Wellheads are threaded or welded onto the first string of casing, which has been cemented in place during drilling operations, to form an integral structure of the well.

Wellhead design needs to facilitate installation of PCE.

2.2.4.2 Means of compliance

- a) Operators must monitor wellheads for leaks or emissions in accordance with the separate Code of Practice for this purpose. Visit the DNRME website to read the relevant Code of Practice prescribed in the Regulation.

2.2.4.3 Good industry practice

- a) Petroleum tenure holders should ensure that during initial wellhead installation and subsequent well intervention workovers, wellhead seal tests are conducted to test the mechanical integrity of the wellhead sealing components (including valve gates and seals) and confirm they are capable of holding against well pressure.
- b) It may be advisable in some circumstances and for certain CSG well types to ensure A and B wellhead sections are used to ensure surface integrity of the surface casing annulus (between production casing and surface casing), as an additional barrier to potential leak paths.

2.2.5 Well control equipment

2.2.5.1 Principles

Well control aims to reduce hazards when drilling a CSG well and must be considered at all times. The primary purpose of well control is to provide barriers to prevent escape of formation fluids to surface. Well control can be categorised at two levels:

- a) Primary well control – the maintenance of a hydrostatic head of fluid in the well bore, sufficient to balance the fluid pressure in the formations drilled. In practice an excess hydrostatic pressure is maintained to provide a safe level of ‘overbalance’ to formation pressure.
- b) Secondary well control – used when the primary well control fails - should there be a loss of hydrostatic pressure or a situation develops where the formation pressure exceeds the hydrostatic pressure, there is the potential for influx of formation fluids into the well. If the well begins to ‘flow’, appropriate PCE must be in place to contain any influx of formation fluids.

The requirements for well control systems will vary when underbalanced drilling techniques are employed. However, in all operations the guiding principle is to maintain at least two well control barriers in place when hydrocarbon release is possible.

2.2.5.2 Means of compliance

- a) Operators shall address well control in safety management systems. Operators shall have a well control standard document available at well sites, detailing requirements for equipment level, kick detection and well control techniques.
- b) Operators shall install PCE e.g. BOP when a reasonable potential of uncontrolled flow of well bore fluids to surface is present for all operations after the installation of the surface casing, terminating once the well is abandoned or cased and suspended once all hydrocarbon and aquifer zones are isolated.
- c) Operators shall use PCE compliant with API 16A, 16C and 16D.
- d) The level of PCE required on any operation, and the configuration employed, shall be the subject of a risk assessment and documented accordingly.
- e) Operators shall function and pressure test in line with API Standard 53, including drill through equipment, choke and kill line systems and pressure storage systems (e.g. accumulators).
- f) Operators shall utilise best industry practice for early identification of fluid influx (well kick). This shall include, but is not limited to, monitoring of mud pit level, flowline flow rate and trip volume sheets derived from trip tank measurements.
- g) To control an influx, well bore fluids shall be directed through the choke and kill manifold to circulate hazardous fluids (gas solubility) within a safe gas handling system; for example using the mud gas separator or poor-boy degasser vessel. A flare tank can be considered to manage the potential risk of fire and explosion if free gas cannot be vented to a safe area onsite. The operating limits of the system must take into account the design and operating capacities of the mud gas separator, the arrangement of the vent line, liquid seal and emergency relief/ bypass line. A well specific analysis is necessary to ensure the system capacity is compatible with the parameters of the reservoir gas and properties of the drilling fluids.
- h) Operators undertaking underbalanced activities shall ensure a well control risk assessment is conducted and control measures to counter the absence of primary well control are documented.
- i) All personnel involved in well control procedures and implementation must have appropriate industry recognised training certification to undertake their work, including, competency standards specified by the P&G Regulation.

2.2.5.3 Good industry practice

- a) Additional guidance for selection and use of well control equipment is documented in *API Standard 53 – Blowout Prevention Equipment Systems for Drilling Wells*.
- b) A gas detection system should be used on the well site to identify hydrocarbon bearing formations and potential gas influx.

2.2.6 Drilling fluids

2.2.6.1 Principles

Drilling fluids serve to lubricate the drilling assembly, remove the formation cuttings, maintain pressure control of the well and stabilise the hole being drilled. Drilling fluid is generally a mixture of water, clays or other viscosifiers, fluid loss control additives, lost circulation materials, and density control additives.

The standard drilling fluid currently used in the CSG industry is water-based. It may be either fresh water or may be based on salt brine. Potassium chloride, the principal salt component, is often used as a weighting agent and to help control swelling clays.

Losing drilling fluids down hole is undesirable as they are the primary means of controlling pressure within the well.

Underbalance techniques may be used for drilling where air, nitrogen or other underbalance 'aerated' fluids are used as a drilling medium. Operators and drilling contractors undertaking underbalanced drilling should ensure that all risk assessment, well design, operational and crew training considerations are addressed prior to and during execution of the project.

Drilling fluids and additives are regulated under the environmental authority issued under the *Environmental Protection Act 1994*, as they are classed as contaminants.

2.2.6.2 Means of compliance

- a) Drilling fluids must be selected and managed to ensure all manufactured products used during well procedures on CSG wells are in accordance with the manufacturer's recommendations and relevant MSDS.
- b) The name, type and quantity of each chemical used on each well throughout the life of the well must be recorded.

2.2.6.3 Good industry practice

- a) Drilling fluid should be a carefully monitored and controlled mixture designed to:
 - I. achieve best drilling results and ensure efficient removal of formation cuttings
 - II. control formation pressures
 - III. minimise damage to formations.
- b) Petroleum tenure holders should ensure that the drilling fluid selected is appropriate for the well design to manage any locally experienced drilling problems and the geological conditions likely to be encountered.
- c) The use of biodegradable substances in the drilling fluid is preferred.
- d) The source of water used for all well procedures (drilling, workover and stimulation) should be recorded for future well monitoring purposes.
- e) Products should be chosen, stored, and used at concentrations that minimise the risk of causing environmental harm.
- f) Personnel, including contractors, should be aware of the environmental impact and emergency spill procedures of the products and substances in use on site.
- g) Petroleum tenure holders should use established, effective drilling practices to achieve a stable, uniform and, as far as possible, in-gauge hole.

2.2.7 Evaluation, logging, testing and coring

2.2.7.1 Principles

The types of logs that are run in a CSG well are selected by geologists at the time the well is designed. Common logging tools used for evaluation of CSG wells include natural gamma ray, density, calliper, resistivity and image logs.

Logging produces valuable information on all formations logged, to accurately determine the nature and type of all strata encountered.

This information is used in optimising future well design and drilling operations as well as determination of the actual depth and thickness of all subsurface formations in the drilled hole.

Review of well logs assists in setting casing strings in the correct place to achieve well design objectives and to properly achieve the isolation requirements of the casing and cement.

Formation testing may be carried out on some wells. The formation is sampled by either drill pipe conveyed drill stem test tools or by wireline deployed test tools.

In some exploration wells, the well design may be modified to cut 'cores' of the strata encountered. This involves drilling a core of solid rock and recovering it to surface. The core is examined for geological information and any coals are tested for gas content.

Cuttings samples, core samples fluid samples and other samples from the CSG well drilling process should be collected, stored and/or distributed according to legislative and regulatory requirements.

2.2.7.2 Means of compliance

- a) Petroleum tenure holders must ensure that accurate down survey of each CSG well is carried out as required by the P&G Regulation. Such surveys may be carried out using the appropriate logging tools in vertical wells and/or while drilling (MWD) techniques in deviated wells.
- b) The Petroleum and Gas (General Provisions) Regulation 2017 requires samples of formation cuttings, cores and fluid samples to be kept.
- c) The P&G Regulation requires drilling rigs to have equipment that can recover survey or logging equipment lost down hole.
- d) If an emitting source cannot be retrieved from down hole, an approval to dispose of it must be sought from Queensland Health. The application for approval to dispose radioactive material form is available at:

www.health.qld.gov.au/radiationhealth/documents/app-dispose.pdf

2.2.7.3 Good industry practice

Where appropriate (e.g. when hole conditions and pressure regimes dictate), operators should ensure secondary well PCE is in place during logging operations. This may include such equipment as wireline lubricators or pack-offs.

2.2.8 Well integrity management

2.2.8.1 Principles

Monitoring and maintenance is required to preserve the well and its equipment in suitable condition for their useful life. Well Integrity Management Systems (WIMS) and associated documents for subsurface assets aim to ensure that wells meet operational availability objectives and well integrity goals for the full life cycle of the well.

Wells are designed to be operated such that:

- a) well barrier status is known and technical integrity risks are managed; and
- b) well safe operating envelopes are not transgressed.

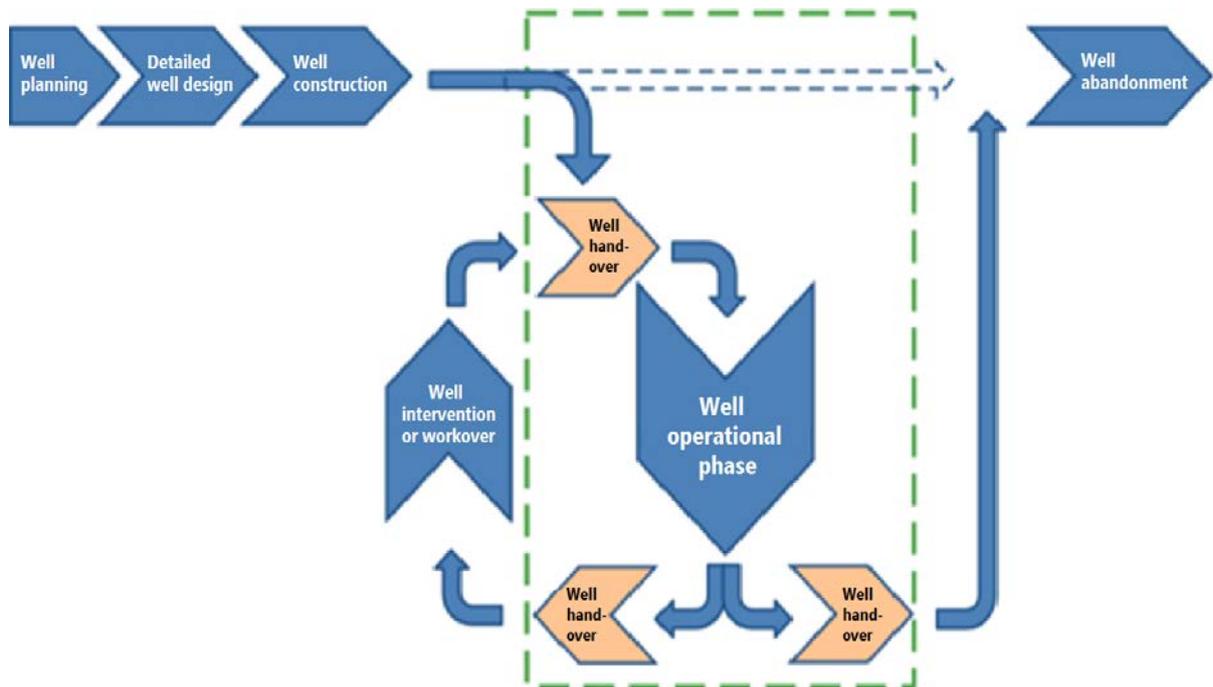


Figure 1: Illustration of the scope of this Technical Specification

(Source: ISO/TS 16530-2:2014(en): Well integrity — Part 2: Well integrity for the operational phase)

2.2.8.2 Means of compliance

- a) The petroleum tenure holder must be able to demonstrate that verification of well integrity and barriers exists through maintenance and monitoring, and through the establishment of a WIMS, or other equivalent well integrity information database. Monitoring mechanisms and their frequencies are to be determined through a risk assessment, or asset integrity management guidelines.
- b) The WIMS must outline:
 - i. a regular wellhead maintenance program
 - ii. inspections for identification of leaks, in accordance with the relevant Code of Practice
 - iii. routine operational visits
 - iv. monitoring and management of annuli pressures
 - v. barrier maintenance and verification
 - vi. assessment during the well life cycle, of the well head, tubing and casing, for any wear due to erosion or corrosion, and its impact on well integrity
 - vii. risk assessment and response levels for impaired barriers, and
 - viii. well integrity records to be maintained.
- c) The petroleum tenure holder is responsible for ensuring maintenance of current documented records, that clearly state the existing risk level of wells and any other observations related to well integrity. The records shall also contain the operational status and completion status of all wells.
- d) If a well integrity issue is discovered, a risk assessment must be completed and any identified control measures, such as well monitoring, or abatement measures, must be implemented for the well to continue operating.

2.2.8.3 Good industry practice

- a) All surface equipment associated with the well barrier envelope should have a preventative maintenance program in place.
- b) If the annulus is being abnormally charged with gas, an analysis of the gas content may assist in the determination of the source and nature of a potential leak

References:

- Code of Practice for leak management, detection and reporting for petroleum operating plant, Version 4 (DNRME, 2018)
- ISO 16530-2, Well integrity - Part 2: Well integrity for the operational phase
- NORSOK Standard D-010, Well integrity in drilling and well operations.

2.2.9 Abandonment of wells, bores and other drill holes

This section has been developed primarily for support of CSG tenure holders in the abandonment of CSG wells and bores on their tenure or water monitoring authority, however other types of drill holes may also require abandonment by the operator. For example as part of an agreement with a local landholder or other stakeholder, to reduce the risk of fugitive gas emissions, or to reduce the risk of aquifer contamination from offsetting wells or bores.

Additionally, a drill hole may require abandonment under the P&G Act as part of *incidental activity*. Where activity is undertaken on the tenure to support the production of coal seam gas, such activity may be regarded as *incidental activity*, which is subject to the regulatory and safety regime of the P&G Act.

Therefore this section can be used for abandonment of a range of different wells, bores or drill holes, depending on the requirements of the particular tenure where it is being applied.

2.2.9.1 Principles

CSG well abandonment must ensure the environmentally sound and safe isolation of the well, protection of groundwater resources, isolation of the productive formations from other formations, and the proper removal of surface equipment.

The outcomes of well abandonment are to:

- a) isolate aquifers within the well from each other and from permeable hydrocarbon zones
- b) isolate permeable hydrocarbon zones within the well from each other unless commingling is permitted
- c) ensure there is no pressure or flow of hydrocarbons or fluids at surface both internally in the well and externally behind all casing strings
- d) recover/ remove surface equipment so as to not adversely interfere with the normal activities of the owner of the land on which the well or bore is located.

The following matters must be considered prior to well abandonment:

- a) the construction characteristics of the well and well integrity status at time of abandonment including but not limited to:
 - i. sustained pressure/flow on casing annulus
 - ii. confirmation of cement tops where cement returns where not achieved
 - iii. casing integrity
 - iv. fish stuck in hole.
- b) geological formations encountered
- c) hydrogeological conditions i.e. aquifers
- d) environmental risk
- e) regulatory requirements.

2.2.9.2 Means of compliance

- a) Wells bores and other drill holes must be abandoned in accordance with this Code and all relevant legislative requirements.
- b) Any well, bore or drill hole that is to be abandoned shall be sealed and filled in such a manner to prevent leakage of gas and/or water.
- c) A horizontal well must be abandoned containing a slotted liner⁴ that is not made of steel, including for example, a slotted PVC liner.
- d) Cement shall be used as the primary sealing material. Cement testing should be carried out as per requirements set out in 2.2.3 of the Code.
- e) Prior to commencing abandonment, the Operator must confirm the absence of pressure/flow externally behind all casing strings. This requires a surface casing vent flow test to determine if hydrocarbons, liquid, or any combination of substances is escaping from the casing vent assemblies.
- f) Sucker rods, pump and tubing (unless used as a sacrificial stinger) and any other debris in the well or bore that can practicably be removed are removed.
- g) There must be a continuous cement barrier with a minimum 30 m length adjacent to the impermeable formation (cap rock) overlying the uppermost hydrocarbon zone.
- h) There must be a minimum of two adjacent cement barriers across all aquifers above the uppermost hydrocarbon production zone. This can be achieved by the following:
 - i. Having the surface casing set below the aquifer and cemented to surface and the production casing cemented from 30 m below the base of the lowermost aquifer to 30 m above the uppermost aquifer. In cases where the production zone is less than 30 m below the lowermost aquifer, casing is to be cemented from as low as practical below that aquifer.
 - ii. Fully cementing the inner most casing string from the production zone to the surface provided the cement plug(s) are adjacent to good annulus cement
 - iii. If production casing has not been cemented with an overlap inside the surface casing shoe the operator must remediate the well until the required barriers are achieved. This could involve removing the production casing above the cement top if technically and commercially feasible to do so or performing remediation cement squeezes. Cement top up jobs are not an approved method of remediation unless isolation can be confirmed with cement bond logs
- i) For pre-existing mineral exploration drill holes that are fully uncased, the openhole must be cleaned out down to TD or Hang-Up-Depth (HUD) and fully cemented to surface.
- j) Cement plugs shall not exceed 200 m in length unless installed with coil tubing or sacrificial stinger. A 50 m weighted high-vis pill must be spotted below each cement plug that is not set directly above a physical barrier.

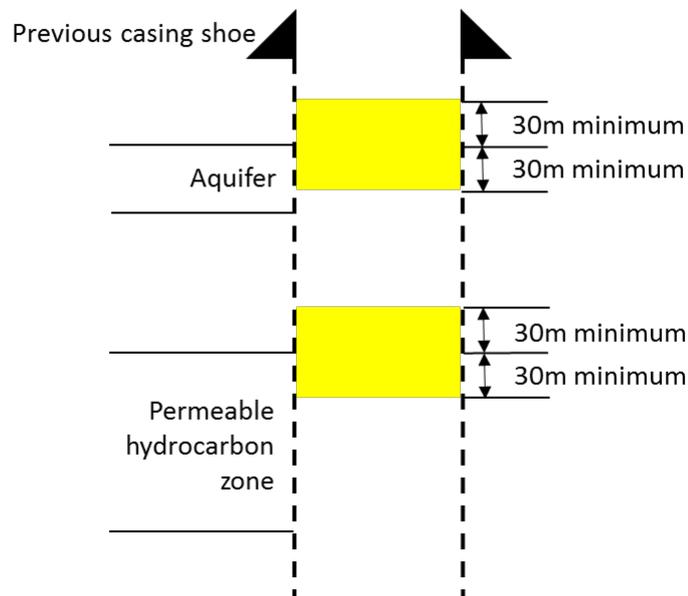
⁴ If the horizontal well has the potential to be a high risk area for future coal mining because of high levels of methane, the operator must conduct a risk assessment that includes an assessment of whether a Fire Resistant Anti Static (FRAS) liner should be used in the well.

