Department of Natural Resources, Mines and Energy

Code of Practice

For the construction and abandonment of petroleum wells and associated bores in Queensland

Petroleum and Gas Inspectorate

Version 2

16 December 2019

Queensland Government

Table: Previous document history

Version number	Date	Document
1	11/2011	Code of Practice for Constructing and Abandoning Coal Seam Gas Wells in Queensland
2	10/2013	Code of Practice for constructing and abandoning coal seam gas wells and associated bores in Queensland
3	19/05/2017	Code of Practice for the Construction and Abandonment of Coal Seam Gas Wells and associated bores in Queensland
1	03/03/2016	Code of practice for the construction and abandonment of petroleum wells and associated bores in Queensland

Table: Document history

Version number	Date	Key changes
1	01/09/2018	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 the Petroleum and Gas (Safety) Regulation 2018
2	16/12/2019	Revisions to the document included: • Reformatted to place all petroleum well requirements in one chapter • Document title updated • Updated multiple requirements predominately to provide clarity • Updated reporting requirements to align with the regulation • Corrected typographical errors

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

Table of contents

Table of figures

Table of tables

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) with the main subordinate legislation relating to safety being the Petroleum and Gas (Safety) Regulation 2018 (P&G Safety Regulation). Another subordinate legislation, the Petroleum and Gas (General Provisions) Regulation 2017 (P&G General Provision Regulation), also states relevant requirements. The legislation is administered and enforced by the Petroleum and Gas Inspectorate (the Inspectorate).

Under the legislation, and the definition of petroleum wells in the P&G Act, petroleum tenure applies to both conventional and unconventional resources (e.g. CSG, tight gas sands, shale gas). In practice, the underlying principles of design will be similar for wells drilled for different resource types with some minor technical differences possible. This consolidated Code of Practice for the construction and abandonment of petroleum wells and associated bores in Queensland (the Code) combines the requirements from the former construction and abandonment code for CSG wells and the former construction and abandonment code for conventional and non-CSG unconventional petroleum wells. Accordingly, this Code addresses the requirements for all petroleum wells but also specifies any requirement differences between CSG wells and other (conventional and non-CSG unconventional) petroleum wells. For the purpose of this Code, the terms 'Petroleum well', 'CSG well' and 'other well' are used, and mean the following:

- As per the P&G Act, 'Petroleum well', which includes both "CSG wells" and "Other wells", is a hole in the ground made or being made by drilling, boring or any other means—
    a) to explore for or produce petroleum; or
    b) to inject petroleum or a prescribed storage gas into a natural underground reservoir; or
    c) through which petroleum or a prescribed storage gas may be produced.
- 'CSG well' means a petroleum well that is drilled to explore for or produce petroleum in association with coal or oil shale; or in strata associated with coal or oil shale mining.
- 'Other 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, operation and abandonment (decommissioning) of petroleum wells and associated bores.

The P&G Safety Regulation establishes that the means of compliance in this Code are to be complied with for the drilling, operating, converting and abandoning of petroleum 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 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 operators to comply with their obligations under Queensland’s petroleum legislation. However, it is not intended to discourage or prevent operators 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 operator'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 operator's standards, are understood and implemented where appropriate

d) the life of a petroleum 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 and water bores constructed by operators on their tenures for both conventional and unconventional oil and gas exploration and production. It covers conversion of petroleum wells to water bores.

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

This Code applies to the following well life cycle phases:

a) well planning and well design

b) well construction (up to the production wing valve of the well head/Christmas tree) including construction of new water bores by operators

c) well evaluation

d) well completion including hydraulic fracture stimulation activities

e) well production and operation

f) well integrity management

g) conversion of petroleum wells to water bores

h) well suspension

i) well abandonment

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, operation, conversion and abandonment, and Australian standards for water bore construction and abandonment.

If an operator 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. The way in which to give the notice is by:

a) Submitting the notice using the online system made available on a Queensland Government website for the purpose; or

b) Lodging the notice at the office of the Chief Inspector.

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 operators 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, P&G Safety Regulation or P&G General Provisions Regulation, the provisions of the P&G Act, P&G Safety Regulation or P&G General Provisions Regulation (as the case may be) prevail.

Compliance with this Code is directed at the operator, 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 operator 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 for petroleum wells as the relevant case may be.