- k) Cement plugs for decommissioning must meet the minimum requirements as detailed in the 2.2.9.2.1 of this Code and consider the following: *Abandonment plug requirements and verification methods* :
- i. The preferred method where possible is to cement inner casing string to surface.
 - ii. Consecutive stacked cement plugs set inside casing do not require additional tagging provided initial verification method is performed.
 - iii. If unable to achieve the required 1000 kg set down weight (e.g. plug is too shallow or coil tubing is used) the minimum force with which plugs must be verified is maximum string weight.
Note: that the use of slick-line or wireline is not an approved method of verifying the tops of plugs.
- l) Plugs that do not pass pressure testing must be remediated until requirements are achieved as noted below:
- i. If sufficient depth is available to meet requirements an additional cement plug may be installed and re-tested
 - ii. For failed mechanical barriers an additional mechanical barrier may be installed and re-tested
 - iii. If insufficient depth is available the plug(s) will have to be circulated or drilled out. The plug(s) must then be rerun and pressure tested.
- m) Plugs that are confirmed as too low or too high after tagging are unacceptable. The Operator must remediate until requirements are achieved as noted below.
- i. A plug is too low if it has a top less than 15 vertical meters above the zone it was intended to cover. Such a plug must be built up to required depth and its location confirmed.
 - ii. High plugs must be drilled out if the theoretical plug base is less than 15 vertical meters below the base of the zone it was intended to cover. The plug must be re-cemented and its location confirmed
- n) BOPs and/or the wellhead must not be removed until the cement plug across the surface casing shoe or plug across the uppermost perforations has been physically tagged for correct location, then pressure tested.
- o) Water-based fluid mixed with Biocide, oxygen scavenger and/or corrosion inhibitor shall be left in the wellbore above the top most cement plug and in-between cement plugs if the well is not cemented to surface.
- p) Prior to conducting a surface abandonment, the Operator must confirm the absence of pressure/flow internally within the well and externally behind all casing strings. Wells with no history of external flow/pressure may be cut and capped immediately. All other wells must be monitored for a minimum of 6 months prior to conducting surface abandonment.
- q) A surface cement plug minimum 10 m in length must be placed at the top of the casing. The surface plug acts as a barrier to prevent any long-term ingress into the wellbore and is not deemed to be a pressure containing barrier. Well barriers to be established with the plugs below the surface cement plug.
- r) Wellheads must be removed, and casing string(s) must be cut minimum 1.5 m below surface.
- s) The well must be capped below the surface across all casing strings with a steel marker plate that is fastened and installed in a manner as to prevent any potential for pressure to build up within the casings while restricting access to the casing strings at surface (vented/ported plate)

- t) The steel marker plate must be installed as per legislative requirements:
- i. the identifying name of the well or bore
 - ii. the total depth in metres of the well or bore
 - iii. the date the well or bore was abandoned.
- u) Complete and accurate records of the entire abandonment procedure must be kept, with these records submitted as part of the Well Abandonment Report once final cut and cap has been completed.

2.2.9.2.1 Abandonment plug requirements and verification methods

Figure 2: Open hole/ uncased hole section (no lost circulation and not approved for commingling)



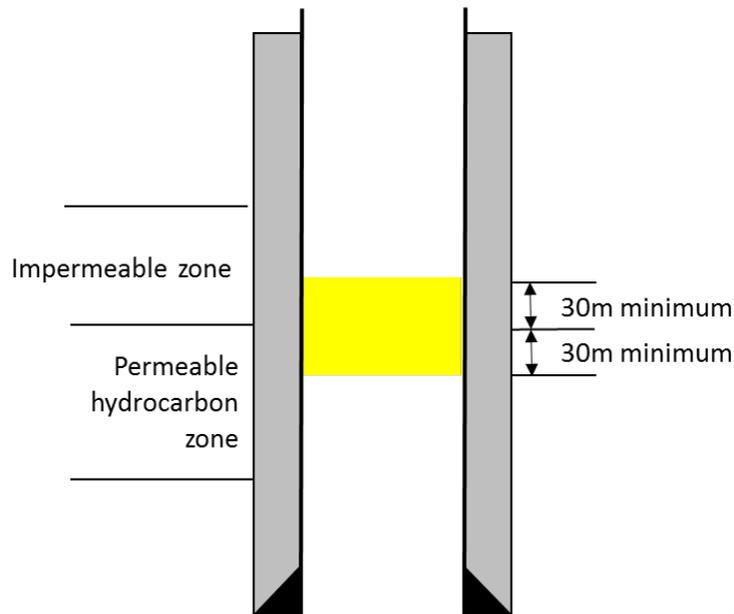
Requirement

- Cement plug(s) must be placed to provide cement coverage at least 30 m above and 30 m below the top of any permeable hydrocarbon or aquifer and between permeable zones of different pressure regimes or salinity.

Verification method

- All off bottom open hole cement plugs to be verified by tagging the plug with a minimum 1000 kg set down weight.

Figure 3: Cased hole section



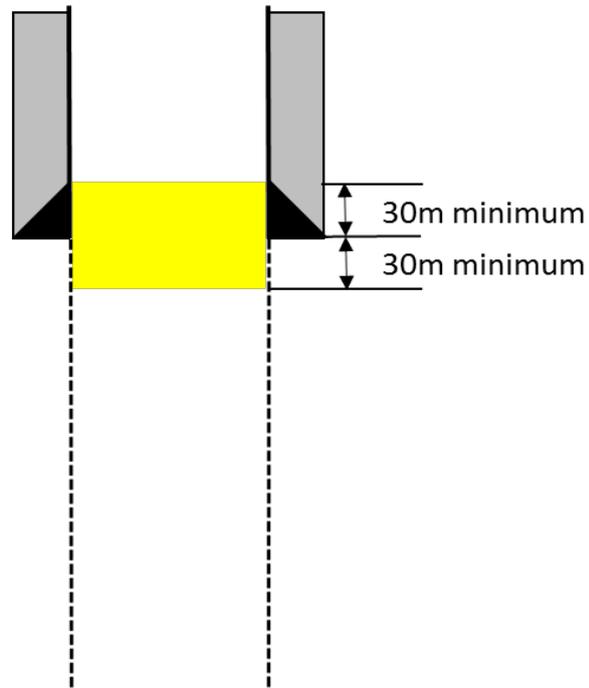
Requirement

- Verified cement plug(s) placed adjacent to good annulus cement must be placed to provide cement coverage to surface or at least 30 m overlap with the impermeable formation overlying the uppermost hydrocarbon zone.
- Verified cement plug(s) must also be placed to provide minimum 30 m coverage above aquifers unless these are already isolated by two cemented casing strings.

Verification Method

- A cement plug supported by a pressure tested mechanical barrier must be verified by tagging the mechanical barrier or top of the cement plug with a minimum 1000 kg set down weight.
- An unsupported cement plug must be verified by tagging the initial plug with a minimum 1000 kg set down weight.

Figure 4: Casing shoe with open hole below



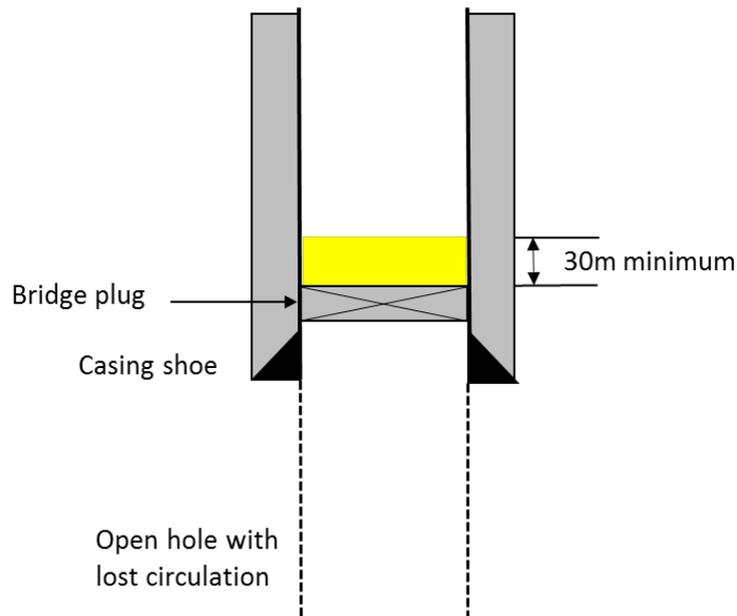
Requirement

- Verified cement plug(s) must be placed to provide cement coverage to surface or at least 30m above and 30m below the previous casing shoe.

Verification Method

- A cement plug with the bottom of the plug exposed to open hole must be verified by tagging the first plug extending above the casing shoe with a minimum 1000 kg set down weight and by pressure testing to 3.5 MPa above the estimated (or previously recorded) leak off pressure (within the limits of the casing and wellhead pressure ratings).

Figure 5: Casing shoe with open hole/un-cemented liner below (with lost circulation)



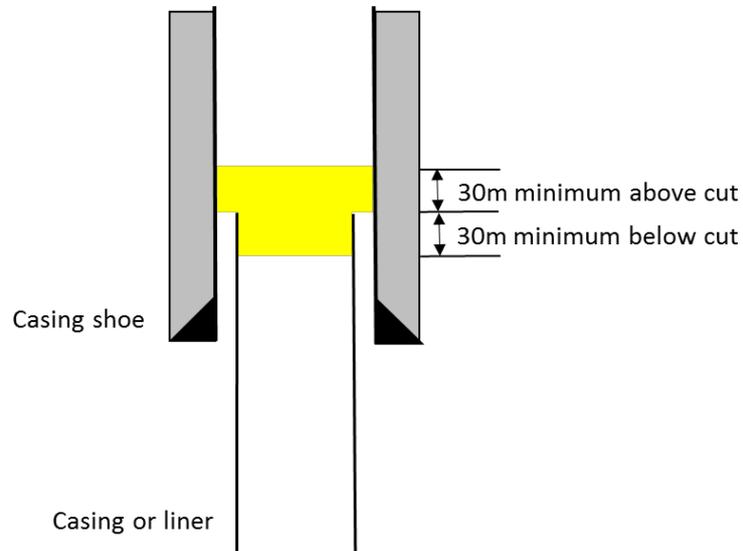
Requirement

- Where lost circulation conditions exist a mechanical barrier may be set as close as is practicable to the casing shoe with cement coverage to surface or at least 30 m above the mechanical barrier and adjacent to good annulus cement (only applicable if co-mingling is allowed).

Verification method

- A cement plug supported by a pressure tested mechanical barrier must be verified by tagging the mechanical barrier or top of the cement plug with a minimum 1000 kg set down weight.

Figure 6: Cut and recovered casing/liner or Production liner laps



Case: Cut and recovered casing/liner

Requirement

- Verified cement plug(s) must be placed to provide cement coverage 30 m below casing cut and cement to surface or at least 30 m above the casing cut.

Verification method

- Cement plug must be verified by tagging the plug with a minimum 1000 kg set down weight.

Case: Production liner laps

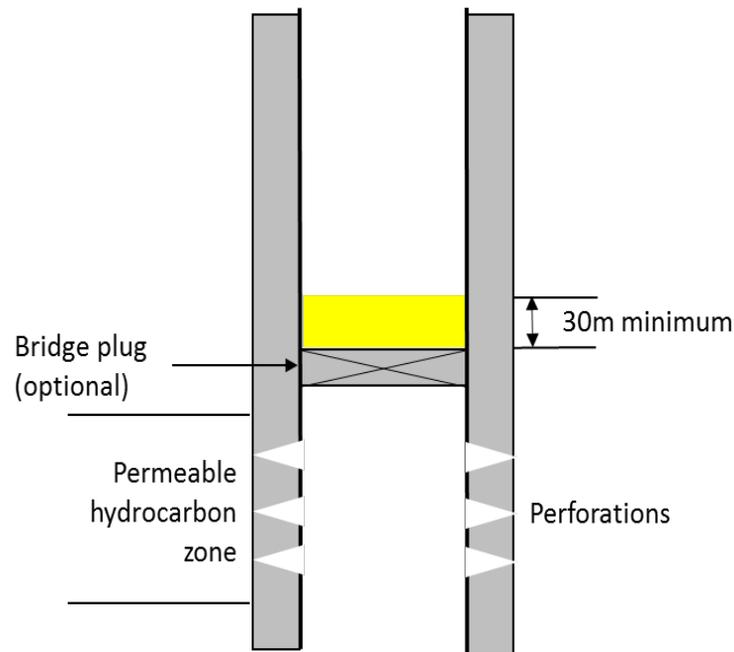
Requirement

- A cement plug barrier should be set across each Liner top in the form of a T-plug with at least 30 m of cement below and cement coverage to surface or at least 30 m of cement above liner top.

Verification method

- Cement plug must be verified by tagging the plug with a minimum 1000 kg set down weight and by pressure testing to 3.5 MPa above the estimated (or previously recorded) leak off pressure (within the limits of the casing and wellhead pressure ratings).

Figure 7: Perforated casing



Requirement

- Verified cement plugs must be placed to provide cement coverage to surface or at least 30 m above perforated intervals.
- A mechanical barrier with cement coverage to surface or at least 30 m above the mechanical plug (mechanical plug to be set as close as is practicable above perforations).
- Verified cement plug must be used to isolate perforated intervals of different pressure regimes, as per regulatory requirements. If co-mingling is allowed⁵, one plug placed above the perforated intervals is sufficient.

Verification method

- A cement plug supported by a pressure tested mechanical barrier must be verified by tagging the mechanical barrier or top of the cement of plug with a minimum 1000 kg set down weight.
- A cased hole cement plug set on bottom exposed to open perforations, verification to be done by tagging the top of the first cement plug extending above the perforations with a minimum 1000 kg set down weight and by pressure testing to 3.5 MPa above the estimated (or previously recorded) leak off pressure (within the limits of the casing and wellhead pressure ratings).

See Appendix 4 for Examples of Standard Surat Abandonment Schematics

⁵ Note: Some formations such as the Walloons coal measures or Bandanna formation are considered as a single entity and do not require zonal isolation within the formation. The regulator should be consulted about other formations.

2.2.9.3 Good industry practice

- a) Use of an integrated open-hole volume calculated from a calliper on a wireline log to calculate cement volumes where possible (this applies mostly to exploration wells which are to be plugged and abandoned).
- b) If no calliper data is available, 20–30% above theoretical volume calculated from nominal casing diameter and gauge hole size should be used, along with local hydrogeological knowledge and offset well data.
- c) Plugs should normally be a minimum of 30 m in length (height). If the hole is badly washed out, it may be better to set two short plugs over the washed out section than to try to cover this interval with one plug.
- d) After placement of a cement plug the rate to pull the work string should be controlled to avoid intermixing of the plug and other fluids in the hole.
- e) Excess cement should be used when placing plug and circulated off the top of the plug to minimise contamination issues.
- f) Work string wiper dart/balls should be used to separate cement and fluids during placement. If wiper darts are used a catcher sub should be included in the work-string.
- g) Displacement rates during cement plug placement should be kept as high as possible without exceeding the open-hole fracture gradient. This aids in the displacement of the wellbore fluids by the spacer and cement flowing up the annulus. Spacer volumes should be adjusted to provide adequate contact time based on the estimated displacement rate.
- a) The Wait on Cement (WOC) time for tagging should be based on the pre-job lab testing of the slurry at BHST, preferably on an Ultrasonic Cement Analyser (UCA). Typically the time to 500 psi compressive strength is adequate for tagging cement. If the cement plug does not take weight, it is recommended to increase WOC in 4 hours increments up to a maximum of 12 hours additional WOC time.

2.2.10 Recording and reporting data

2.2.10.1 Principles

Accurate information, on the design, drilling, construction, reconditioning, and abandonment of wells, needs to be recorded for future reference. Construction of a water bore has additional new requirements under the petroleum regulations relating to information that must be provided to the Water Act regulator, as well as information outlined under Part 4 of this Code.

2.2.10.2 Means of compliance

- a) The Petroleum and Gas (General Provisions) Regulation 2017 includes a number of well reporting requirements for daily drilling reports, well and bore completion reports and well or bore abandonment reports. It is the responsibility of the petroleum tenure holder to ensure that these reporting requirements are fulfilled.
- b) In addition, cementing reports, including all materials and compressive strength vs. time graphs, cement pump charts and pressure records, logging reports including well deviation details and details of centraliser placing must be completed and submitted with well and bore completion reports.

2.2.10.3 Good industry practice

Adequate record keeping should be carried out to verify conformity to the well design and during the construction process. A record of all work undertaken on a well should be maintained for each well's entire life through to abandoning. These records may include:

- a) engineering design basis
- b) kick tolerance/well control design assumptions
- c) BOP pressure testing requirements, and actual test records
- d) laboratory test results for cement slurries
- e) casing tallies for all casing strings run including lengths, weights, grades, inside diameter, outside diameter, setting depth
- f) cementing records for each casing string in each well
- g) casing pressure tests
- h) leak off test and/or formation integrity test reports
- i) wireline logs
- j) core description reports
- k) records of all equipment used
- l) records of mud chemicals, treatment and workover chemicals used during all well procedures (name, type and volume of each chemical used should be recorded)
- m) records of drilling and cementing problems encountered during the well
- n) risk assessments
- o) well drilling and completion programs including casing running and cementing procedures
- p) daily rig reports
- q) daily geological reports, if relevant
- r) service company reports.

3 Petroleum wells

3.1 General description of petroleum well life cycle activities

3.1.1 Introduction

This Code considers the well life cycle phases of:

- a) preliminary well planning and well design
- b) well construction (up to the production wing valve of the well head/ Christmas tree);
- c) well evaluation and hydraulic fracture stimulation activities
- d) well integrity management
- e) well suspension and abandonment
- f) construction of new water bores by petroleum tenure holders
- g) conversion of petroleum (non CSG) wells to water bores.

3.1.2 Outline of the well life cycle phases

The general steps involved in the petroleum well life cycle for exploration or production:

Preliminary well planning and well design

- a) Site identification and location
- b) Completion of environmental controls, monitoring and sampling required to fulfil the regulatory requirements
- c) Well construction design
- d) Rig requirements and identification of appropriate equipment
- e) Identification of a water source for drilling fluid(s)
- f) Approval to drill/construct a well
- g) Notification to hydraulically stimulate a well (if required).

Well construction

- a) Site/lease preparation in accordance with regulatory approvals and consent conditions
- b) Well drilling operations
- c) Running and cementing of casing
- d) Formation evaluation and/or testing
- e) Hydraulic stimulation operations (if required)
- f) Well completion operations.

Well Production / Testing

- a) Ongoing production testing, sampling and monitoring as required
- b) Any additional well stimulation if required
- c) Well monitoring as per integrity management plans
- d) Workover/intervention activities.

Well abandonment / suspension

- a) Approval to suspend
- b) Well suspension or abandonment operations at the wellsite
- c) Site rehabilitation activities.

3.1.3 Site identification and location

Wells are first planned through a desktop process to identify potential or suitable sites within known constraints such as tenement boundaries, topographic constraints, cultural heritage and environmental restrictions.

An additional desktop review is undertaken on potential exploration and appraisal well sites to identify locations which may best define the geology of an area or project. This may be based on earlier seismic surveys.

After the desktop assessment, consultation with the relevant stakeholders' takes place to select the most appropriate site, taking into consideration all other constraints (e.g. access routes). There may be flexibility in locating proposed wells to avoid particular sites and minimise potential impacts to the environment and existing land use.

Petroleum tenure holders are required by law to conduct various checks on any site where works are proposed. These checks are either office or field-based, and may include:

- a) environmental checks (e.g. distance from specific flora and fauna communities)
- b) cultural heritage inspections (particularly with regard to indigenous cultural heritage)
- c) topography restrictions and issues (avoiding water courses, ravines, steep cliff faces)
- d) confirmation lease preparations are suitable for loads of establishing a drilling rig on the location
- e) land use restrictions (including consultation with landholders)
- f) other stakeholder liaison.

Once agreement is reached on the location of a well, the primary considerations in preparing a well site are safety and the environment.