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.

It should be noted that wells drilled under previous versions of the Code will be assessed against the version relevant at the time the work was conducted. However such wells should be appropriately risk assessed and flagged in the operator's well integrity management system. Operators are required to abandon wells to the standard current at the time of abandonment. If the configuration of a well drilled under previous revisions of the code prohibits an operator from meeting the current abandonment standard, the operator is required to conduct a risk assessment to confirm that all reasonable attempts are made to meet the requirement and to determine the most reasonable outcome. It is recommended that the Inspectorate be notified if this occurs.

1.4 Acknowledgements

This Code is managed by the Petroleum and Gas Inspectorate with input from the Queensland petroleum industry, government departments and other relevant stakeholders. Numerous parties have contributed to previous versions of this document as acknowledged within them. Industry and relevant government departments were given the opportunity to provide comment for this revision and the following people or companies either provided feedback or attended the consultation meeting:

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Comments or written recommendations for amendments to this Code should be made to:

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2 Petroleum well life cycle

This Code considers the well life cycle stages of:

a) well planning and well design

b) well construction (up to the production wing valve of the well head/ Christmas tree);

c) well evaluation

d) well completion including hydraulic fracture stimulation activities

e) well production and operation

f) well integrity management

g) conversion of petroleum wells to water bores.

h) well suspension

i) well abandonment

2.1 Introduction to petroleum development

There are generally two phases to petroleum development—exploration and production. Wells will be drilled under both phases. The stages of a well's life are outlined in the next section.

Exploration drilling is aimed at identifying hydrocarbon bearing reservoirs. This generally involves a small number of wells targeting a large area. If exploration indicates that hydrocarbon is present pilot wells may be drilled as part of an appraisal program to confirm production potential, to further define reservoir properties and to add reserves. A pilot test is essentially a small-scale production trial, with associated infrastructure.

Once an investment decision is made to progress the project, field development will move to development drilling and production phase. Petroleum wells and the associated infrastructure may operate for up to several decades.

Due to the nature of the reservoirs, unconventional resources (CSG, tight gas, shale gas and shale oil) will typically have more wells over a larger area than a conventional resource. While Queensland has petroleum production from both conventional and unconventional reservoirs, CSG wells make up the majority of producing wells. Typically, these wells are spaced at around 600–1500 m apart.

Once a well is no longer required for petroleum operations, it is plugged and abandoned. Abandoning wells involves:

a) sealing of wells to prevent the intermixing of fluids and pressures between producing formations 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 surface infrastructure as described in legislation.

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

a) Water observation bores to enable impacts of petroleum operations to be quantified.

b) Water supply bores needed for undertaking their activities and those required for 'make good' purposes.

c) Injection bores required for the injection of treated associated water or brine.

d) Water bores converted from a petroleum 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 petroleum operating companies.

2.2 Well life cycle stages

This section is a guideline which outlines the generic stages of a well life. While it makes mention of approvals, the relevant legislation should be consulted to ensure all appropriate approvals are in place.

During the normal course of any drilling or completion/workover 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) rig (drill or workover) and support vehicles

d) water carting

e) specialist testing service providers

f) well site supervision and geological personnel

g) deliveries such as cement, casing or tubing

h) support vehicles/services.

2.2.1 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).

h) Work program issued for well construction

2.2.2 Well construction

a) Site (or lease) preparation in accordance with regulatory approvals and consent conditions

b) Well drilling operations

c) Formation evaluation e.g. logging, coring and testing

d) Running and cementing of casing

2.2.3 Well evaluation

a) Review and analysis of data gathered during drilling

2.2.4 Well completion (including hydraulic stimulation)

a) Well program issued for work

b) Hydraulic stimulation operations (if required)

c) Well completion operations including production tubing and down hole equipment installed

2.2.5 Well production and operation

a) Ongoing production testing, sampling and monitoring as required

b) Workover/intervention activities.

   i. *Planning*

   ii. *Well program issued for work*

   iii. *Well workover operations including modification or replacement of down hole completion equipment and/or production tubing*

2.2.6 Well integrity management

a) Monitoring and maintenance of the well integrity during the operation phase to ensure integrity

2.2.7 Conversion to a water bore

a) Petroleum wells may occasionally be converted to water supply or water observation bores as necessary.