For safety of both site personnel and landholders, well sites should be sized and prepared appropriately and may also be fenced for safety and to provide a barrier to exclude livestock and large wildlife. The environmental procedures used in preparing the site may include the stockpiling of topsoil which is kept separate for rehabilitation, and minimising the footprint where possible.

In most cases ground pits (or sumps) are excavated to hold drilling or waste water. Sufficient storage for well site activities needs to be provided in these sumps, which may be lined with heavy grade plastic if required by ground conditions.

It may be necessary to dig a 'cellar' to house the lower section of the wellhead and allow sufficient clearance for the blowout preventer (BOP) to be installed. The BOP is safety-specific equipment which allows the well to be sealed at the surface in case of unplanned flow of formation fluids into the wellbore, or a build-up of pressure within the well. This serves to minimise the risk of uncontrolled release of any well fluids to the environment.

3.1.4 Risk management/risk identification

Petroleum tenure holders shall carry out risk assessments through their own risk management processes to identify the risks that may occur during well construction well integrity monitoring and abandonment activities.

Risks can be identified in a risk hazard register and developed for each well, or groups of wells of similar well design where there is no differentiation in risk.

The risk management process shall include assessment of risks and identification of control measures. Risks shall be managed to a level that is as low as is reasonably practicable.

3.1.5 Management of change

Petroleum tenure holders shall have a management of change (MOC) process covering wells throughout the full life cycle from initial design to final abandonment. The MOC process will typically require approval of changes or deviations to a Petroleum tenure holder's standards or requirements, which are documented.

3.2 Principles, means of compliance and good industry practices

This section outlines requirements for construction, converting and abandoning petroleum wells.

3.2.1 Well life cycle records, reporting and notification

3.2.1.1 Principles

Petroleum tenure holders are to maintain records associated with drilling, completion, workover and well abandonment.

Construction of a new water bore and conversion of a petroleum well to a water bore has additional requirements under the P&G Act, as well as requirements outlined under Part 4 of this Code.

3.2.1.2 Means of compliance

Under the P&G Act a number of mandatory well reporting requirements are stipulated. It is the responsibility of the petroleum tenure holder to ensure that these reporting requirements are met.

3.2.1.3 Good industry practice

Records to be maintained for each well, or group of similar wells where appropriate, may include the following:

- a) Engineering design basis
- b) Kick tolerance/well control design assumptions
- c) BOP pressure testing requirements, and actual test records
- d) Laboratory test results for cement slurries
- e) Workover/intervention records and reports
- f) Final directional survey listing
- g) Service company reports
- h) Well integrity records.

3.2.2 Well design and well barriers

3.2.2.1 Principles

The petroleum tenure holder is responsible for ensuring that a suitable well construction and integrity assurance process is in place, maintaining necessary well documentation and undertaking regular audits of the process for all wells.

Petroleum wells are designed and constructed such that:

- a) well objectives are met.
- b) well barriers are designed to prevent unintentional influx, crossflow to other formation layers and outflow to the external environment. Failure of one barrier should not lead to an uncontrolled release of formation fluids (blowout).
- c) testing and acceptance requirements specified in the well program are satisfied.
- d) wells can be monitored and maintained to contain and control wellbore fluids, provide structural support and otherwise retain well integrity throughout all reasonably anticipated construction, testing, production, injection, intervention, workover, suspension and abandonment load conditions – as may occur during the specified design life of the well.
- e) zonal isolation between different aquifers is achieved.

3.2.2.2 Means of compliance

Petroleum wells must be designed to:

- a) assess casing setting depths that take into account aquifer and production zone locations, and the requirements for well control
- b) provide for installation of BOP equipment
- c) use fit for purpose casing weight and grade including consideration of casing corrosion risk and connection suitability
- d) specify requirements for well construction materials
- e) determine casing centralisation requirements
- f) use engineered cement slurries and appropriate cement placement techniques
- g) ensure all petroleum fluids produced from the well do not crossflow to aquifers
- h) ensure they are constructed, maintained and abandoned in such a manner that it can be demonstrated there are two verified well barriers between a hydrocarbon bearing or abnormally pressured formation and the surface.

Exception from two verified barriers as stated in point (h) above is permissible in the following circumstances:

- a) when it has been demonstrated, via risk assessment, that there is no natural lift mechanism for hydrocarbons or water to flow to the surface
- b) during top hole or surface hole drilling where shallow gas risk has been assessed as being negligible
- c) during diverter drilling
- d) during planned underbalanced and managed pressure drilling where surface equipment design limits are not exceeded

- e) during well abandonment when two overlying formations need to be isolated from one another and two barriers are not feasible, then a continuous cement plug extending minimum 30m above to 30m below the interface must be placed instead
- f) in other circumstances during well life cycle activities when a risk assessment has been completed as per the Petroleum tenure holder's risk management process.

3.2.2.3 Good industry practice

- a) Review offset well information to assist in the design process for new wells.
- b) Review information on geological strata and formations, and fluids within them, that the well may intersect and any hazards which such strata and formations may contain.
- c) Note formation horizons or zones, from which water bores produce, during the offset well review to assist the placement of casing strings.
- d) Select casing hardware, including liner hangers, float equipment, centralisers, cement baskets, wiper plugs, stage tools and external casing packers, as appropriate as part of the well design to achieve zonal isolation.
- e) Schematic drawings of well barrier arrangements should be prepared for the well or group of wells of similar well design and architecture.
- f) A barrier should only be considered verified when there is physical evidence (e.g. leak testing by application of differential pressure, cement integrity test for cement around casing shoe, function testing) that the barrier has been placed in its desired location and will perform its required function.
- g) The test pressures for verifying well barriers should be applied in the direction of flow towards the external environment. If this is not possible or introduces additional risk, the test pressure can be applied against the direction of flow towards the external environment, provided the well barrier is designed to seal in both flow directions.
- h) A barrier placement and verification procedure should be developed to identify satisfactory establishment of barriers at each relevant stage of well operations during well construction.
- i) The qualified personnel (individual, team, department, or other company) undertaking the well construction process should be sufficiently independent from the immediate line management of the work being examined and that he/she/they does not have responsibility for undertaking the design and construction of the well.

References:

- API Guidance Document HF1, Hydraulic Fracturing Operations— Well Construction and Integrity Guidelines
- API Standard 53, Blowout Prevention Equipment Systems for Drilling Operations.
- API Standard 65-2, Isolating Potential Flow Zones During Well Construction
- ISO 16530-2, Well integrity - Part 2: Well integrity for the operational phase
- NORSOK Standard D-010, Well integrity in drilling and well operations – latest edition.

3.2.3 High pressure high temperature petroleum well design

3.2.3.1 Principles

For High Pressure High Temperature (HPHT) wells (which would generally mean ≥ 149 °C (300 °F) undisturbed bottom hole static temperature; ≥ 69 MPa, or 10,000 psi, surface pressure), a greater awareness of maximum anticipated surface pressures, circulating temperatures, and well control equipment capabilities and readiness should be adhered to.

The key principles for HPHT petroleum well design involve:

- a) accurate determination of pressure, temperature, and reservoir fluid characteristics
- b) modelling to predict temperatures and pressures during well construction and the well life cycle phases
- c) identify fit for purpose rig requirements and drill string, downhole tools, well control equipment
- d) establishment of specific procedures for drilling, tripping and well control to address high temperature/pressure zones in well
- e) contingency planning for well control.

3.2.3.2 Means of compliance

- a) For HPHT wells (both ≥ 149 °C (300 °F) and ≥ 69 MPa (10,000 psi) surface pressure), a pore pressure and fracture gradient (PPFG) plot must be developed and included in all well programs.
- b) A risk assessment must be carried out on HPHT wells by the petroleum tenure holder to understand level of pore pressure and fracture gradient (PPFG) monitoring and connection fingerprinting required while drilling. Consideration should be given to real time pore pressure prediction while drilling.
- c) Wells must be designed and operated to prevent the possibility of a temperature rise causing trapped fluid, generating a pressure in excess of the equipment rating.
- d) Industry recognised software must be used for casing design in HPHT wells and where hydraulic fracture stimulation surface treating pressures exceed 69 MPa (10,000 psi). This is to confirm that temperature effects and resultant compression forces in particular are adequately assessed in the casing and tubing design.
- e) For high temperature wells the impact of temperature on fluid properties, affecting its ability to perform as a well barrier must be reviewed.
- f) Rig selection and capability for HPHT operations must satisfy the well construction requirements.
- g) Advanced well control response and equipment must be considered as part of the well design for tertiary well control response.
- h) Specific training for HPHT well control response must be as per the P&G Act and Regulations.

3.2.3.3 Good industry practice

- a) In areas where Pore Pressure Fracture Gradient (PPFG) cannot be determined accurately through the review of offset data, pore pressure prediction studies based on seismic data and/or other specialist techniques may be used.
- b) In high temperature wells (≥ 149 °C or 300 °F) the wellbore temperature can vary significantly between a static (geothermal) condition and the dynamic, or circulating, condition of the mud system. Temperatures measured while drilling and logging should be taken into account to help optimise mud properties, cementing fluid properties and design.

- c) When drilling with a weighted fluid, the density in/out of the well should be checked at an appropriate frequency to confirm the correct weight is being maintained to control the well. On HPHT wells the fluid should be weighed at a higher frequency than other wells, as determined by the Petroleum tenure holder. Modelling of the equivalent static density and equivalent circulating densities should be conducted where accurate control of mud weight is required (e.g. small overbalance scenarios).
- d) Bottom hole assembly (BHA) components should be rated for the anticipated temperature and pressure in the appropriate hole section(s):
 - i. Consideration should be given to use of both a drilling float valve and a drop in dart sub in the drill string. Consideration should be given to two drop in dart subs in tapered drill strings. Drilling float valves may be ported following a risk assessment.
 - ii. Consideration should be given to using a drilling stand to facilitate installation of a kill assembly for high pressure pumping that may be needed during a well killing operation when drilling in abnormally pressured hydrocarbon bearing zones with potential to flow.
- e) Consideration should be given to the working temperature rating for well control equipment, which should meet the maximum anticipated continuous exposure temperature for rubber/elastomer components and high pressure hoses. Critical spares should include components exposed to high temperatures while drilling.

References:

- Energy Institute Part 17: Volume 1: High Pressure and High Temperature (HPHT) Well Planning (2009). Model Code of Safe Practice in the Petroleum Industry.

3.2.4 Working with hydrogen sulphide (H₂S)

3.2.4.1 Principles

Hydrogen sulphide (H₂S) is classed as a hazardous substance and a dangerous good. H₂S is a colourless, highly flammable gas (explosive range 4.5 - 45% gas in air) with a rotten egg odour at low concentrations, and burns in air with a blue flame. H₂S has no odour above 200 ppm due to olfactory fatigue and then gives little warning of exposure. It is denser than air and can have a prolonged presence in poorly ventilated spaces, at ground level or in confined spaces. The gas is highly toxic if exposure is prolonged, even at low concentrations. Lethal H₂S toxicity following inhalation of 600 – 2000 ppm in air paralyses the respiratory centre and causes breathing to stop.

H₂S is sometimes found in fluids encountered in oil and gas producing and gas processing operations. To prevent H₂S entering the wellbore, it is recommended to drill a formation with H₂S with over-balanced drilling fluid. However, some H₂S would still be present in the drilled gas. In addition Sulphur Dioxide (SO₂) may be present; SO₂ is a toxic product of combustion of H₂S and is normally heavier than air.

The means of compliance and good industry practices cover any well location where H₂S is expected to exceed 10 ppm (by volume) in the breathing zone.

Detailed information including the effects of exposure to H₂S and associated first-aid response can be found in the Material Safety Data Sheet (MSDS) for H₂S⁶ and API RP49, Recommended Practices For Safe Drilling of Wells Containing H₂S.

⁶ National Pollutant Inventory: Hydrogen Sulphide: <http://www.npi.gov.au/resource/hydrogen-sulfide>

3.2.4.2 Means of compliance

- a) On exploration or appraisal wells, or where there has been regional evidence of H₂S, a review of reservoir and offset well data must be carried out for a well, or campaign of wells in the same reservoir, to determine the probability and concentration levels of H₂S.
- b) As hydrogen sulphide is classed as a hazardous substance a risk assessment must be conducted and recorded for all work activities where personnel may be exposed to the substance.
- c) Prior to operations in an H₂S environment, an H₂S management plan must be developed. Refer to API RP49, Recommended Practices For Safe Drilling Of Wells Containing H₂S.
- d) The petroleum tenure holder must advise the drilling contractor and service companies involved in well site operations of predicted H₂S levels and temperatures.
- e) A flare system must be provided to safely collect and burn H₂S gas during well control or well test operations. Flare lines must be located as far away from the well as reasonably practical.
- f) For operations where H₂S is predicted, continuous H₂S monitoring equipment shall be installed, which is capable of continuously measuring and displaying the concentration of H₂S in ambient air. H₂S gas detectors must be available for personnel working in a known high risk zone when H₂S is present or predicted in any quantity. H₂S alarm setting of 5 ppm must be used for personal, portable and fixed detectors.
- g) Personnel protection must be provided if the work area concentration of hydrogen sulphide are expected to exceed or are found to exceed 10 ppm 8-hour time weighted average (TWA) or 15 ppm as a short term exposure level (STEL) averaged over 15 minutes. Personnel safety provisions do not apply when the atmospheric concentration of hydrogen sulphide could not exceed 10 ppm (by volume) in the breathing zone.
- h) For H₂S operations, equipment and materials shall be selected on the basis of resistance to sulphide stress cracking (SSC) and corrosion where the partial pressure of H₂S gas exceeds 0.05psi, or 10psia (psi in air) in sour crude systems. Refer to NACE Standard MR0175/ ISO 15156 for recommendations for selection of equipment and materials for sour conditions.
- i) Elastomers, packing and other non-ferrous parts exposed to H₂S must be resistant at the maximum anticipated temperature of exposure.
- j) A drilling fluid program must cater for the use of an H₂S scavenger to remove any H₂S from the drilling fluid.
- k) When coring operations are conducted in possible H₂S bearing zones, the wearing of breathing equipment and testing for H₂S using hand held sensors must be used for the final 10 stands, and must continue while retrieving the inner core barrels, opening the core barrels and examining the cores. Prior to transportation, cores must be sealed and marked to indicate the presence of H₂S.
- l) If H₂S in the gas phase is predicted during well test operations, H₂S concentration must be monitored at first hydrocarbons to surface and at regular intervals throughout the test.
- m) If H₂S levels exceed original design assumptions or cannot be controlled by the resources available on the rig, then the well must be shut-in. The well must remain shut in until such a time as the level of H₂S readiness is increased such that operations can continue safely.

3.2.4.3 Good industry practice

- a) H₂S sensors that activate and provide audible and visual alarms when sensing 5 ppm of H₂S in the atmosphere should be installed and be confirmed functioning.
- b) All fixed and portable detectors should be function tested weekly in accordance with manufacturer's specifications.
- c) H₂S is detected in muds using methods such as the Garrett Gas Train (GGT) method or the Hach test. The GGT will give a quantitative result and is more accurate. Tests provide useful information to help decide scavenger treatment levels. Removal of the hydrogen sulphide or its resulting sulphide anion from drilling mud requires its precipitation as an insoluble salt. The addition of zinc carbonate (ZnCO₃) to drilling mud will form insoluble zinc sulphide.
- d) Prior to penetrating known or predicted H₂S zones, all rig H₂S detectors should be confirmed to be functioning correctly and tested. Mud should be confirmed to be within specification, especially with respect to pH for water based muds, Pom alkalinity >2 for non-aqueous muds. Testing frequency for H₂S should be confirmed by the Petroleum tenure holder.
- e) Flaring and well testing should take place only when the wind strength and direction is sufficiently favourable to carry all released gas from the gas flare, oil burner, or otherwise, away from the installation.
- f) Sampling for H₂S should be conducted where safe and practical, and data used for optimisation of future well designs and surface facilities.

References:

- API Recommended Practice 49, Recommended Practices For Safe Drilling Of Wells Containing H₂S.
- API Recommended Practice 54, Occupational Safety for Oil and Gas Well Drilling and Servicing Operations
- NACE MR0175/ISO 15156-1, 2 and 3, Petroleum and natural gas industries – Materials for use in H₂S-containing environments in oil and gas production
- NOHSC: 1003 1995, Adopted National Exposure Standards for Atmospheric Contaminants in the Occupational Environment

3.2.5 Casing and tubing

3.2.5.1 Principles

The casing programme should be configured to accommodate all identified sub-surface hazards and to minimise risk either from cross-flow between formations or the uncontrolled release of well bore fluids to surface, throughout the life of the well.

Casing setting depths should be selected to provide an adequate safety margin between the formation fracture pressure and anticipated pressures during well control and casing cementation operations.

3.2.5.2 Means of compliance

- a) Casing and tubing stress analysis must be carried out on all reasonably foreseeable load scenarios that may be imposed on the well. Working stress design must consider both uniaxial and triaxial analysis.
- b) Casing, casing connections, wellheads, and valves used in petroleum wells must be designed to withstand the loads, pressures and temperatures that may act on them throughout the entire well life cycle. This includes casing running and cementing, any treatment pressures (e.g. hydraulic stimulation), production pressures, potential well control situations, any potential corrosive conditions (H₂S, CO₂, etc.), and other factors pertinent to local experience and operational conditions. In all petroleum wells, a conductor pipe does not need to meet the above requirements.
- c) Methods of preventing external corrosion that impact well integrity must be applied.
- d) All casing and tubing must be manufactured to the latest edition of ISO 11960. The rated capacity of the pipe body and connections must be obtained from the latest edition of ISO 11960 or the manufacturer's technical specifications.
- e) Welded joints are permitted in construction of petroleum wells provided they are manufactured in compliance with ISO 11960 Sections 6, 7 and 13, and Tables C.4 / E.4.
- f) The yield stress of the Oil Country Tubing Goods (OCTG) must be de-rated for temperature.
- g) When designing casing strings and casing connections for petroleum wells, petroleum tenure holders must design each well, or similar wells, and the casing string using appropriate design safety factors. A generic worst case design and stress analysis may be adopted to cover multiple wells in a field development targeting the same/similar reservoir.
- h) Surface casing shall be set no shallower than 60 m total vertical depth (TVD)
To verify casing integrity during the well construction process, casing must be pressure tested prior to drilling out for the next hole section (in the case of surface or intermediate casing), and prior to stimulation or completion operations commencing (in the case of production casing).

3.2.5.3 Good industry practice

- a) Typical design factors used in the hydrocarbon industry to be used in 3.2.5.2 (g) above are as per Table 1.

Table 1: Typical design factors used in the hydrocarbon industry

Pipe body	Design factor	Connection	Design factor
Triaxial	1.25	Burst/Leak	1.10
Burst	1.10	Axial tension	1.30
Collapse	1.00	Axial collapse	1.30
Axial tension	1.30	N/A	N/A
Burst	1.30	N/A	N/A

- b) Casing design should be carried out with the aid of industry recognised software, where appropriate, to confirm that temperature effects and flow back induced compression forces in particular are adequately assessed in the casing and tubing design.