2.2.8 Well suspension

a) Approval to suspend

b) Well suspension or abandonment operations at the wellsite

c) Site rehabilitation activities.

2.2.9 Well abandonment

a) Well program issued for work

b) Well abandonment operations undertaken on site

c) Post-abandonment monitoring undertaken

2.3 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, including landholders, takes place to choose the most appropriate site and consider all other constraints (e.g. access routes, environmental constraints, cultural heritage and landowner constraints). Operators are required to attempt to reach an agreement with landholders when well sites are located on private land.

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 a combination of 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.

2.4 Risk assessment

Operators must carry out a 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.

Sufficient storage for wellsite activities needs to be provided. Tanks or ground pits (or sumps) may be used to hold drilling or waste water. Sumps 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.

2.5 Management of change

Operators must have a management of change (MOC) process covering wells throughout the full life cycle from initial design to final abandonment.

3 Petroleum well requirements

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

Requirements are relevant to all petroleum wells unless otherwise noted in a specific well type section.

3.1 Well records, reporting and notification

3.1.1 Principles

Accurate information, on the entire well life cycle including design, construction, drilling, evaluation, operation, workover, and abandonment, needs to be recorded for future reference. Construction of a water bore has additional requirements under the P&G Act relating to information that must be provided to the Water Act regulator, as well as information outlined under Section 4 of this Code.

3.1.2 Means of compliance

Under the P&G Act a number of mandatory well reporting requirements are stipulated. It is the responsibility of the operator to ensure that these reporting requirements are met. All appropriate documentation which demonstrates compliance with this Code must be completed and submitted with well and bore reports. This includes but is not limited to 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.

In addition to the records which are required to be submitted, operators must keep adequate records to verify conformity to the well design and during the construction process. A record of all work undertaken on a well must be maintained for each well's entire life through to abandoning. Such records will 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) final direction survey
k) core description reports
l) records of all equipment used
m) records of mud chemicals, treatment and workover chemicals used during all well procedures (name, type and volume of each chemical used should be recorded)
n) records of drilling and cementing problems encountered during the well
o) risk assessments
p) well drilling and completion programs including casing running and cementing procedures
q) daily rig reports

r) daily geological reports

s) service company reports

t) down hole and well head diagrams

u) hydraulic fracturing records including fluids and chemicals used

v) workover/intervention records and reports

w) well integrity records

x) abandonment records

3.2 Well design and barriers

3.2.1 Principles

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

All wells must be designed and constructed to ensure the safe and environmentally sound production of fluids by:

a) well objectives being met

b) preventing any cross-flow contamination between hydrocarbon bearing formations and aquifers

c) ensuring that fluids are contained within the well and associated pipework and equipment without leakage. Failure of one barrier must not lead to an uncontrolled release of formation fluids (blowout). It is noted that CSG wells typically have a single barrier between surface and a hydrocarbon bearing zone for portions of its life due to its producing arrangement. Operators must have appropriate processes in place to address this.

d) ensuring zonal isolation between differently pressured permeable formations (e.g. aquifers and hydrocarbon bearing zones) is achieved[1]

e) prevent/avoid the introduction of substances that may cause environmental harm

f) testing and acceptance requirements are satisfied

g) 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.

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

3.2.2 Means of compliance

The design basis for wells are:

a) consider casing setting depths that take into account aquifer and production zone locations, and the requirements for well control

[1] Note: Some formations such as the Walloons Coal Measures, Bandanna Formation or Moranbah Coal Measures are considered as a single entity and do not require zonal isolation within the formation. The regulator should be consulted about other formations.

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 with appropriate casing running procedures. This includes consideration for casing corrosion risk and connection suitability.

d) use appropriate well design and construction materials

e) use appropriate casing centralisation

f) use engineered cement slurries with both appropriate 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

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 and section 3.16.2 is permissible in the following scenarios:

i. when it has been demonstrated, via risk assessment, that there is no natural lift mechanism for hydrocarbons or water to flow to the surface; or

ii. during top hole or surface hole drilling where shallow fluid risk has been assessed as being negligible; or

iii. during diverter drilling; or

iv. during planned underbalanced and managed pressure drilling where surface equipment design limits are not exceeded; or

v. between surface and the hydrocarbon bearing zone for a CSG well during its producing phase. Operators must have appropriate processes in place to address this; or

vi. 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 a minimum 30m above to 30m below the interface must be placed instead; or

vii. in other circumstances during well life cycle activities when a risk assessment has been completed as per the operator's risk management process.

3.2.3 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, operators 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 casing strings.

e) Use sustainable construction practices and operating procedures e.g. to conserve water usage and minimise waste.

f) All 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 liner hangers, 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 zonal isolation.

h) 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.

i) Schematic drawings of well barrier arrangements should be prepared for the well or group of wells of similar well design and architecture.

j) 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.

k) 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.

l) 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.

m) Borehole stability analysis should be considered for all deviated wells >40 degree inclination and for wells in areas known to be prone to well bore instability issues or tectonic activity.

3.3 Casing and tubing

3.3.1 Principles

Casing and tubing must 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 must be designed to facilitate installation of pressure control equipment.

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

The casing programme must 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 must be selected to provide an adequate safety margin between the formation fracture pressure and anticipated pressures during well control and casing cementation operations.

3.3.2 Means of compliance

a) All casing in pressure containing applications[2], casing connections, wellheads and valves used in 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 fracturing), production pressures, potential well control situations, any potential corrosive conditions (H_2S, CO_2, etc.), and other factors pertinent to local experience and operational conditions.

b) Casing and tubing stress analysis must be carried out on all reasonably foreseeable load scenarios that may be imposed on the well. Casing design must consider both uniaxial and triaxial analysis.

c) In all wells, a conductor pipe does not need to meet the requirements under (a), (b) and (c) above.

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

d) Methods of preventing external corrosion that impact well integrity must be considered and implemented where appropriate.

e) Barriers must be installed to prevent surface pollutants from entering the well, and prevent wellbore fluids and gas from escaping to the surface environment.

f) When designing casing strings and casing connections for wells, operators 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.

  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 an operator need to be appropriate for the anticipated well life, service conditions and local experience.

g) All steel 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. Any material other than steel used for casing and tubing must have appropriate manufacturing specifications and verifiable properties.

h) 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 maximum anticipated formation pressure that could occur at surface, but must not exceed the burst pressure rating of the casing with the design safety factor applied.

i) Minimum casing setting depth must 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 must 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.

j) Steel casing connections must be made up to ensure an aligned, round, secure, and leak proof joint.

k) The yield stress of the Oil Country Tubing Goods (OCTG) must be de-rated for temperature.

l) Welded connections are not permitted on any type of well. Seamless and electric-welded pipe is permitted provided it is manufactured in compliance with ISO 11960.

m) If a petroleum well is converted to a water supply bore the surface casing must be adequately set.

3.3.3 Good industry practice

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

b) Typical casing string and connection safety design factors that are to be used 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
Axial collapse	1.30	N/A	N/A

c) For casing run in 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.

d) When making up a casing connection it is important that the recommended torque be applied. 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.

e) The correct use of casing dope, appropriate temperature application, and its impact on torque make-up should be incorporated into casing running procedures.

f) 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.

g) Operators, 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.

h) Long term monitoring and recording of the casing condition should be undertaken.

i) 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.

j) Casing connection qualification testing should be to ISO 13679 based on the intended service.

k) Compression rating of connections should be applied to casing and tubing design as per the manufacturer's recommended values.

l) 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.

m) 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 non-CSG gas wells that cross hydrocarbon bearing or over pressured water zones.

3.4 High pressure, high temperature wells

3.4.1 Principles

For High Pressure, High Temperature (HPHT) wells, a greater awareness of maximum anticipated surface pressures, circulating temperatures, and well pressure control equipment capabilities and readiness must be adhered to.

High temperature is defined as an undisturbed bottom hole static temperature greater than 149 °C (300 °F). High pressure is defined as either the maximum pore pressure of any porous formation that exceeds a hydrostatic gradient of 18 kPa/m (0.8 psi/ft) or needing deployment of pressure control equipment with a rated working pressure in excess of 69 MPa (10,000 psi).

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 pressure 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.

A well may be only high temperature, only high pressure or both high pressure and high temperature. The relevant aspects for a well should be taken into account in its design and construction.

3.4.2 Means of compliance

a) For HPHT wells, 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 operator 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. 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.

3.4.3 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, 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 operator. 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 pressure 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.