- c) Pressure tests to verify casing integrity should:
 - i. Be 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.
 - ii. Be equal to the maximum annulus pressure utilised for pressure testing of completion strings/tools for the particular string and maximum surface treatment pressures for hydraulic fracture stimulation.
 - iii. Not exceed the casing design factor for the pressure test load.
 - iv. Not exceed the rated capacity of the weakest component of the casing string.
 - v. Not exceed the rated burst capacity of the casing with a safety factor applied. A typical safety factor is 70 to 80% of rated burst capacity to verify well integrity during the well construction process.
- d) Casing connection qualification testing should be to ISO 13679 Connection Application Level (CAL) II or CAL IV, based on the intended service.
- e) Compression rating of connections should be applied to casing and tubing design as per the manufacturer's recommended values.
- f) Where appropriate, suitable allowance should be made for life cycle casing wear, erosion and corrosion. Casing wear should be monitored closely in high angle wells during well construction, as well as during the well life cycle.
- g) Consideration for use of metal-to-metal seal thread connections should be given to production casing and tubing strings for wells designed for gas lift, and gas wells that cross hydrocarbon bearing or over pressured water zones.
- h) The correct use of casing dope, appropriate temperature application, and its impact on torque make-up should be incorporated into casing running procedures.
- i) Petroleum tenure holders should consider the potential impact of high casing pressure on cement bond quality when determining pressures for any casing tests carried out before cement has properly set.

References:

- API Recommended Practice 5A3/ISO 13678, Recommended Practice on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements.
- API Recommended Practice 5A5/ISO 15463, Field Inspection of New Casing, Tubing, and Plain-end Drill Pipe
- API Recommended Practice 5B1, Gauging and Inspection of Casing, tubing and Line Pipe Threads
- API Recommended Practice 5C1, Recommended Practice for Care and Use of Casing and Tubing
- API Recommended Practice 5C5/ISO 13679, Recommended Practice on Procedures for Testing Casing and Tubing Connections
- API Recommended Practice 5C6, Welding Connections to Pipe
- API Spec 8A / 8C, Grinding of welds (to suit casing elevators)
- API Specification 5B, Specification for Threading, Gauging, and Thread Inspection of Casing, Tubing, and Line Pipe Threads
- API Specification 5CT/ISO 11960, Specification for Casing and Tubing

- API Technical Report 5C3, Technical Report on Equations and Calculations for Casing, Tubing, and Line Pipe used as Casing or Tubing; and Performance Properties Tables for Casing and Tubing
- AS1666 Part 1 (1995), Slings used in bundling OCTG
- NACE MR0175/ISO 15156-1, 2 and 3, Petroleum and natural gas industries – Materials for use in H₂S-containing environments in oil and gas production.

3.2.6 Primary cementing

3.2.6.1 Principles

Primary cementation of casings and/or liner strings is designed to:

- Provide axial support for the casing string to permit further drilling and to provide an anchor for BOP equipment
- Reduce possibilities of casing buckling and/or collapse, particularly in situations where abnormal formation stresses occur
- Provide a seal across permeable and impermeable formations to prevent undesired flow of formation fluids and crossflow behind casing/liner
- Provide a seal to protect aquifers from contamination
- Seal off the bottom of the casing in order to control pressure
- Provide corrosion protection. Corrosion rates of steel with an adequate cement coating are sufficiently low that cement encapsulation of steel is accepted as a permanent barrier.

3.2.6.2 Means of compliance

- Primary cement constituents and properties must be suitable for the intended conditions of use and used in compliance with the relevant MSDS requirements.
- Appropriate cement laboratory testing procedures must be carried out (as per ISO 10426-2, API RP 10B-2 - Recommended Practice for Testing Well Cements) on representative samples of the mix water, cement and additives to confirm the resulting primary cement slurry meets the requirements of the well design (refer Table 2).
 - In the case where a number of similar wells are drilled in an area with similar well properties (depths, temperatures, and well design), constant cement materials and mix water properties, then a representative lab test may suffice.
 - The testing, as a minimum, must include slurry density, rheology, thickening time, free water, fluid loss (if required), and compressive strength development with time.

Table 2: Property and primary cement criteria

Property	Primary cement criteria
Density	<ul style="list-style-type: none"> • Designed to maintain well control, prevent gas channelling and achieve the required compressive strength yet avoid losses during cement placement.
Planned Top of Cement (TOC)	<ul style="list-style-type: none"> • Top of cement to comply with Barrier requirements set out in 3.2.2.2 of this Code. • On high temperature wells TOC must be designed to mitigate against wellhead growth due to temperature during flow back and production • Surface casing TOC must be designed to surface. • The TOC for intermediate and production casing strings must be placed at least 100 ft. (30 m) measured depth above the top most permeable hydrocarbon zone or aquifer. • The required compressive strength slurry for fracture stimulation must be placed up to at least 500ft (150m) measured depth above any zone to be hydraulically fractured. • Cement to surface must be planned for any future water bore conversion to comply with the <i>Water Act 2000</i>.

- c) A minimum 500 psi (3.44 MPa) compressive strength on the tail cement should be achieved prior to pressure testing of casing (unless conducting a green cement pressure test on bump) or drilling out the shoe track for a subsequent hole section.
- d) Casing centralisation requirements:
 - i. Casing centralisation simulation must be undertaken for the casing centralisation plan to achieve a minimum of 70% standoff across aquifers and permeable hydrocarbon bearing formations.
- e) Wiper plugs shall be used for production casing to prevent contamination of cement, and to enable plug bump and pressure test of the casing before cement cures.
- f) The petroleum tenure holder must have a verification procedure for primary cement jobs and must utilise at least one of the verification methods described in Table 4. If the petroleum tenure holder cannot verify zonal isolation is achieved through primary cementing, the petroleum tenure holder must inform the Chief Inspector as per 3.1.2 of this Code.
- g) Wait on cement time prior to slacking off or removing BOPs should be based on the cement achieving a minimum of 100 psi (0.7 MPa) compressive strength at the temperature of any potential flow zone in the annulus just cemented. Alternatively, petroleum tenure holders may use an annulus pack-off or mechanical barrier that is compliant with API Standard 65-2 and tested to verify a pressure seal prior to removing BOPs.
- h) Calcium chloride or other chloride-based accelerants must not be added to the cement mix unless the free water content of the cement is specified as <2%.

3.2.6.3 Good industry practice

- a) Petroleum tenure holders should ensure proper wellbore preparation, hole cleaning and conditioning prior to the primary cement job.
- b) Petroleum tenure holders should review centraliser selection and application in the API Technical Report 10TR4 Selection of Centralizers for Primary Cementing Operations.
- c) Movement of the casing (rotation and reciprocation) should be considered where appropriate to improve drilling mud removal and promote cement placement.
- d) Cement job design should include proper cement spacer design and volume to achieve the appropriate contact time during pumping. Where a viscosified non-newtonian spacer is used the rheology should be formulated to optimise drilling fluid removal ahead of the cement slurry.
- e) Wiper plugs are recommended for surface and intermediate casings to prevent contamination of cement and to enable plug bump and pressure test of the casing before cement cures.
- f) Calliper logs, where available, may be used to confirm cement volume requirements. The level of excess cement requirements should be based on local field knowledge.
- g) Primary cementing slurry design considerations should include those outlined in Table 3.

Table 3: Primary cementing slurry design considerations

Slurry Property	Consideration
Fluid loss	Should be controlled to maintain cement slurry properties during placement (e.g. avoid dehydration and premature thickening, less efficient mud displacement and possible losses to permeable formations).
Free water	Free water in cement slurries should be limited to avoid weak set cement and formation of gas migration channels.
Compressive strength	Both the thickening time and increase in compressive strength should be measured from the consistometer and UCA (Ultrasonic Compressive Strength Analysis) tests on the cement (at representative bottom hole conditions).

- h) Water and cement slurry samples should be taken (periodically during each cement job) by the petroleum tenure holder and cementing contractor as an aid to monitoring cement job quality and visual confirmation of thickening time of cement. Cement samples should be kept for the duration of the well.
- i) Verification and evaluation recommendations for primary cement jobs are outlined in Table 4.

Table 4: Verification and evaluation recommendations for primary cement jobs

Job Type	Verification Criteria	Contingency
Casing cementation	<ul style="list-style-type: none"> • Slurry mixed and placed in accordance with contractor approved cementation procedures. • Shoe track volume not over displaced when displacing cement slurry. • Downhole losses not greater than the excess pumped within the cement procedure, and calculated TOC using final circulating pressure (FCP) and measured fluid returns achieves the objective(s) identified within the cementation program. • No significant losses or slumping post-placement of cement. • Casing successfully pressure tested. • If drilling out casing, a cement Integrity test (CIT) satisfactory after drilling out shoe track. • Cement evaluation log prior to fracture stimulation (HPHT and gas wells). 	<ul style="list-style-type: none"> • Where the verification is inconclusive, the extension of good quality cement above the shoe, above hydrocarbons or aquifers should be verified by appropriate cement evaluation tools, interpreted by a competent person. • Remedial/top-up job cementing as required.
Liner cementation	<ul style="list-style-type: none"> • Slurry mixed and placed in accordance with contractor approved cementation procedures. • Shoe track volume not over displaced when displacing cement slurry. • Downhole losses not greater than the excess pumped within the cement procedure, and calculated TOC using final circulating pressure (FCP) and measured fluid returns achieves the objective(s) identified within the cementation program. • No significant losses or slumping post-placement of cement. • Casing successfully pressure tested. • Pressure test of liner top packer should be performed and recorded to verify zonal isolation has occurred after all the cement has reached a compressive strength of 500 psi. Testing pressures should be no less than 500 psi over the previous casing leak off test at the shoe. • If drilling out casing, cement Integrity test (CIT) satisfactory after drilling out shoe track. • Cement evaluation log prior to fracture stimulation (HPHT and gas wells). 	<ul style="list-style-type: none"> • Where the verification is inconclusive, the extension of good quality cement above the shoe, above hydrocarbons or above aquifers should be verified by appropriate cement evaluation tools, interpreted by a competent person. • If failed pressure test on bump, set liner top packer, circulate out excess cement and WOC prior to conducting pressure test again. • If failure again, may opt to run a liner tie back packer on top of the liner top and re-test. • Remedial cementing if necessary.

- j) Baseline cement bond log evaluation should be considered on production casing and liners in each new field area where confirmation of cement placement has not been demonstrated. Confirmation of cement placement should be undertaken by cement returns to surface and adequate displacement pressures or pressures immediately prior to plug bump.
- k) For high temperature wells, best practice is to confirm geothermal temperature has been calibrated from circulating temperatures measured while drilling the well. If necessary, the wellbore should be cooled with adequate circulation prior to commencing cementing operations to minimise chance of thickening time variability from tested cement formulation values.

- l) For high temperature wells, high temperature blend (with silica) slurries should be considered for all cement slurries, particularly where cementing to surface to mitigate wellhead growth. Hot wells may have high flowing wellhead temperatures that can lead to strength retrogression of cement near surface.

References:

- API Recommended Practice 10B-2/ISO10426-2, Recommended Practice for Testing Well Cements
- API Recommended Practice 10B-4, Recommended Practice on Preparation and Testing of Foamed Cement Slurries at Atmospheric Pressure
- API Recommended Practice 10B-5/ISO 10426-5, Recommended Practice on Determination of Shrinkage and Expansion of Well Cement Formulations at Atmospheric Pressure
- API Recommended Practice 10B-6/ISO 10426-6, Methods of determining the static gel strength of cement formulations
- API Recommended Practice 10D-2/ISO 10427-2, Recommended Practice for Centralizer Placement and Stop Collar Testing
- API Recommended Practice 10F/ISO 10427-3, Recommended Practice for Performance Testing of Cementing Float Equipment
- API Specification 10A/ISO 10426-1, Specification for Cements and Materials for Well Cementing
- API Specification 10D/ISO 10427-1, Specification for Bow-Spring Casing Centralizers
- API Standard 65-2 Isolating Potential Flow Zones during Well Construction
- API Technical Report 10TR1 Cement Sheath Evaluation
- API Technical Report 10TR2, Shrinkage and Expansion in Oilwell Cements
- API Technical Report 10TR3, Temperatures for API Cement Operating Thickening Time Tests
- API Technical Report 10TR4, Technical Report on Selection of Centralizers for Primary Cementing Operations
- API Technical Report 10TR5, Technical Report on Methods for Testing of Solid and Rigid Centralizers.

3.2.7 Aquifer isolation

3.2.7.1 Principles

Protection of aquifers is an integral consideration in petroleum well design.

3.2.7.2 Means of compliance

- a) Aquifers must be considered during the well design process and petroleum tenure holders must include the design of aquifer isolation in the well program.
- b) Tenure holders must ensure casing setting depth is selected to protect resources such as aquifer systems as per 3.2.5.2 of this Code.
- c) Tenure holders must ensure primary cementing design and verification is carried out as per 3.2.6.2 of this Code.
- d) Top of cement to comply with well barrier requirements set out in 3.2.2.2 and 3.2.6.2 of this Code.
- e) Monitoring of barriers and casing condition must be carried out as per the petroleum tenure holder's well integrity management plan (as per 3.2.13.2 of this Code)
- f) For wells in the Great Artesian Basin (GAB), all aquifer units, as identified in the GAB Water Resource Plan must be isolated from each other and any permeable hydrocarbon bearing zones by primary cementing. The GAB Water Resource Plan clearly identifies formations designated as aquifers for management previous casing shoe. Refer to website address:
www.legislation.qld.gov.au/LEGISLTN/CURRENT/W/WaterReGABP06.pdf
- g) For wells in the Cooper / Eromanga basin in Queensland, all aquifer units, as identified by the South Australia Cooper Basin Statement of Environmental Objectives (SEO): Drilling, Completions and Well Operations must be isolated from each other and permeable hydrocarbon bearing zones by primary cementing. The SEO clearly identifies formations designated as aquifers for management.
- h) For all other wells, all aquifer units must be isolated from each other and any permeable hydrocarbon by primary cementing.
- i) For areas not covered by the GAB or Cooper Basin requirements where potential new aquifers have been identified, information shall be brought to the attention of the Chief Inspector.

3.2.7.3 Good industry practice

Petroleum tenure holders should refer to API Standard 65-2, Isolating Potential Flow Zones during Well Construction.

References:

- API Guidance Document HF1, Hydraulic Fracturing Operations— Well Construction and Integrity Guidelines
- API Standard 65-2, Isolating Potential Flow Zones during Well Construction
- ISO 16530-2, Well integrity - Part 2: Well integrity for the operational phase
- NORSOK Standard D-010, Well integrity in drilling and well operations – latest edition.

3.2.8 Wellheads

3.2.8.1 Principles

The wellhead is a part of the defined *safe operating envelope* for the duration of the well life. It performs the general functions of:

- a) supporting casing and completion tubing strings
- b) supporting the BOP during the drilling phase, and the wellhead Christmas tree during the production phase
- c) providing the arrangement for sealing, testing, monitoring, injecting into, and bleeding off between annuli.

3.2.8.2 Means of compliance

- a) Wellhead equipment and running tools must be specified in accordance with API Spec 6A/ISO 10423 and NACE MR0175/ISO 15156.
- b) Wellhead and production tree pressure ratings must exceed all reasonably expected loads for the entire life of the well. Wellhead product specification level (PSL) and trim must be matched to the fluid properties, pressure and temperature of flowing conditions.
- c) Side outlet valves must be rated to the same pressure as the wellhead unit they are attached to. Moreover, all components on the hanger and Christmas tree and valves must be rated to the well pressure envelope.
- d) Wellheads for high temperature wells must include design for lock down of hangers, rated for the well conditions.
- e) Casing to wellhead pressure tests ('P' seal area or equivalent) must not exceed 80% of the collapse rating of the casing.
- f) Any change of usage of a wellhead (i.e. to incorporate gas lift or re-injection) must be fully risk assessed by the Petroleum tenure holder to ensure the compatibility of the existing equipment with the proposed usage.

3.2.8.3 Good industry practice

- a) Petroleum tenure holders should ensure that during initial wellhead installation, and periodic integrity testing, wellhead seal tests are conducted to test the mechanical integrity of the wellhead sealing components (including valve gates and seals) and confirm they are capable of holding against well pressure.
- b) Wellheads should be designed to take into account maximum axial loading. If an emergency slip and seal assembly is run this might affect the maximum axial loading.

References

- An Industry Recommended Practice (IRP) for Canadian Oil and Gas Industry – Volume 5, November 2011.
- API Specification 6A/ISO 10432, Specification for Wellhead and Christmas Tree Equipment
- API Standard 53, Blowout Prevention Equipment Systems for Drilling Operations.
- NACE Standard MR 0175/ISO 15156 Materials for use in H₂S-containing environments in oil and gas production

3.2.9 Well control

3.2.9.1 Principles

Well control aims to reduce hazards when drilling petroleum wells. The primary purpose of well control is to provide barriers to prevent uncontrolled release of formation fluids to surface. Well control can be categorised at two levels:

- a) Primary well control - the maintenance of a hydrostatic pressure of fluid in the well bore, sufficient to balance the fluid pressure (pore pressure) in the formations drilled. In practice a defined excess hydrostatic pressure is maintained to provide a safe level of 'overbalance' to formation pressure.
- b) Secondary well control - used when the primary well control fails - should there be a loss of hydrostatic pressure or a situation develops where the formation pressure exceeds the hydrostatic pressure, there is the potential for influx of formation fluids into the wellbore. If the well begins to flow, well control equipment BOPs will be in place to contain any influx of formation fluid and allow it to be safely circulated out of the well.

The requirements for well control systems will vary when underbalanced or managed pressure drilling techniques are employed. However, during well construction the guiding principle is to maintain at least two well control barriers in place when hydrocarbon release is possible as per 3.2.2.2 of this Code.

3.2.9.2 Means of compliance

- a) Petroleum tenure holders must have a well control standard document open for inspection at well sites, detailing requirements for equipment level, kick detection and well control techniques.
- b) During well construction, petroleum tenure holders must install well control equipment (e.g. BOP stack and wellhead) for all operations after the installation of the surface casing. Well control equipment can be terminated once the well is plug and abandoned or cased and suspended after all hydrocarbon zones and aquifers are isolated and barriers established and verified.
- c) A gas detection system must be used on the well site to identify hydrocarbon bearing formations and potential gas influx.
- d) Petroleum tenure holders must use BOP well control equipment compliant with API Specifications 16A, 16C and 16D.
- e) Petroleum tenure holders must comply with API Specifications 16C and 16D.
- f) For hydrogen sulphide applications, all well control equipment must meet the requirements of NACE MR0175//ISO 15156 Specifications for H₂S Operations.
- g) The level of BOP well control equipment required on any operation, and the configuration employed, shall be suitable for the well.
- h) Working temperature rating for well control equipment must meet the maximum anticipated continuous exposure temperature for rubber/elastomer components.
- i) All well control equipment, including connections, valves, fittings; piping etc. (excluding annular BOPs) must be rated to exceed maximum anticipated shut-in surface pressure.
- j) Petroleum tenure holders must function and pressure test BOP well control equipment as per API Standard 53, including drill through equipment, choke and kill line systems and pressure storage systems (e.g. accumulators).
- k) Petroleum tenure holders must consider DNRME Technical Guidance - Surface Gas Handling System and Mud Gas Separator Design Principles for Petroleum Drilling Operations (refer to Appendices) to ensure that the surface gas handling system for drilling operation is fit for purpose and used within operating limitations.

- l) Petroleum tenure holders must establish methods for early identification of fluid influx (well kick).
- m) Petroleum tenure holders undertaking underbalance activities shall ensure a well control risk assessment is conducted and control measures to counter the absence of primary well control are documented.