3.5 Working with hydrogen sulphide

Hydrogen sulphide (H_2S) is classed as a hazardous substance and a dangerous good. H_2S 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. H_2S 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 H_2S toxicity following inhalation of 600 – 2000 ppm in air, paralyses the respiratory centre and causes breathing to stop.

H_2S is sometimes found in fluids encountered in oil and gas production and gas processing operations. To prevent H_2S entering the wellbore, it is recommended to drill a formation with H_2S with over-balanced drilling fluid. However, some H_2S would still be present in the drilled gas. In addition, Sulphur Dioxide (SO_2) may be present; SO_2 is a toxic product of combustion of H_2S and is normally heavier than air.

3.5.1 Principles

The means of compliance and good industry practices cover any well location where H_2S is expected to exceed 10 ppm (by volume) in the breathing zone.

Detailed information including the effects of exposure to H_2S and associated first-aid response can be found in the Material Safety Data Sheet (MSDS) for H_2S[3] and API RP49, Recommended Practices For Safe Drilling of Wells Containing H_2S.

3.5.2 Means of compliance

a) On exploration or appraisal wells, or where there has been regional evidence of H_2S, 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 H_2S.

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 H_2S environment, an H_2S management plan must be developed. Refer to API RP49, Recommended Practices For Safe Drilling Of Wells Containing H_2S. A H_2S management plan and any relevant emergency response plan must consider landholders and community members.

d) The operator must advise the drilling contractor and service companies involved in well site operations of predicted H_2S levels and temperatures.

e) A flare system must be provided to safely collect and burn H_2S 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 H_2S is predicted, continuous H_2S monitoring equipment must be installed, which is capable of continuously measuring and displaying the concentration of H_2S in ambient air. H_2S gas detectors must be available for personnel working in a known high risk zone when H_2S is present or predicted in any quantity. H_2S 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 is expected to exceed or is 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 H_2S operations, equipment and materials must be selected on the basis of resistance to sulphide stress cracking (SSC) and corrosion where the partial pressure of H_2S 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 H_2S must be resistant at the maximum anticipated temperature of exposure.

j) A drilling fluid program must cater for the use of an H_2S scavenger to remove any H_2S from the drilling fluid.

k) When coring operations are conducted in possible H_2S bearing zones, the wearing of breathing equipment and testing for H_2S 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 H_2S.

l) If H_2S in the gas phase is predicted during well test operations, H_2S concentration must be monitored at first hydrocarbons to surface and at regular intervals throughout the test.

[3] National Pollutant Inventory: Hydrogen Sulphide: http://www.npi.gov.au/resource/hydrogen-sulfide

m) If H_2S 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 H_2S readiness is increased such that operations can continue safely.

3.5.3 Good industry practice

a) H_2S sensors that activate and provide audible and visual alarms when sensing 5 ppm of H_2S 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) H_2S 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 ($ZnCO_3$) to drilling mud will form insoluble zinc sulphide.

d) Prior to penetrating known or predicted H_2S zones, all rig H_2S 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 H_2S should be confirmed by the operator.

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 H_2S should be conducted where safe and practical, and data used for optimisation of future well designs and surface facilities.

3.6 Cementing

3.6.1 Principles

Petroleum 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. Corrosion rates of steel with an adequate cement coating are sufficiently low that cement encapsulation of steel is accepted as a permanent barrier.

f) Provide axial support for the casing string to permit further drilling and to provide an anchor for BOP equipment

g) Reduce possibilities of casing buckling and/or collapse, particularly in situations where abnormal formation stresses occur

h) Seal off to the casing shoe, or equivalent, in order to control pressure.

3.6.2 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 must consider that after abandonment, two adjacent cement barriers across all aquifers will be required as per the relevant section of this Code.

iii. Testing pressures must take into account collapse pressure of the inner casing string and fracture gradient at the outer casing shoe.

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.[4]

c) 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. Pressure testing of casing (unless conducting a green cement pressure test on bump) or drilling out the shoe track for a subsequent hole section – must, as a minimum, have achieved a minimum compressive strength of 500 psi (3.5 MPa) based on the laboratory testing time for cement surrounding the casing shoe.

d) 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 cement slurry meets the requirements of the well design (refer Table 2).

i. In the case where a number of similar wells are drilled or abandoned 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.

ii. The testing, as a minimum, must include slurry density, rheology, thickening time, free water, fluid loss (if required), fluid compatibility (cement, source/mix water, drilling mud, spacers used), mechanical properties and compressive strength development with time.

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

Table 2: Cement criteria

Property	Primary cement criteria
Density	• 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)	• Top of cement to comply with barrier requirements set out in the relevant section 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 *Water Act 2000.*

e) Free water content of the cement must be specified as less than 2% using the free water test outlined in API RP 10B-2. Based off this requirement being met calcium chloride or other chloride-based accelerants can be used.

f) 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).

g) 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.

h) Operators must ensure that the appropriate cement slurry for fracture stimulation be placed at least 150 m above the shallowest target reservoir to be hydraulically fractured. For wells with the top target reservoir shallower than 150 m the appropriate cement slurry for fracture stimulation must be placed to surface.

Refer: API Guidance Document HF-1

i) 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.

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 an appropriate wiper plug assembly be used for production casing to enable plug bump and pressure test of the casing before cement cures.

n) The operator must have a verification procedure for primary cement jobs.

o) If surface casing is set shallower than 60 m true vertical depth, the next casing string (intermediate or production casing) must be cemented to surface.

p) The operator must provide notice to the Chief Inspector if:

   i. The operator cannot verify that achievement of primary cementing objectives can be reliably demonstrated by utilising at least three of the verification methods described in Table 3; or

   ii. The operator cannot reliably demonstrate achievement of the primary cementing objectives once final pressure tests and/or wire-line evaluation are complete; or

   iii. The operator is unsuccessful in the initial attempt of a remediation of a primary cement job.

   The way in which to give the notice is by:

   - Submitting the notice using the online system made available on a Queensland Government website for the purpose; or
   - Lodging the notice at the office of the Chief Inspector.

   Notice must be submitted as soon as reasonably practical (but no later than 5 business days) after the initial problem arises.

Specific well type requirements – CSG wells

q) To prevent interconnection between zones of differing pressure and water quality:

   i. 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.

   ii. 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.

Specific well type requirements – Other wells

r) To prevent interconnection between zones of differing pressure and water quality:

   i. 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. In wells in which it will take greater than 36 hours to reach a compressive strength of 500 psi at surface conditions, than 36 hours wait time can be used.

Table 3: Verification and evaluation methods for primary cement jobs

Completion Type	Verification Criteria	Contingency
Requirements which cover both casing and liner completions	• Slurry mixed and placed in accordance with contractor approved cementation procedures and the cement job pressure charts show pressure rise during cement displacement in line with expectations. • 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. • An appropriate cement integrity test such as a formation integrity test (Operators must have a clear understanding of the difference between a FIT and a LOT and the test's suitability in the specific circumstance e.g. in CSG wells, with a shallow casing shoe, it may be undesirable to initiate formation fracture during a cement integrity test and so a FIT and not a LOT should be used). • Appropriate cement evaluation log	• Where the verification is inconclusive, the extension of good quality cement above the shoe, above hydrocarbon bearing zones or aquifers must be verified by appropriate cement evaluation tools, interpreted by a competent person.
Additional liner only requirements	• Pressure test of liner top packer must be performed and recorded to verify zonal isolation has occurred after all the cement has reached a compressive strength of 500 psi. Testing pressures must be no less than 500 psi over the previous casing leak off test at the shoe.	• If a failed pressure test occurs on bump, set liner top packer, circulate out excess cement and WOC prior to conducting pressure test again. • If the pressure test fails again, may opt to run a liner tie back packer on top of the liner top and re-test.

3.6.3 Good industry practice

a) Operators should ensure proper wellbore preparation, hole cleaning and conditioning prior to the cement job. Once casing has been run to landing depth, operators 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 job design should include proper cement spacer design and volume to ensure 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.

d) 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.

e) Water and cement slurry samples should be taken (periodically during each cement job) by the operator'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 with results appropriately recorded in reports.

f) 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). There may be instances after repetitive success has been shown, such as when a new cementing provider is used or a new design is implemented, that cement bond log evaluation should take place. The additional cement bond log requirements for wells that are to be hydraulically stimulated should be noted.

g) Leak-off tests (LOT) or formation integrity tests (FIT) 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.

h) Operators 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.

i) 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.

j) Verification and evaluation recommendations for primary cement jobs are outlined in Table 3.

k) Cementing slurry design considerations should include those outlined in Table 4.