3.2.9.3 Good industry practice

- a) Additional guidance for selection and use of well control is documented in API Standard 53 - Blowout Prevention Equipment Systems for Drilling Wells.
- b) Safety critical spares for BOP equipment should be readily accessible. Storage should prevent degradation of rubber/elastomer consumables by heat or light.
- c) Methods for early identification of fluid influx may include monitoring of mud pit level, flowline flow rate and trip volume sheets derived from trip tank measurements.
- d) Regular and realistic drills pertaining to on-going or up-coming operations shall be conducted to train involved personnel in detection, prevention and recovery of a lost barrier.

References

- API Recommended Practice 59, Recommended Practice For Well Control Operations.
- API Recommended Practice 92U, Underbalanced drilling operations
- API Specification 12J, Specification for Oil and Gas Separators
- API Specification 16A/ISO 13533, Specification for Drill-Through Equipment
- API Specification 16C, Specification for Choke and Kill Systems
- API Specification 16D, Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment
- API Specification 16RCD, Drill Through Equipment Rotating Control Devices
- API Specification 16ST, Coiled Tubing Well Control Equipment Systems
- API Standard 53, Blowout Prevention Equipment Systems for Drilling Operations.
- Competency standard for petroleum and gas well drilling and well servicing, Version 4 (DNRME, 2018)
- ISO 13354, Drilling and production equipment - Shallow gas diverter equipment
- NORSOK Standard D-010, Well Integrity in Drilling and Well Operations
- Technical guidance - Surface gas handling system and mud gas separator design: Principles for drilling operations (DNRM, 2016)
- Technical information sheet - [Surface gas handling system and mud gas separator design](#) (DNRM, 2016)

3.2.10 Drilling fluids

3.2.10.1 Principles

The primary objectives for drilling and completions fluids are to:

- a) Minimise impacts to health and safety of personnel and damage to the environment
- b) Maintain primary well control as per the well barrier requirements
- c) Optimise hole conditions for the retrieval of quality geological and reservoir data
- d) Minimise reservoir damage and therefore optimise well productivity
- e) Improve drilling performance, thereby reducing overall well costs.

The majority of onshore wells in Australia are drilled using a water-based drilling fluid. It may be either fresh water or may be based on salt brine. Potassium chloride (KCl), the principal salt component, is often used as a weighting agent and to help control swelling clays. Barite, an inert weighting agent, may also be used to maintain required fluid density. Organic polymers or clay may be added to the base fluid to raise the viscosity and aid in removal of drill cuttings.

After use, drilling fluid may be returned to the drilling sumps where the solids settle to the bottom of the sump. The liquid may then be recycled and circulated for use. Losing drilling fluids down hole is undesirable as they are the primary means of controlling hydrostatic pressure within the well, and maintaining removal of formation cuttings. When a loss of fluid is detected, lost circulation material (LCM) may be incorporated in the drilling fluid. LCM prevents fluid loss by blocking the pores/fractures in the drilled rock at the wellbore.

Drilling fluids and additives are regulated under the environmental authority issued under the *Environmental Protection Act 1994*.

3.2.10.2 Means of compliance

- a) Drilling fluids must be selected and managed to ensure all products used during well operations on petroleum wells are used in accordance with the manufacturer's recommendations and relevant material safety data sheets (MSDS). The name, type and quantity of each chemical used on each well throughout the well construction process must be recorded.
- b) The petroleum tenure holder must carry out testing of the active drilling fluid in accordance with API RP 13B a minimum of twice per day.
- c) Where a non-aqueous drilling fluid (NAF) is planned, an assessment must be carried out to confirm the rig is suitable for the fluid use. This must include:
 - i. suitable clean up equipment
 - ii. suitable seals and valves and loading/unloading hoses
 - iii. bunding and drip trays to ensure no spillage of fluids can go outside any area where spills may occur
 - iv. ensure full compliance with environmental regulations, such as the *Environmental Protection Act 1994*.

Training on the use and application of non-water based fluids must conform to regulatory requirements. At the end of every well where NAF has been used, a summary must be prepared, reconciling whole quantities of NAF left in the well, returned for storage/refurbishment, and discharged to the environment.

- a) Petroleum tenure holders must ensure that drilling operations through local aquifer systems are always undertaken using water or water-based mud systems until cased off and isolated.
- b) Personnel must be aware of the environmental impact and spill emergency procedures of the products and substances in use on site.
- c) Where H₂S is predicted, or deemed likely, then:
 - i. the pH of the fluid must be monitored on a regular basis (a decrease in pH may indicate H₂S contamination), high pH can be used to hold the sulphides in the mud
 - ii. sufficient Zinc Carbonate (ZnCO₃), Zinc Oxide or Ironite Sponge must be available to treat a fluid system containing up to 500 ppm H₂S.

3.2.10.3 Good industry practice

- a) Petroleum tenure holders should ensure that the drilling fluid selected is appropriate for the well design including any locally experienced drilling problems and anticipated geological conditions likely to be encountered.
- b) The use of biodegradable substances in the drilling fluid is preferred.
- c) Biocide, oxygen scavenger and/or corrosion inhibitor should be considered for all water based systems.
- d) Drilling fluid during drilling operations should be captured and recycled for reuse as much as practical.
- e) The source of water used for all well operations (drilling, workover and hydraulic fracture stimulation) should be recorded.
- f) Products should be chosen, stored, and used at concentrations that minimise the risk to health and safety and environmental harm.
- g) Lost circulation material strategies should be documented and sufficient stocks of lost circulation material kept on site for contingency purposes. The requirement should be based on field experience.
- h) The petroleum tenure holder should specify minimum stock of contingency barite on location for the particular well type (exploration, development, HPHT).
- i) For high temperature wells, density variation simulation and rheology testing at field/well conditions (e.g. FANN70 testing or equivalent) should be considered to ensure effects of wellbore temperature on the density profile of mud can be accurately predicted for well control purposes.
- j) When drilling with a closed mud system, fluid weight and viscosity in and out of the hole should be checked regularly and recorded by the Drilling Contractor/Well Servicing Contractor. This frequency should be increased during narrow pore pressure / fracture pressure window drilling.
- k) To maintain accurate volume accounting, fluid transfers should not be made from the active system while drilling through critical pore pressure ramps, unknown pore pressure zones, narrow pore pressure / fracture pressure window drilling, during cementing operations or negative flow-back/ pressure testing.
- l) Borehole stability analysis should be considered for all deviated wells >40deg inclination and for wells in areas known to be prone to well bore instability issues or tectonic activity.

References:

- API Recommended Practice 10B-6/ISO 10426-6, Methods of determining the static gel strength of cement formulations
- API Recommended Practice 13B-1/ISO 10414-1, Recommended Practice for Field testing of drilling fluids Part 1: Water-based fluids
- API Recommended Practice 13B-2/ISO 10414-2, Recommended Practice for Field testing of drilling fluids — Part 2: Oil-based fluids
- API Specification 13A /ISO 13500, Specification for Drilling Fluid Materials
- ASTM D412, Standard test Methods for Vulcanized Rubber and Thermoplastic Elastomers – Tension 1
- ASTM D471, 12 Standard Test Method for Rubber Property – Effect of Liquids
- ASTM D2240, 05 2010, Standard Test Method for Rubber Property – Durometer Hardness 1

- ISO 13503-1 Petroleum and natural gas industries - Completion fluids and materials - Part 1: Measurement of viscous properties of completion fluids
- ISO 13503-3, Petroleum and natural gas industries - Completion fluids and materials - Part 3: Testing of heavy brines
- NOHSC: 3017 1994, Guidance Note for the Assessment of Health Risks Arising from Hazardous Substances in the Workplace
- NOHSC: 7039 1995, Guidelines for Health Surveillance
- NOHSC: 1005 1994, National Model Regulations for the Control of Workplace Hazardous Substances - Hazardous Substances Information System (HSIS)
- NOHSC: 1008 2004, National Standard Approved Criteria for Classifying Hazardous Substances

3.2.11 Well evaluation, logging, testing and coring

3.2.11.1 Principles

In petroleum exploration and development, formation evaluation (FE) is used to characterise formation fluids and determine the ability of a borehole to produce petroleum. FE data can be gathered with wireline logging instruments or logging-while-drilling (LWD) tools.

In some exploration or appraisal wells, the well program may include the cutting of cores of the strata encountered. This involves drilling and retrieving a core of solid rock to surface. The core is examined for geological and geo-mechanical information and tested for fluid content.

The target formation fluids may be sampled by either drill pipe conveyed drill stem test (DST) tools, or by wireline or LWD deployed test tools. Formation or well testing may be carried out on some wells. Well tests with flow of hydrocarbons to surface require additional planning, using data such as:

- a) predicted reservoir fluids (oil, gas, H₂S, CO₂, water, etc.)
- b) reservoir temperatures and pressures
- c) objectives of the test
- d) potential for solids production
- e) predicted flow rates and productivity.

Cuttings samples, core samples, fluid samples and other samples from the petroleum well drilling process should be collected, stored and/or distributed according to legislative and regulatory requirements.

Review of offset well logs assists in setting casing strings in the correct strata to achieve well design objectives and to properly achieve the isolation requirements of the casing and cement.

3.2.11.2 Means of compliance

- a) The petroleum tenure holder must ensure equipment is available to attempt recovery of survey or logging equipment lost down hole.
- b) Local regulations must be reviewed and be followed for the management and transportation of explosives.
- c) The petroleum tenure holder must be satisfied that service companies providing radioactive or explosive materials are licensed and have procedures for the safe transport, handling and use of:
 - i. radioactive sources in formation evaluation tools (i.e. wireline logging tools and LWD tools)
 - ii. radioactive tracers
 - iii. density measurement equipment
 - iv. radioactive markers in well completions and well test strings
 - v. explosives to be used in drilling, well completions and well testing operations.
- d) If an emitting source cannot be retrieved from down hole, an approval to dispose of it must be sought from Queensland Health. The application for approval to dispose radioactive material form is available at: www.health.qld.gov.au/radiationhealth/documents/app-dispose.pdf
- e) When coring operations are conducted, the testing for gas using hand held sensors at the rig floor must be conducted while retrieving the inner core barrels as well as when opening the core barrel and examining the cores.
- f) Well testing requirements:
 - i. Well test programs must be prepared. For all DSTs a well & tool schematic must be prepared and included in the well test program.
 - ii. All well test equipment must be located in appropriate hazardous classification areas.
 - iii. Clear and accurate definitions of temperature and pressure ratings must be provided for all surface equipment. Any pressure de-rating due to elevated temperatures must be addressed in the emergency shutdown and monitoring systems.
 - iv. The line to the testing choke manifold must be rated and pressure tested to the maximum expected surface pressure as calculated from reservoir pressure less the hydrostatic of a gas column to surface plus any kill or surface treatment pressure (e.g. hydraulic fracture stimulation).
 - v. Pressure monitoring capability must be available at the wellhead. During the well test, actual flowing conditions must be recorded and compared to predicted values.
 - vi. The well test surface equipment must be designed, prepared and operated in accordance with API 6A, NACE MR-01-075, ANSI B31.3 (Spools & X-Over).
 - vii. Emergency response procedures must be in place.

3.2.11.3 Good industry practice

- a) Where appropriate (e.g. when hole conditions and pressure regimes dictate), petroleum tenure holders should ensure secondary well pressure control equipment (PCE) is in place during logging operations. This may include such equipment as wireline lubricators or pack-offs.
- b) Casing and tubing stress analysis should consider the well test load cases to confirm operating envelope for the well, if applicable.
- c) Hole conditions should be assessed prior to running emitting sources into a petroleum well.

References:

- Australian Radiation Protection and Nuclear Safety Agency (ARPANSA) - Disposal of Naturally Occurring Radioactive Material (NORM)
- NOHSC: 1013 1995, National Standard for Limiting Exposure to Ionising Radiation
- NOHSC: 3022 1995, Recommendations for Limiting Exposure to Ionising Radiation
- Queensland application for approval to dispose radioactive material:
www.health.qld.gov.au/radiationhealth/documents/app-dispose.pdf

3.2.12 Hydraulic stimulation/flow-back operations

3.2.12.1 Principles

Hydraulic stimulation and flow back operations are conducted to improve recovery of hydrocarbons. Petroleum tenure holders seek:

- a) To ensure protection of aquifers is maintained during all operations phases for hydraulic stimulation and flow back
- b) To ensure operations are carried out such that the well operating envelope is not exceeded and well barriers are maintained
- c) To use and source water as per approved regulatory practices
- d) To flow back fluids in such a manner as to ensure all recovered fluids are isolated and do not come into contact with aquifers or pollute soil or soil substrate.

3.2.12.2 Means of compliance

- a) During the well design and planning process, petroleum tenure holders must identify any aquifers at risk of being impacted by hydraulic stimulation operations and fluids.
- b) If any such aquifers have been identified, hydraulic stimulation activities must be designed to not impact these aquifers.
- c) Hydraulic stimulation fluid additives must be selected and managed to ensure all products used during well procedures on petroleum wells are used in accordance with the manufacturer's recommendations and relevant material safety data sheets (MSDS).
- d) The name, type and quantity of each product (including chemical names) used on each well for hydraulic stimulation must be recorded.
- e) Hydraulic stimulation for gas wells requires verification of cement bond quality using appropriate cement evaluation tools.
- f) If the annulus between the production casing and the surface/intermediate casing has not been cemented to the surface, the pressure in the annular space must be monitored and controlled while conducting hydraulic fracture stimulation.

- g) The pressure relief valves on the pump units must be set so that the pressure exerted on the casing does not exceed the working pressure rating of the casing and wellhead.
- h) Post hydraulic fracture stimulation clean-up flow-back or produced fluids shall be recovered and managed as per approved regulatory practices.

3.2.12.3 Good industry practice

- a) Stimulation design should take into account location of known faults.
- b) Petroleum tenure holders should consider the risk of casing deformation as part of the well design risk assessment process and they should document any resultant control measures in the operations programme(s).
- c) The use of industry recognised software and geo-mechanics data should be used to develop the final stimulation design.
- d) The proposed design of the fracture geometry should be included in the stimulation design including (fracturing) target zones, sealing mechanism(s) (both natural geological seals as well as adequate casing and annular cement) and aquifers, so as to minimise possibility of stimulation fluids migrating from the designed fracture zone(s).
- e) Water used in hydraulic stimulation operations should be captured and recycled for reuse as reasonably practical.
- f) As far as reasonably practicable, fluids with the lowest toxicity should be used in hydraulic stimulation, and the concentrations used should be the minimum required to facilitate effective operations. Chemical suppliers should be required to meet these guidelines.
- g) Volumes of injected fluid should be accurately monitored.
- h) Petroleum tenure holders should refer to API Guidance Document HF1, Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines.

References

- API Guidance Document HF1, Hydraulic Fracturing Operations— Well Construction and Integrity Guidelines
- NOHSC: 3017 1994, Guidance Note for the Assessment of Health Risks Arising from Hazardous Substances in the Workplace
- NOHSC: 7039 1995, Guidelines for Health Surveillance
- NOHSC: 1005 1994, National Model Regulations for the Control of Workplace Hazardous Substances - Hazardous Substances Information System (HSIS)
- NOHSC: 1008 2004, National Standard Approved Criteria for Classifying Hazardous Substances
- NOHSC: 2007 1994, National Code of Practice for the Control of Workplace Hazardous Substances

3.2.13 Well integrity Management

3.2.13.1 Principles

Monitoring and maintenance is required to preserve the well and its equipment in a suitable condition for their useful life. Well integrity management systems for subsurface assets aim to ensure the wells meet operational availability and well integrity goals.

Wells are designed to be operated such that:

- a) Well barrier status is known and technical integrity risks are managed
- b) Well Operating Envelopes are not exceeded.

3.2.13.2 Means of compliance

- a) The petroleum tenure holder must be able to demonstrate that verification of well integrity and barriers exists through maintenance and monitoring through the establishment of a well integrity management system. Monitoring mechanisms and frequencies are to be determined by a risk assessment or asset integrity management guidelines.

The well integrity management system must outline:

- i. regular wellhead maintenance and inspection for leaks
 - ii. routine operational visits
 - iii. monitoring of annuli pressures
 - iv. barrier maintenance and verification
 - v. risk assessment and response levels for impaired barriers
 - vi. steps for re-establishing barriers when compromised
 - vii. well integrity records to be maintained.
- b) The petroleum tenure holder is responsible for ensuring current documented records are maintained clearly stating the existing risk level of wells and any other observations related to well integrity. The documented records shall also contain the operational status and completion status of wells.
 - c) In order to continue operating a well which has a certain assigned risk level, a risk assessment must be conducted based on the severity of exposure in line with the petroleum tenure holder's risk assessment process.

3.2.13.3 Good industry practice

- a) Well barriers should be identified and monitored/tested along with their related function and associated acceptance criteria as necessary. The barriers should be maintained as necessary through the well life cycle and re-established / compensated for when impaired. Parameters that could affect well integrity negatively should be monitored.
- b) Casing and tubing wear due to corrosive fluids and erosion should be assessed during the well life cycle and its impact on well integrity.
- c) An annulus pressure management plan should be in place for wells with trapped annuli from installation to final abandonment. Monitoring of the annuli should take place periodically by the petroleum tenure holder over the life of well to allow for effective engineering design for future workover operations.

References:

- Code of Practice for leak management, detection and reporting for petroleum operating plant, Version 4 (DNRME, 2018)
- ISO 16530-2, Well integrity - Part 2: Well integrity for the operational phase
- NOHSC: 1003 1995, National Exposure Standards for Atmospheric Contaminants in the Occupational Environment
- NORSOK Standard D-010, Well integrity in drilling and well operations
- Queensland Environmental Protection (Air) Policy 2008

3.2.14 Workover and Intervention

3.2.14.1 Principles

Well workovers and interventions can be done either as remedial work to restore barriers or to possibly enhance production and reconfigure the completion of the well. The workover may involve replacing internal piping, testing pressure seals and measuring or logging well parameters such as flow rates and temperatures in the well, fluid sampling and pipe integrity.

The completion needs to be designed to operate within the maximum expected pressures and load conditions until final abandonment.

3.2.14.2 Means of compliance

- a) The petroleum tenure holder must ensure well barriers are in place to intervene on the well and if necessary risk assess any deviations as per 3.2.2.2 of this Code.
- b) The petroleum tenure holder must use fit for purpose well design and construction materials as dictated in 3.2.5.2 of this Code.

3.2.14.3 Good industry practice

- a) Well barrier schematics should be developed and included in the workover/intervention program. Barrier verification requirements should be clearly outlined in the well workover/intervention program.
- b) During well intervention, or workovers when equipment is removed from a well or depressurised for maintenance, a breakdown or visual inspection should take place of all equipment to confirm condition after being in service.
- c) Evidence of corrosion should be used to determine mechanical integrity and help predict possible issues for intervention in similar wells.
- d) All new barriers or new operating envelopes should be verified and clearly documented and recorded prior to handover of well back to production or abandonment.

References:

- Code of Practice for leak management, detection and reporting for petroleum operating plant, Version 4 (DNRME, 2018)
- ISO 16530-2, Well integrity - Part 2: Well integrity for the operational phase
- NORSOK Standard D-010, Well integrity in drilling and well operations

3.2.15 Well suspension and abandonment

3.2.15.1 Principles

Abandonment and suspension of wells as outlined in this Part applies only to petroleum wells constructed under this Code.

Well abandonment is conducted such that well barriers contain and control wellbore fluids, provide structural support and otherwise retain well integrity throughout the well abandonment load conditions.

Barriers used for the abandonment of a well or a section of a well are permanent well barriers. The only permanent well barriers are open hole cement plugs or cement plug in casing with good quality cement on the outside. Other materials may be considered by the petroleum tenure holder but need qualification so that they can be considered permanent barriers.

The abandonment objectives are to ensure:

- a) All aquifers are isolated from the surface and from permeable hydrocarbon zones
- b) Permeable formations containing fluids at different pressure gradients and/or significantly different salinities are isolated from each other to prevent crossflow
- c) Discrete, permeable hydrocarbon zones are isolated from each other (unless co-mingling of discrete zones is permitted). If co-mingling permitted, a minimum of one well barrier is set above the shallowest co-mingled zone
- d) The site is left safe and free from contaminants.

The primary considerations for **suspension** of a petroleum well are to ensure that:

- a) All fluids from the well are contained, and that water cannot enter the well from the surface
- b) Monitoring requirements can be met and that production can readily be resumed
- c) All safety requirements are met.

Two tested well barriers are used for well suspension, except:

- a) During re-entry, workovers and other maintenance work
- b) During temporary suspension of open hole sections due to weather or other operational reasons such as batch operations.

The following matters should be considered when abandoning or suspending a well:

- a) the construction characteristics of the well and well integrity status at time of suspension or abandonment
- b) integrity of the cement column
- c) geological formations encountered
- d) potential loss zones
- e) hydrogeological conditions (i.e. location of aquifers)
- f) environmental risk
- g) regulatory requirements, title conditions and industry standards
- h) perforated and hydraulic fracture stimulated zones.

3.2.15.2 Means of compliance

- a) Wells must be abandoned in accordance with this Code and all relevant legislative requirements.
- b) Cement shall be used as the primary sealing material. Cement testing should be carried out as per requirements set out in 3.2.6.2 of this Code.
- c) Biocide, oxygen scavenger and/or corrosion inhibitor shall be used in water-based fluid for the abandonment process.
- d) For wells in the Great Artesian Basin (GAB), all management units, as identified in the GAB Water Resource Plan must be isolated from each other and any permeable hydrocarbon bearing zones by a minimum of two barriers. The GAB Water Resource Plan clearly identifies formations designated as aquifers for management.
- e) For wells in the Cooper / Eromanga basin in Queensland, all aquifer units, as identified by the South Australia Cooper Basin Statement of Environmental Objectives (SEO): Drilling, Completions and Well Operations must be isolated from each other and permeable hydrocarbon bearing zones by a minimum of two barriers. The SEO clearly identifies formations designated as aquifers for management.
- f) For all other wells, all aquifer units must be isolated from each other and any permeable hydrocarbon bearing zones by a minimum of two barriers.
- g) Cement plugs must conform to the requirements of the requirements as detailed in 3.2.15.2.1: *Cement plug requirements and verification methods*
- h) BOPs and/or the wellhead must not be removed until the cement plug across the surface casing shoe or the plug across the uppermost perforations has been verified.
- i) Cement plugs for abandonment or suspension must be verified as per below:
 - i. Off bottom open hole cement plugs to be verified by tagging the plug with a minimum 5000 lb (2270 kg) drill string weight.
 - ii. For consecutive stacked cement plugs with the first plug set on bottom or solid base (e.g. mechanical packer, other verified cement plug) verification of the top of good quality cement to be carried out by tagging the top plug with a minimum 5000 lb (2270 kg) drill string weight. If using a sacrificial stinger to set open hole plugs, provided no losses observed during cement placement then no tag is necessary.
 - iii. For a cased hole cement plug with the bottom of the plug exposed to open hole verification to be done by tagging the top plug with a minimum 5000 lb (2270 kg) drill string weight and by pressure testing to 500 psi (3.5 MPa) above the estimated (or previously recorded) leak off pressure (within the limits of the casing and wellhead pressure ratings).
 - iv. For a cased hole cement plug supported by a pressure tested bridge plug, verification may be by post cement job report and calculations, or by tagging the plug with a minimum 5000 lb (2270 kg) drill string weight.
 - v. For an unsupported cased hole cement plug barrier not exposed to open hole below, verification to be done by tagging the plug with a minimum 5000 lb (2270 kg) drill string weight.
 - vi. For a final surface cement plug extending from ground level no verification is required. A shallow set plug is not considered a permanent barrier given the very low formation pressures at ground level. Well barriers to be established with the plugs below the surface cement plug.

- j) Prior to wellhead removal, petroleum tenure holders must confirm zero pressure on any casing or annulus. Wellheads must be removed, and casing must be cut as per (f).
- k) A wellhead marker plate must be installed as per legislative requirements.
- l) Complete and accurate records of the entire abandonment procedure must be kept, with these records submitted as part of the legislative reporting requirements for the abandonment of petroleum wells.

3.2.15.2.1 Cement plug requirements and verification methods

Figure 8: Cement encased casing - well barrier

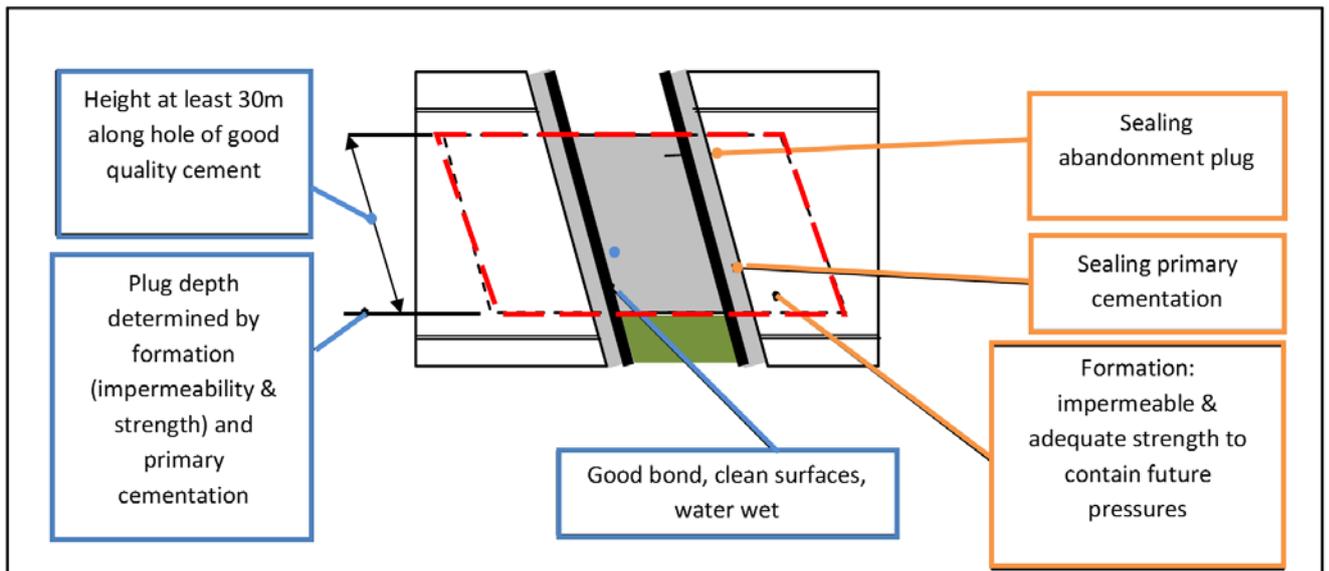
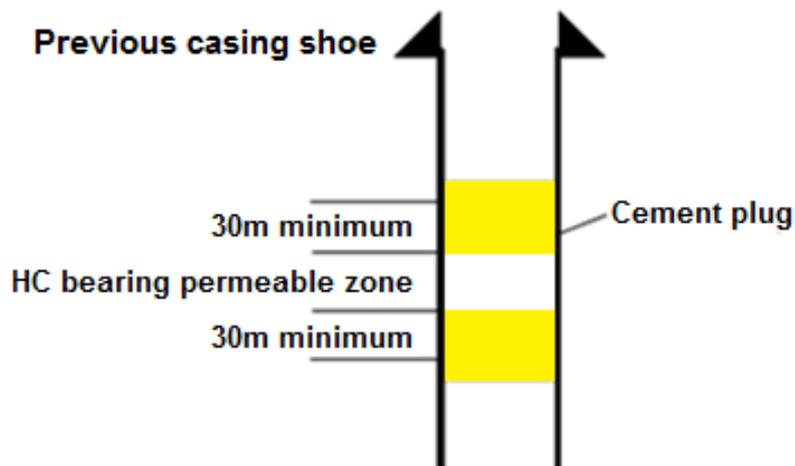


Figure 9: Open hole / uncased hole section

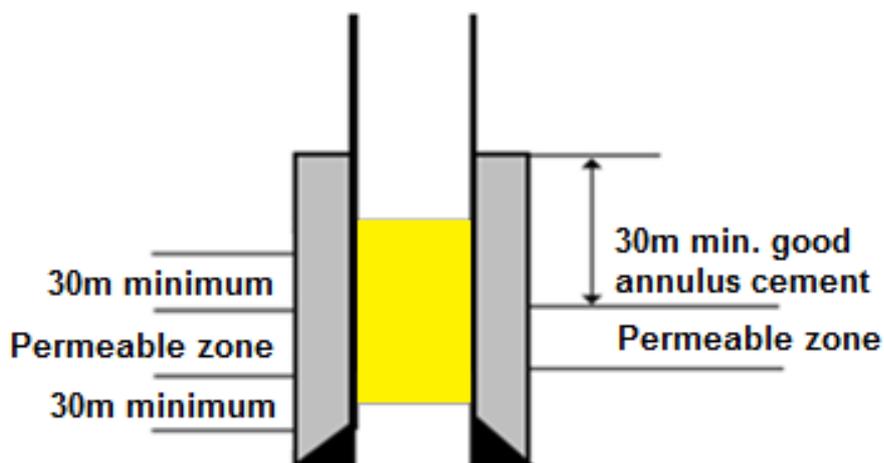


Case: Open hole / uncased hole section

Description and verification

- Verified cement plug(s) must be placed to provide cement coverage at least 100 ft. (30 m) above and 100 ft. (30 m) below the top of any permeable hydrocarbon or aquifer and between permeable zones of different pressure regimes or salinity.

Figure 10: Cased hole section

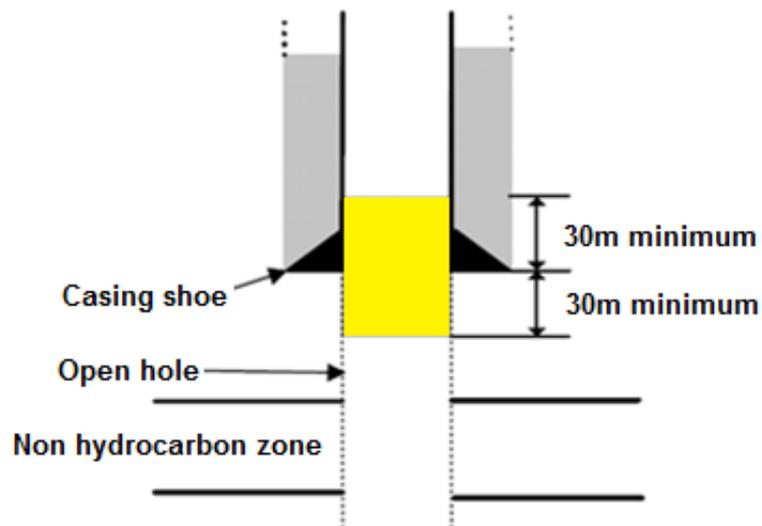


Case: Cased hole section

Description and verification

- Verified cement plug(s) placed adjacent good annulus cement must be placed to provide cement coverage at least 100 ft. (30 m) above and 100 ft. (30 m) below the top of any permeable hydrocarbon or aquifer and between permeable zones of different pressure regimes or salinity.

Figure 11: Casing shoe with open hole below

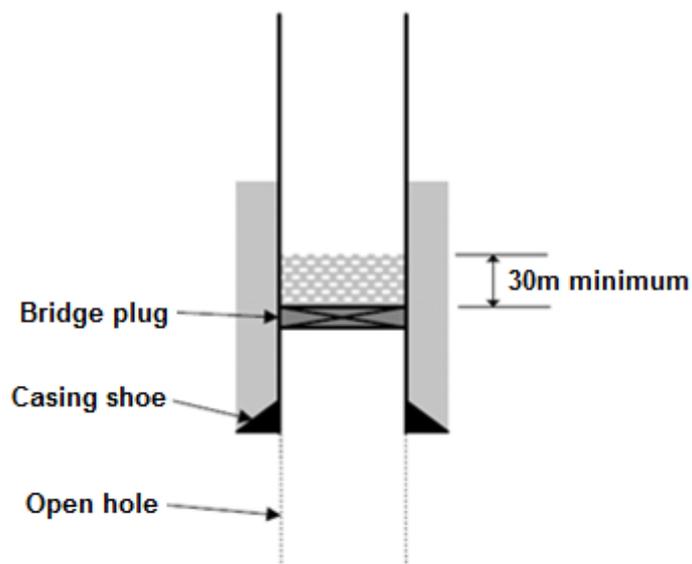


Case: Casing shoe with open hole below

Description and verification

- Verified cement plug(s) must be placed to provide cement coverage at least 100 ft. (30 m) above and 100 ft. (30 m) below the previous casing shoe.

Figure 12: Casing shoe with open hole below (with lost circulation)

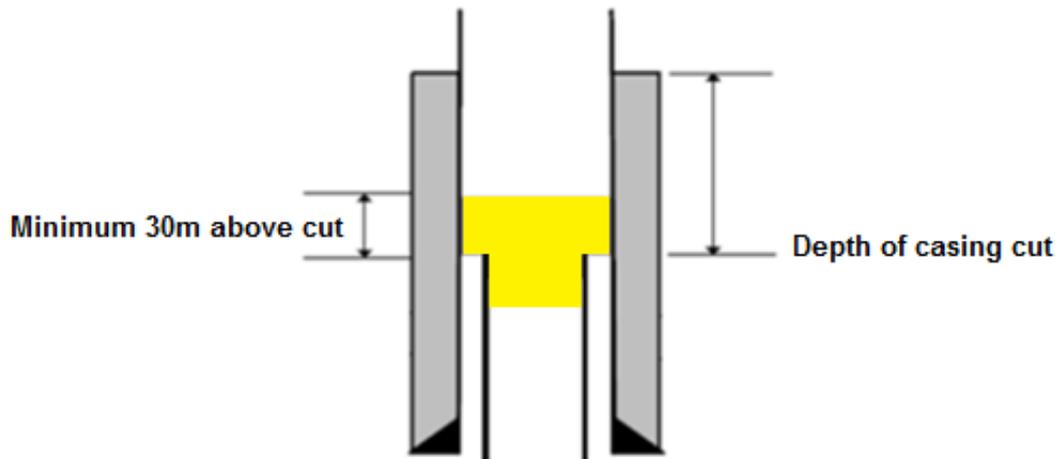


Case: Casing shoe with open hole below (with lost circulation)

Description and verification

- Where lost circulation conditions exist a mechanical barrier may be set as close as is practicable above the casing shoe (but typically not within the drilled out shoe track) with at least a 100 ft. (30 m) cement plug set above the mechanical barrier, adjacent to good annulus cement.

Figure 13: Cut and recovered casing

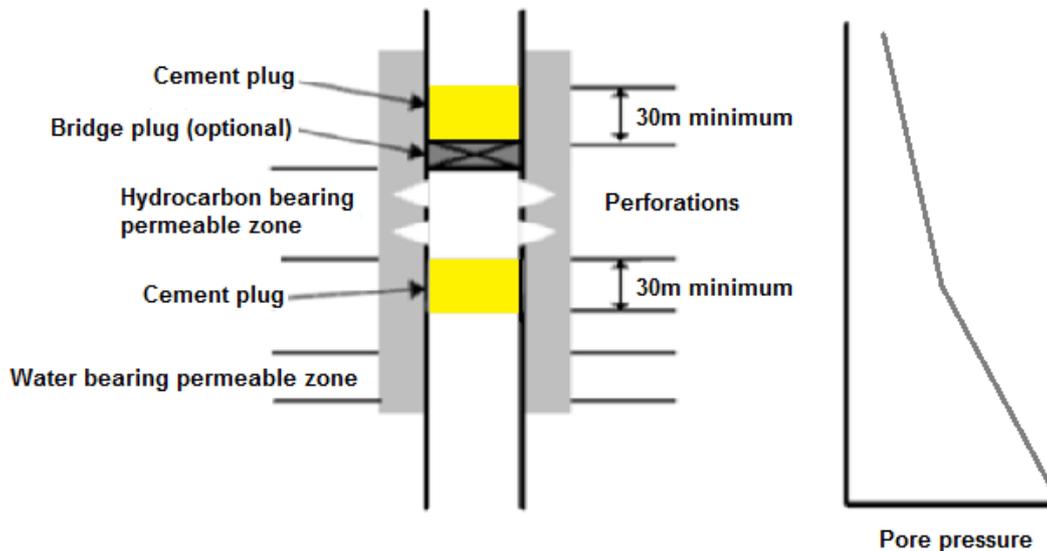


Case: Cut and recovered casing

Description and verification

- Verified cement plug(s) must be placed to provide cement coverage at least 100 ft. (30 m) above and 100 ft. (30 m) below the casing cut.

Figure 14: Perforated casing

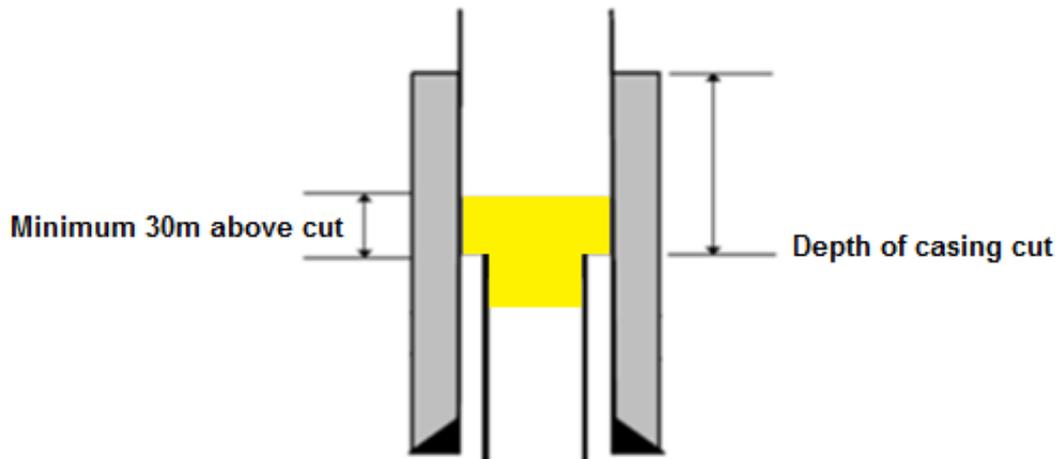


Case: Perforated casing

Description and verification

- Verified cement plugs must extend at least 100 ft. (30 m) above perforated intervals.
- A mechanical barrier with cement on top may be used if independently verified and tested.
- Verified cement plug must be used to isolate perforated intervals of different pressure regimes, as per regulatory requirements. If commingling allowed, one plug placed above the perforated intervals is sufficient.

Figure 15: Production or HPHT zone Liner Laps



Case: Production or HPHT zone Liner Laps

Description and verification

- A cement plug barrier should be set across each liner top in the form of a T-plug with at least 100 ft. (30 m) of cement below to 100 ft. (30 m) of cement above liner top

Case: Wellhead removal

Description and verification

- Cut casing at or below ground level for wells and a minimum of 4 ft. (1.2 m) below ground level.

Case: Surface cement plug

Description and verification

- A surface cement plug a minimum of 30 m must be set in the inner most casing string.

3.2.15.3 Means of compliance for suspension of wells and bores

Two tested well barriers must be used for well suspension, except:

- a) during re-entry, workovers and other maintenance work
- b) during temporary suspension of open hole sections due to weather or other operational reasons such as batch operations.

3.2.15.4 Good industry practice

- a) It is preferred to use integrated open hole volume calculated from calliper logs (when available) to calculate cement volumes.
- b) Balanced cement plugs should be set on a hi-vis pill unless setting first plug directly on hole bottom.
- c) Balanced cement plug volumes pumped should incorporate allowances for open hole and cased hole contamination.
- d) In order to pull dry pipe after placing a balanced cement plug, the plug should be well under-displaced to enable the plug to fall into a hydrostatically balanced position.

3.2.16 Recording and reporting data

3.2.16.1 Principles

Petroleum tenure holders are to maintain records associated with drilling, completion, workover and well abandonment.

Construction of a new water bore and conversion of a petroleum well to a water bore has additional requirements under P&G Regulations relating to information that must be provided to other regulators, as well as information outlined under Part 4 of this Code.

3.2.16.2 Means of compliance

Under the P&G Act a number of mandatory well reporting requirements are stipulated. It is the responsibility of the petroleum tenure holder to ensure that these reporting requirements are met.

3.2.16.3 Good industry practice

Records to be maintained for each well, or group of similar wells where appropriate, may include the following:

- a) engineering design basis
- b) kick tolerance/well control design assumptions
- c) BOP pressure testing requirements, and actual test records
- d) laboratory test results for cement slurries
- e) workover/intervention records and reports
- f) final directional survey listing
- g) service company reports
- h) well integrity records.

References:

- ISO 16530-2, Well integrity - Part 2: Well integrity for the operational phase
- NORSOK Standard D-010, Well integrity in drilling and well operations
- Oil and Gas UK OP071, 2015, Guidelines for the suspension and abandonment of wells

4 Additional and alternative requirements for water bores

4.1 Introduction

This Part comprises additional and alternative requirements which may be used for construction of water bores by petroleum tenure holders. It covers water observation bores, water supply bores and injection bores constructed for the purpose of injection of associated water into aquifers for long term storage.

This Part is based on standards and guidelines from the third edition of the MCRWBA, and on the MSWBIAB. It follows then, that any updating of the MCRWBA to a fourth edition should be accompanied by a revision of this Code.

4.2 General water bore construction requirements

4.2.1 Principles

Three ways for petroleum tenure holders to construct water bores on their tenures are:

- a) Under s.282(1) of the P&G Act, where a bore can be constructed by a licensed water bore driller in accordance with the MCRWBA.
- b) Under s.282(2) of the P&G Act, where a bore can be constructed without a water bore driller under either:
 - i. provisions of Parts 2 and 3 of this Code
 - ii. provisions of Parts 2 and 3, plus alternative details provided under Part 4 of this Code. Where construction is likely to intersect known hydrocarbon producing zones, a risk assessment is required to demonstrate the hydrocarbon is being adequately managed before deviating from specifications in Parts 2 and 3 of this Code.
- c) Details for conversion of a CSG well and petroleum well to a water bore under s.283 of the P&G Act are provided in 4.9 of this Code.

4.2.2 Means of compliance

- a) Casing for water bores must be assessed. Where this assessment shows casing need not comply with specifications in Parts 2 and 3 of this Code, then bore casing, including inert casing, must conform to either well casing standards in this Code, or with the standards for water bores listed in Appendix 5.
- b) Purpose built water supply bores must have a minimum production casing inside diameter of 125 mm. This specification is consistent with that in the MSWBIGAB.
- c) Water bores constructed either fit for purpose or through conversion under this Code require a drill log form, located with this Code on the DNRME website, to be completed and submitted to the Water Act regulator within 60 business days after the day drilling starts.

4.3 Maximising water entry for constructed water bores

4.3.1 Principles

The method of completion across the water entry zone of the bore should:

- a) allow efficient entry of water into the bore
- b) stabilise the formation
- c) prevent unacceptable ingress of materials from the formation.

Water can enter the water production zone through:

- a) slotted or perforated casing
- b) screens
- c) gravel pack with associated screen or slotted casing.

Screens can be telescopic, in which case they are inserted through the casing, and not usually installed with an artificial gravel pack, or in-line, where they are installed as part of the continuous casing string. In competent formations a screen may not be required.

4.3.2 Means of compliance

Where a bore intersects sediments of an artesian basin, such as the Great Artesian Basin, the production zone must have screens or slotted or perforated casing:

- a) installed 'in line' with the production casing
- b) on an inner liner telescoped through the production casing to the bottom of the hole and overlapping the production casing by more than 10 m. This overlap does not require cementing.

4.3.3 Good industry practice

4.3.3.1 Slotted casing

- a) Slotted casing is preferably factory machine slotted, drilled, or perforated casing with a regular series of small perforations.
- b) Slotted casing is normally made to correspond to the thickness of the water producing aquifer.
- c) The use of numerous short, narrow slots located to maintain maximum compressive strength in the casing, rather than a few large slots, is preferable. Suitably placed perforations such as small-diameter round holes may also be used.
- d) Slotted casing should be designed so that the size and shape of slots will permit adequate flow, but continue to retain water bearing strata over time.
- e) Slots alone may not be sufficient in relatively loose, fine formations. In such cases a suitably graded well-rounded (not crushed) gravel packed in the annulus between the casing and the hole wall will retain the formation.

4.3.3.2 Screens

- a) Unconsolidated sand and gravel formations are not suited to slotted casing, particularly with high yielding bores, and should be supported by a screen to ensure the bore remains open and water entry rates are high. Screens are normally manufactured from wedge shaped stainless wire, wound with the desired aperture between each winding onto a cylindrical frame. Screens can also be manufactured from other materials.
- b) Screens should always be sealed at the bottom.
- c) The sealing tube on the screen should overlap the casing by one metre to ensure loss of the screen or bore does not occur.
- d) Where the formation is a mix of sand, coarse sand and gravel, with less than 10% fine sand, a gravel pack may not be required. In this case the screen aperture size should be selected so that it retains 40–60% of the sieved water-bearing formation.
- e) The screen should be placed into the borehole within a casing string adjacent to the water bearing formation. Sometimes screens of varying aperture sizes can be selected to match the finer and coarser formation layers.
- f) Sieve analysis of formation material sampled during drilling can be carried to determine appropriate construction detail, screen aperture and gravel pack size. Greater detail of sieve analysis is provided in the MCRWBA and in AS 1141.11.1 Methods for sampling and testing aggregates - Particle size distribution - Sieving method.

4.3.3.3 Gravel pack

- a) For finer formations, gravel packs between 50mm and 120 mm thick will improve water flow into the screen, and support the formation where required. However, a minimum annular thickness of 100 mm is recommended to enable proper placement of the gravel. Gravel packs can also be purchased as part of a pre-packed screen.
- b) Because gravel packs are generally used against uniformly graded fine sands, the packing material should also be uniform.
- c) The gravel pack should consist of washed well-rounded gravel of selected grain size. The gravel pack material should be five times the diameter of modal formation material size measured through sieve analysis.
- d) The screen aperture should be 20% smaller than the diameter of gravel pack stone, and the gravel pack extended above the screen to allow for settlement. The screen aperture should retain 80–100% of the pack material.
- e) Centralisers made of inert material or the same material as the screen should be installed over the screened interval at six metres spacings to ensure a uniform gravel pack.
- f) The gravel pack should be developed to flush fine material from the formation as outlined in 4.4 of this Code.

4.4 Water bore development

4.4.1 Principles

Bores are developed to:

- a) remove introduced products
- b) improve near well permeability
- c) reduce entry losses
- d) reduce entry of suspended solids
- e) increase well efficiency.

Bore development is performed to bring a bore to its maximum production capacity by optimising bore efficiency and specific capacity and stabilising aquifer material and controlling suspended solids. The development usually involves the use of various chemical and/or mechanical agitation methods, the selection of which will depend on the type of equipment available, the construction of the bore, and the aquifer type.

A number of methods are used to remove fines and stabilise aquifer material, these include:

- a) air lifting and jetting
- b) surging
- c) pumping
- d) bailing
- e) adding dispersants and detergents.

Chemical methods include the use of dispersants and detergents to wet, break down and allow clay material and fines to be removed from the formation. Final development is usually by mechanical means. The aim of mechanical methods is to remove from the annulus clays and compacted materials from drilling operations, as well as fine materials from the formation. During development fines drawn through the screen are periodically removed.

4.4.2 Good industry practice

- a) Development methods should involve techniques that progress from gentle to vigorous agitation.
- b) Rapid de-watering of the bore should be avoided in the early stages of development as it may collapse the screen or casing or, in the case of a telescopic screen, relocate the screen to a higher and undesirable location inside the casing.
- c) Successful development will result in a virtually sand and silt free bore (i.e. < 5 mg of particulate matter per 1000 litres).
- d) Completion of development is indicated by low sand/silt loads in extracted water and no increases in the specific capacity of the bore with additional development.

4.5 Headworks for water bores

4.5.1 Principles

After a bore has been drilled and tested it is important to secure the bore and protect it from damage and from the entry of any contaminants. These works include installing headworks. Also, if the bore is located in an area of potential flooding, the casing should be installed so that the top of the casing is above flood level where practicable. Tongue type valves (gate valves) should be installed on artesian bores to assist in reducing water hammer that can occur on rapid closure of other valve types.

4.5.2 Means of compliance

Headworks for water bores must be assessed under 4.2 (b) (ii) of this Code. Where this assessment shows headworks need not comply with specifications in Parts 2 and 3 of this Code, headworks specifications must conform to either well head standards in this Code, or be in accordance with standards specified in chapter 16 of the MCRWBA. The API and Australian standards for artesian bores are listed in Appendix 2 of this Code.

4.5.3 Good industry practice

- a) Flowing wells should be fitted with a full diameter main isolating valve to assist future bore maintenance and rehabilitation.
- b) At all times the driller should ensure precautions are taken to prevent foreign material or surface water from entering the bore.
- c) All bores or wells should be positioned so that the headworks can be protected from frequent inundation from surface water runoff. For bores located in flood prone areas, the casing should extend to above the flood level. Where this cannot be achieved the bore should be completely sealed to prevent entry of surface water.

4.6 Single casing string, single aquifer bores

4.6.1 Principles

Single casing string bores that intersect a single geological formation can be constructed from steel, stainless steel, PVC-U or fibreglass casing. Bores, constructed with PVC-U or fibreglass, provide a corrosion resistant alternative to conventional construction practices documented in this Code. Construction with PVC-U is particularly suited to shallow bores in low pressure environments.

4.6.2 Means of compliance

- a) Single casing string bores can be installed only where the bore intersects a single geological formation.
- b) For bores in a) above, cement mixtures may be used as specified in the MCRWBA in tables 11.1 and 11.2, along with the associated 24 hour wait time on cement before recommencement of drilling operations.

4.6.3 Good industry practice

- a) Monitoring bores constructed from PVC-U should be protected above the surface by a galvanised or aluminium pipe housing concreted 0.5 m into the ground.
- b) A monitoring bore should be cemented from no more than one metre above the top of the monitored aquifer to the housing concrete.

4.7 Areas where groundwater is corrosive

4.7.1 Principles

Some groundwater is corrosive to mild steel which is widely used for casing, particularly groundwater with a high concentration of dissolved CO₂.

In such environments, casing life can be very short, and use of inert casing material such as PVC-U, fibreglass (FRP and FRE) or stainless steel is the primary method of ensuring long bore life. These must be designed to meet the minimum casing design requirements. Corrosive areas in the Great Artesian Basin along with more detailed maps of the Bulimba, Flinders and Injune areas are illustrated at www.business.qld.gov.au

In these areas not all formations are corrosive, and only when groundwater is extracted from corrosive aquifers listed on the above website is inert production casing and inner liner required.

4.7.2 Means of compliance

Where a water bore is used to extract groundwater from a corrosive formation, inert materials must be used for production casing and inner lining casing.

4.8 Injection bores

4.8.1 Principles

Environmentally-sound injection of water or brine minimises the risks of surface soil and aquifer contamination. Injection bores are constructed and maintained so that casing integrity, and cementing to achieve zonal isolation ensures that all injection fluid is transported to the target formation only. Management must also ensure surface contamination by injection fluid, including through pipe delivery, road transport systems, or through poor bore integrity, does not occur. Appropriate monitoring is installed to confirm these outcomes and enable timely initiation of remedial actions should the risk of contamination be present.

Injection fluid's physical and chemical properties, along with bore screening and development where appropriate, are also important to maintain injection bore flow rates and provide a long working life for injection bores.

Note that in addition to requirements for injection bores referred to in this Code; conditions are listed on the Environmental Authority under the *Environment Protection Act 1994*. Relevant provisions under the *Water Act 2000* must also be complied with.

4.8.2 Means of compliance

- a) Injection bores are not subject to the minimum casing diameter specification in 4.2.2 (b).
- b) Injection bores must be designed and constructed such that cementing ensures the formation being injected is isolated from all other formations.
- c) When a bore is constructed for brine injection, an injection tubing string with a packer located within 30 m of the target injection zone must be installed. Brine is defined in Appendix 1.
- d) Whilst brine injection is being undertaken, potential leaks from the injection bore must be evaluated at the surface by continuous monitoring of:
 - i. pressure and flow in the injection tubing
 - ii. pressure in the tubing-casing annulus (sealed by the packer).

4.9 Conversion of CSG & petroleum wells to water bores

4.9.1 Principles

Conversion of a CSG & petroleum well to a water bore and subsequent transfer to a landowner can provide a number of benefits. These include a community benefit from the tenure holder, a low cost bore for a landowner and an environmental benefit by reducing the numbers of bores that may have been constructed if the well had not been converted.

Sometimes a tenure holder will want to convert a well to a water bore for use on the tenure. It is important to ensure that any converted bore is constructed to a high standard.

The time that a well ceases to be a CSG or petroleum well is defined under the P&G Act. Only wells that can be demonstrated to have been constructed to the requirements of the former construction and abandonment codes (first adopted in January 2012) can be converted to water bores.

In many areas landowners who own a water supply bore require a licence in accordance with an existing Water Resource Plan (WRP), Declared Sub-Artesian Area or Wild Rivers Area applicable at the location of the bore. Some bores transferred to a landowner will be done so under an existing licence.

The licence, or its associated Development Permit, will specify the formation from which take of groundwater is authorised, and therefore casing perforations can be made. In some WRP areas, such as the Great Artesian Basin, groundwater intake is not permitted within certain distances of springs or other users.

Sometimes construction of bores in specified areas can be prohibited by a moratorium.

4.9.2 Means of compliance

- a) A CSG and petroleum well, constructed in a corrosive area, must not be converted to a water bore unless it meets the requirements of 4.7 of this Code.
- b) The minimum casing diameter of a well to be converted to a water bore is API 5L 4.5 inch (114.3 mm) casing.

4.9.3 Good industry practice

Before conversion and transfer of a well to a landowner, or transfer of a purpose built water bore to a landowner, DNRME should be contacted to confirm that the location of proposed take through the bore is permitted under relevant licensing regulations.

Appendix 1 – Glossary

Table: Terms and definitions

Term	Definition
Abandonment	A process which involves shutting down the well and rehabilitating the site. It includes decommissioning the well.
Abnormal pressure	Formation or zones where the pore pressure is above the normal, regional hydrostatic pressure.
ALARP	As low as reasonably practicable (used in evaluating risk).
Annulus/Annular space	The space between two concentric objects, such as between the wellbore and casing or between casing and tubing, where fluid can flow. A-annulus – annulus between the tubing and production casing. B-annulus – annuli between the production casing and the previous casing.
API	American Petroleum Institute
Aquifer	A geological structure, formation or formations that holds water in sufficient quantity to provide a beneficial source of water that can be tapped by a bore. A saturated formation that will not yield water in usable quantities or qualities is not considered an aquifer.
Barrier	Any means of preventing an uncontrolled release or flow of wellbore fluids to surface. (See Well Barrier)
BOP	Blowout preventer. Equipment installed on the wellhead assemblies to contain wellbore fluids either in the annular space between casing and the tubulars, or in an open hole during well drilling, completion, and testing operations.
Bore or water bore	Includes a water observation bore, water supply bore or injection bore.
Brine	Saline water with a total dissolved solids concentration greater than 40 000 milligrams per litre, as defined in the Coal Seam Gas Water Management Policy, 2012.
Casing	A pipe placed in a well to prevent the wall of the hole from caving in and to prevent movement of fluids from one formation to another.
Casing collar	Coupling between two joints.
Casing coupling	Tubular section of pipe that is threaded inside and used to connect two joints of casing.
Casing head	A heavy flanged steel fitting connected to the first string of casing. It provides a housing for slips and packing assemblies. (See Wellhead)
Casing Shoe	The bottom of the casing string, including the cement around it, or the equipment run at the bottom of the casing string.
Cement	Powder consisting of alumina, silica, lime and other substances that hardens when mixed with water. Extensively used to bond casing to the walls of the wellbore. Different specifications of cement is used for different purposes. Can be a collective term for cement and non-cementitious materials that are used to replace cement.
Cementing	The application of a liquid slurry of cement and water to various points inside and outside the casing.
Cementing head	Component fitted to the bore for the use of cementing.
Cement plug	Portion of cement placed at some point in the wellbore.

Term	Definition
Centraliser	A device to keep the casing or liner in the centre of the wellbore to help ensure efficient placement of a cement sheath around the casing string.
Christmas tree	Control valves, pressure gauges and chokes assembled at the top of a well to control the flow after the well has been drilled and completed.
Circulation	The process of pumping a fluid down the well and back up to the surface in a drilling or workover operation.
CSG	Coal seam gas
Code	Unless otherwise specified, refers to this Code of Practice.
Company representative	An employee of the operator who supervises the operations at a drilling site or well site and coordinates the hiring of logging, testing, service and workover organisations. Also called the 'company man'.
Completion	A generic term used to describe the assembly of downhole tubulars and equipment required to enable safe and efficient production from an oil or gas well. The point at which the completion process begins may depend on the type and design of well.
Completion (or Workover) program	A petroleum tenure holder document that describes the detailed well procedures and risk mitigation for activities including completions, testing, intervention, well repair and/or abandonment.
Concrete	This is defined as a mixture of cement powder, water, sand and gravel. This mixture must set without separation.
Contractors	Third parties contracted by the petroleum tenure holder to provide well engineering equipment including drilling rigs, materials, equipment and services.
Coring	Process of cutting a vertical, cylindrical sample of the formations.
Corrosion	Any of a variety of complex chemical or electrochemical processes (except rust) by which metal is destroyed through reaction with its environment.
CSG well	A CSG well is a prescribed well as defined in the P&G Act, but only where the well is drilled on a petroleum authority and where the purpose of the well is to explore for or produce natural gas from a coal seam reservoir. It does not include shot holes. A CSG well includes the casing for the well and any wellhead for the well attached to it.
Decommissioning (well)	Also known as plug and abandonment. A process which involves decommissioning a well and rehabilitating the site.
DNRM	The former Queensland Department of Natural Resources and Mines
DNRME	Queensland Department of Natural Resources, Mines and Energy
Drilling fluid/mud	Circulating fluid that can lift cuttings from the wellbore to the surface and to cool down the drill bit.
EC	Electrical conductivity.
Evaluation	Includes mud logging, wireline logging and formation evaluation while drilling, coring and well testing.
Exploration well	A well constructed to explore for CSG. In this Code, the definition of exploration wells also applies to appraisal wells and gas monitoring wells.
Flowing well	Also known as an artesian well. A well from which groundwater is discharged at the ground surface without the aid of pumping.

Term	Definition
Formation pressure	Force exerted by fluids in a formation
Former construction and abandonment codes	Either of the former Code of Practice for the construction and abandonment of coal seam gas wells and associated bores in Queensland, or the former Code of Practice for the construction and abandonment of petroleum wells and associated bores in Queensland.
Garrett gas train	An instrument used for quantitative analyses of sulfides and carbonates in drilling fluid.
Gas injection well	A well into which gas is injected for the purpose of maintaining or supplementing pressure in reservoir and/or for gas storage.
Good cement	Cement that has been verified to position, quantity and quality
Horizontal well (CSG wellbore)	<p>A high-angle well (with an inclination of generally greater than 85°) drilled to enhance extended reach by placing a long wellbore section in a generally horizontal direction along a coal seam.</p> <p>Horizontal wells are normally characterized by their build-up rates and are broadly classified into three groups (long radius, medium radius and short radius) that dictate the drilling and completion practices required.</p> <p>A horizontal well is a product of directional drilling where the departure of the wellbore from vertical exceeds about 85 degrees. Note that some horizontal wells are designed such that after reaching true 90-degree horizontal, the wellbore may actually start drilling upward. In such cases, the angle past 90 degrees is continued, as in 95 degrees, rather than reporting it as deviation from vertical, which would then be 85 degrees. Because a CSG horizontal well typically penetrates a greater length along the coal seam, it can offer significant production improvement over a vertical wellbore.</p>
Horizontal well	Deviation of a borehole from vertical so that the borehole penetrates a productive formation at 90 degrees inclination from vertical.
HT	High temperature (HT) wells, typically ≥ 150 °C (300 °F) bottom hole static temperature.
HPHT	High pressure, high temperature (HPHT) wells, typically in industry accepted as ≥ 149 °C (300 °F) undisturbed bottom hole static temperature, ≥ 69 MPa (10,000 psi) expected surface pressure needing deployment of pressure control equipment with a rated working pressure in excess of 69MPa (10,000 psi).
Hydraulic fracture stimulation	A process used to enhance the productivity of a gas well. It involves pumping a specifically blended fluid, charged with proppant such as sand, down a well at high pressure to force passageways into the target formation(s). The proppant keeps the passageways open once the pressure is released and serves to improve the productivity of the well.
Injection well	Well through which gas is stored or fluids are injected into an underground stratum which may increase reservoir pressure.
Injection bore	Bore used to inject water or brine into a geological formation for storage; for example this would include a bore utilised by a CSG tenure holder to store associated water. See 'water supply bore'.
Intermediate casing	The string of casing set in a well after the surface casing.
kg	Kilograms
Kick	An unplanned entry of water, gas, oil or other formation fluid into the wellbore during drilling.

Term	Definition
Kick tolerance	Maximum influx volume that can be circulated out of well without breaking down the weakest zone in well
lbs	Pounds
Leak-off	The magnitude of pressure exerted on a formation that causes fluid to be forced into the formation. The fluid may be flowing into the pore spaces of the rock or into cracks opened and
Leak-off test	Progressive wellbore formation pressure test until leak-off to provide well integrity information.
Liner	A casing string that does not extend to the top of the wellbore, but instead is anchored or suspended from inside the bottom of the previous casing string.
Long radius horizontal well	A type of horizontal well with a radius of 290 to 900 m (1,000 to 3,000 ft) and a typical build rate of 2 to 6°/100 ft.
LWD	Logging while drilling, or formation evaluation while drilling
m	Metres
Managed pressure drilling	An adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore whilst drilling.
may	Is used when a standard is recommended as part of good industry practice.
Medium radius horizontal well	A type of horizontal well with a radius of 50 to 290 m (160 to 1,000 ft) and a typical build rate of 6 to 35°/100 ft.
MGS	Mud Gas Separator
mm	Millimetres
MPa	MegaPascals
MSDS	Material safety data sheet
must	Is used when a standard is mandatory.
MWD	Monitoring while drilling
Non-aqueous fluid (NAF)	Non-water based drilling fluid or well circulating fluid. Common NAF systems are diesel oil (OBM), mineral oil, or synthetic fluid (SBM) based invert emulsions.
Normal pressure	Formation or zones where the pore pressure is equal to the normal regional hydrostatic pressure.
OCTG	Oil country tubular goods, i.e. steel casing and tubing for oil and gas industry.
Offset well information	Near well information available from previous drilling in the immediate vicinity of the proposed well.
Openhole	The uncased portion of a well.
Operations	Any work conducted including rig moves, drilling, running and cementing casing, evaluation, completion, workover and abandonment.
Packer	Piece of downhole equipment that consists of a sealing device. Used to block the flow of fluids through the annular space between pipe and the wall of the wellbore.
P&G Act	Petroleum and Gas (Production and Safety) Act 2004

Term	Definition
P&G Regulation	Petroleum and Gas (Safety) Regulation 2018
PCE	Pressure control equipment
Perforating	The method of opening a well through the casing to the formation bearing the fluid to be produced.
Petroleum	A generic name for hydrocarbons, including crude oil, natural gas liquids, natural gas and their products.
Petroleum tenure holder	Reference should be made to definitions in Schedule 2 of the Petroleum and Gas (Production and Safety) Act 2004 – refers to the holder of particular petroleum authorities (authorities to prospect and petroleum leases). Note: 'holder' includes each holder recorded as a holder for the tenure
pH	Index of acidity or alkalinity of water.
Plug	Any object or device that blocks a hole or passageway.
ppg	Pounds per gallon (United States of America)
Production casing	A casing string that is set across the reservoir interval and within which the primary completion components are installed.
Production zone	Hydrocarbon producing zone of the formation.
psi	Pounds per square inch.
Pumping time	Calculated time to mix, pump and fully displace cement slurry.
Regulator	Petroleum and Gas Inspectorate – safety and health
SCADA	System control and data acquisition (usually a telemetry data and control system)
Seal	Cement mixture pumped into the bore.
Short radius horizontal well	A type of horizontal well with a radius of 6 to 12 m (20 to 40 ft) and a typical build rate of 5 to 10°/3 ft.
Short term exposure limit	A 15 minute time weighted average (TWA) exposure which should not be exceeded at any time during a working day.
SG	Specific gravity
Stratigraphic drill hole	Core or other slim holes primarily drilled for the purpose of recovering information about lithology, stratigraphy and geological structure.
Sulphide stress cracking	A form of hydrogen embrittlement which is a cathodic cracking mechanism, affecting susceptible alloys of steels.
Surface	A natural ground surface or the top of the BOP flange when installed.
Surface casing	A drilled and cemented pipe used to provide blowout protection, to seal off water/hydrocarbon sands, and prevent loss of circulation. Also used to seal off water sands, weak formations and/or lost circulation zones. In some cases surface and intermediate casing requirements are provided by the same string.
Time-weighted average (TWA)	The average airborne concentration of a particular substance when calculated over a normal eight-hour working day, for a five-day working week.
TOC	Top of Cement

Term	Definition
Underbalanced	Wellbore condition in which the pore pressure exceeds the wellbore hydrostatic pressure.
Underbalanced / managed pressure drilling	A drilling activity employing equipment and controls where the pressure exerted in the wellbore is Intentionally maintained less than (underbalanced) or close to (managed pressure) the pore pressure in any part of the exposed formations.
Water observation bore	Water bore used to monitor groundwater pressure or used to access groundwater for taking water samples. This has the same meaning as <i>water monitoring bore</i> under the Water Act 2000
Water supply bore	Includes a bore constructed for take of groundwater and a bore for injecting water or brine (injection bore).
Well or well-hole	This includes production, exploration, appraisal wells, test holes, shot holes and gas injection wells. Gas monitoring wells are classed as exploration wells in this Code.
Well barrier	Envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation or to the external environment
Well construction	Well construction includes the following phases <ul style="list-style-type: none"> • Planning and design • Drilling • Evaluation • Stimulation • Completion • Intervention and workover • Suspension • Abandonment
Well control equipment	Includes the BOP stack, BOP control system, full open safety valves, circulating hose (and circulating head), drill-string safety valves (inside BOPs), mud and cement pumps, the choke and kill lines and manifold, mud gas separator and all associated pipework and valves.
Wellhead	The system of spools, valves and associated adapters that provide pressure control for production.
Well Integrity	Application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids and well fluids throughout the life cycle of a well.
Well intervention	An operation carried out by re-entering an existing well.
Workover	Well procedure to perform one or more of a variety of remedial/maintenance operations on a producing well to maintain or attempt production increase. Examples of workover operations are pump repairs, well deepening, plugging back, pulling and resetting liners, squeeze cementing and re-perforating.

Appendix 2 – Industry standards

The following industry standards may be appropriate for the application of this Code (the list is not exhaustive and additional standards may be referenced from the appropriate web sites):

- Competency standard for petroleum and gas well drilling and well servicing, Version 4 (DNRME, 2018)
- Code of Practice for leak management, detection and reporting for petroleum operating plant, Version 4 (DNRME, 2018)
- API Guidance Document HF1, Hydraulic Fracturing Operations— Well Construction and Integrity Guidelines
- API Recommended Practice 10D-2/ISO 10427-2, Recommended Practice for Centralizer Placement and Stop Collar Testing
- API Recommended Practice 10B-2/ISO10426-2 Recommended Practice for Testing Well Cements
- API Specification 10A/ISO 10426-1 Specification for Cements and Materials for Well Cementing
- API Specification 13A /ISO 13500, Specification for Drilling Fluid Materials
- API Specification 16A, ISO 13533, Specification for Drill- Through Equipment
- API Specification 5B, Specification for Threading, Gauging, and Thread Inspection of Casing, Tubing, and Line Pipe Threads
- API Specification 5CT/ISO 11960, Specification for Casing and Tubing
- API Specification 6A/ISO 10432, Specification for Wellhead and Christmas Tree Equipment
- API Standard 53, Blowout Prevention Equipment Systems for Drilling Operations.
- API Standard 65-2, Isolating Potential Flow Zones During Well Construction
- ISO 13354, Drilling and production equipment - Shallow gas diverter equipment
- NACE Standard MR 0175/ ISO 15156 Materials for use in H₂S-containing environments in oil and gas production
- National Exposure Standards For Atmospheric Contaminants In The Occupational Environment, National Occupational Health and Safety Commission (NOHSC) document [NOHSC:1003(1995)]
- Queensland Environmental Protection (Air) Policy 2008

Petroleum tenure holders may also consider the following references, to manage well construction issues associated with the whole of life cycle requirements for petroleum wells:

- ANSI/API Specification 15HR, High Pressure Fiberglass Line Pipe
- ANSI/API Specification 15LR, Low Pressure Fiberglass Line Pipe
- API Recommended Practice 10B-5/ISO 10426-5, Recommended Practice on Determination of Shrinkage and Expansion of Well Cement Formulations at Atmospheric Pressure
- API Recommended Practice 10B-6/ISO 10426-6, Methods of determining the static gel strength of cement formulations
- API Recommended Practice 10F/ISO 10427-3, Recommended Practice for Performance Testing of Cementing Float Equipment

- API Recommended Practice 13B-1/ISO 10414-1, Recommended Practice for Field testing of drilling fluids Part 1: Water-based fluids
- API Recommended Practice 13B-2/ISO 10414-2,D, Recommended Practice for Field testing of drilling fluids — Part 2: Oil-based fluids
- API Recommended Practice 49, Recommended Practices For Safe Drilling Of Wells Containing H₂S.
- API Recommended Practice 54, Occupational Safety for Oil and Gas Well Drilling and Servicing Operations
- API Recommended Practice 5A3/ISO 13678, Recommended Practice on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements
- API Recommended Practice 5A5/ISO 15463, Field Inspection of New Casing, Tubing, and Plain-end Drill Pipe
- API Recommended Practice 5B1, Gauging and Inspection of Casing, tubing and Line Pipe Threads
- API Recommended Practice 5C1, Recommended Practice for Care and Use of Casing and Tubing
- API Recommended Practice 5C5/ISO 13679, Recommended Practice on Procedures for Testing Casing and Tubing Connections
- API Recommended Practice 5C6, Welding Connections to Pipe
- API Recommended Practice 92U, Underbalanced drilling operations
- API Specification 10D/ISO 10427-1, Specification for Bow-Spring Casing Centralizers
- API Specification 16C, Specification for Choke and Kill Systems
- API Specification 16D, Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment
- API Specification 16RCD, Drill Through Equipment Rotating Control Devices
- API Specification 16ST, Coiled Tubing Well Control Equipment Systems
- API Technical Report 10TR1 Cement Sheath Evaluation
- API Technical Report 10TR2, Shrinkage and Expansion in Oilwell Cements
- API Technical Report 10TR3, Temperatures for API Cement Operating Thickening Time Tests
- API Technical Report 10TR4, Technical Report on Selection of Centralizers for Primary Cementing Operations
- API Technical Report 10TR5, Technical Report on Methods for Testing of Solid and Rigid Centralizers
- API Technical Report 5C3, Technical Report on Equations and Calculations for Casing, Tubing, and Line Pipe used as Casing or Tubing; and Performance Properties Tables for Casing and Tubing
- Energy Institute Part 17: Volume 1: High Pressure and High Temperature (HPHT) Well Planning (2009). Model Code of Safe Practice in the Petroleum Industry
- ISO 10407, Drill Stem Design and Operating Limits
- ISO 16530-2, Well integrity - Part 2: Well integrity for the operational phase

- ISO 1872-1: 1993, Polyethylene (PE) moulding and extrusion materials - Part 1: Designation system and basis for specifications
- ISO 31000:2009 – Risk management - Principles and guidelines
- NORSOK Standard D-010, Well integrity in drilling and well operations
- Technical guidance - Surface gas handling system and mud gas separator design: Principles for drilling operations (DNRM, 2016).
- Technical information sheet - Surface gas handling system and mud gas separator design (DNRM, 2016).

These standards and specifications must only be used if they do not contradict the means of compliance stipulated in this Code.

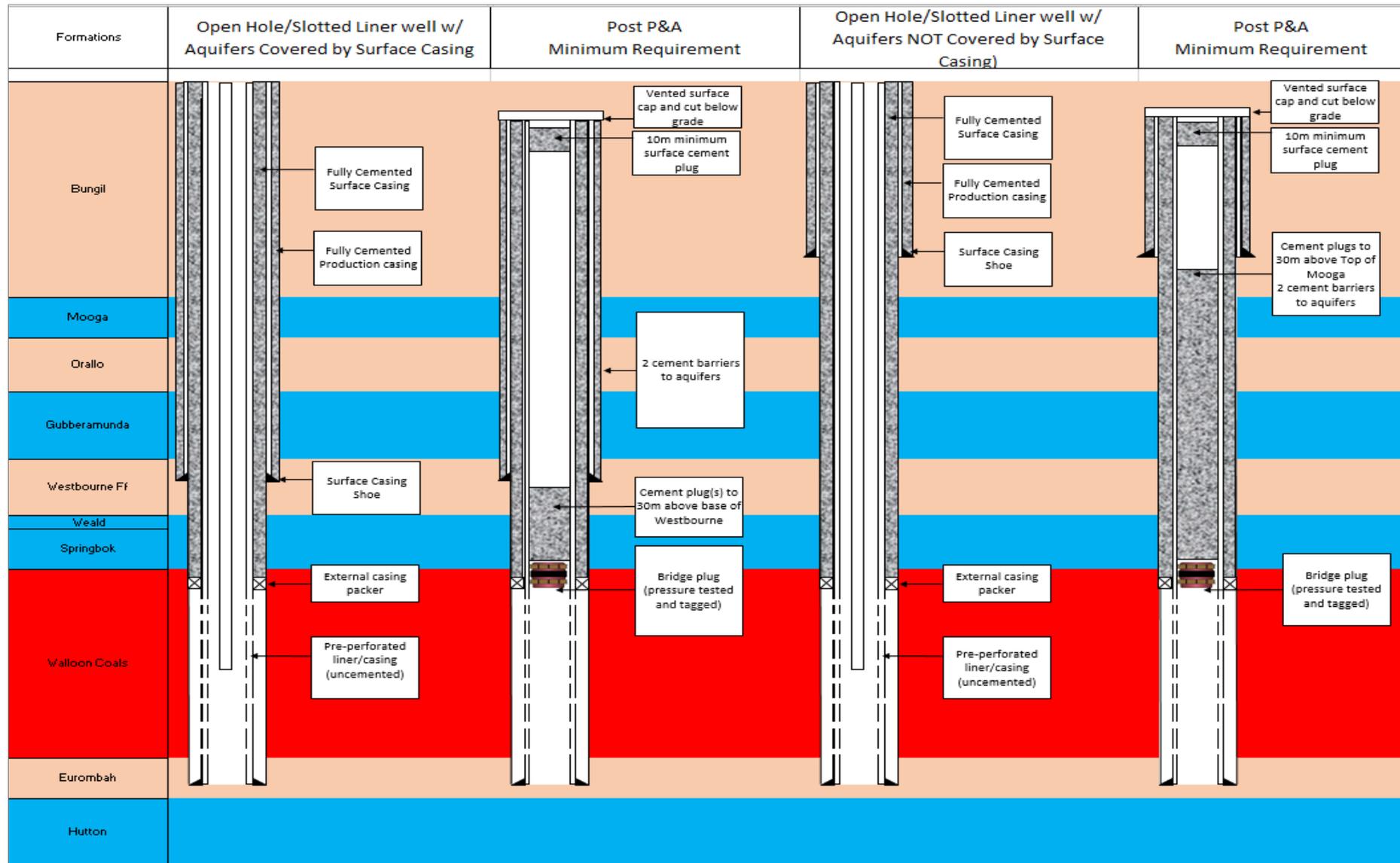
Appendix 3 – Cooper / Eromanga Basin Aquifers

The [South Australia Cooper Basin Statement of Environmental Objectives; Drilling, Completions and Well Operations](#) can be found at the following website:

www.petroleum.statedevelopment.sa.gov.au/legislation_and_compliance/environmental_register

The document outlines geological formations as aquifers in the Cooper-Eromanga Basin. They may contain permeable sands which may be in natural hydraulic isolation from each other (from shallowest to deepest), and in general isolation will be maintained between these groups.

Appendix 4 - Examples of standard Surat abandonment schematics



Appendix 5 – References

Read more www.business.qld.gov.au/industries/mining-energy-water/water/bores-and-groundwater/construction-standards on:

- [Minimum Construction Requirements for Water Bores in Australia](#)
- [Minimum Standards for the Construction and Reconditioning of Water Bores that Intersect the Sediments of Artesian Basins in Queensland](#)