Table 4: 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). It is noted that in CSG wells it can be typical to include additives in order to create a thixotropic slurry to prevent formation damage.
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).

Specific well type requirements

l) 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.

m) 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.

3.7 Aquifer isolation

3.7.1 Principles

Protection of aquifers is an integral consideration in well design and must be adhered to.

3.7.2 Means of compliance

a) Aquifers must be considered during the well design process and operators must include the design of aquifer isolation in the well program.

b) Operators must ensure casing setting depth is selected to protect resources such as aquifer systems.

c) Operators must ensure cementing design and verification is carried out as per the requirements of this Code.

d) Top of cement must comply with well barrier requirements set out in this Code.

e) Monitoring of barriers and casing condition must be carried out as per the operator's well integrity management system.

f) For wells in the Great Artesian Basin (GAB), all groundwater units, as identified in the Water Plan (Great Artesian Basin and Other Regional Aquifers) 2017 must be isolated from each other by primary cementing. Each groundwater unit is comprised of geological formations which may or may not be aquifers or permeable hydrocarbon bearing zones. Aquifers and permeable hydrocarbon bearing zones within a groundwater unit must be isolated from each other by primary cementing unless it can be proven that they were in hydraulic communication prior to the well being drilled. The abandonment section of this document details relevant isolation requirements.

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) If primary cementing fails to achieve the isolation objectives stated in points (f), (g) and (h) above then remedial cementing is required.

j) For areas not covered by the GAB or Cooper Basin requirements where potential new aquifers have been identified, information must be brought to the attention of the Chief Inspector via gassafe@dnrme.qld.gov.au.

3.7.3 Good industry practice

a) Operators should refer to API Standard 65-2, Isolating Potential Flow Zones during Well Construction.

3.8 Wellheads

3.8.1 Principles

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

a) ensuring well integrity at surface

b) supporting casing and completion tubing strings by provide a suspension point

c) supporting the BOP during the drilling phase, and the wellhead Christmas tree during the production phase for containment of fluids

d) providing the arrangement for sealing, testing, monitoring, injecting into, and bleeding off between annuli.

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.

3.8.2 Means of compliance

a) Operators must monitor wellheads for leaks or emissions in accordance with the separate Code of Practice for this purpose. This document is available on the Queensland Government website.

b) Wellhead equipment and running tools must be specified in accordance with API Specification 6A/ISO 10423 and NACE MR0175/ISO 15156.

c) 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.

d) Side outlet valves must be rated to at least 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.

e) Wellheads for high temperature wells must include design for lock down of hangers, rated for the well conditions.

f) Casing to wellhead pressure tests ('P' seal area or equivalent) must not exceed 80% of the collapse rating of the casing.

g) Any change of usage of a wellhead (i.e. to incorporate gas lift or re-injection) must be fully risk assessed by the operator to ensure the compatibility of the existing equipment with the proposed usage.

3.8.3 Good industry practice

s) 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.

t) Operators 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.

Specific well type requirements

u) 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.

3.9 Well control

3.9.1 Principles

Well control aims to reduce hazards when drilling a petroleum well and must be considered at all times. The primary purpose of well control is to provide barriers to prevent uncontrolled release of formation fluids to surface. Well control for an overbalanced approach can be defined as:

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 well. If the well begins to flow, appropriate pressure control equipment (e.g. BOPs, diverter) will be in place to contain any influx of formation fluid and allow it to be appropriately handled e.g. safely circulated out of the well.

The requirements for well control systems will vary when underbalanced or managed pressure 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.

3.9.2 Means of compliance

a) Operators must address well control in safety management systems. Operators must have a well control standard document available at well sites, detailing requirements for equipment level, kick detection and well control techniques.

b) During well construction, operators must install well pressure control equipment (e.g. BOP stack and wellhead) for all operations after the installation of the surface casing. Well pressure 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) Operators must use pressure control equipment compliant with API Specifications 16A, 16C and 16D.

d) The level of pressure control equipment required on any operation, and the configuration employed, must be suitable for the well, the subject of a risk assessment and documented accordingly.

e) Operators must function and pressure test pressure control equipment in line with API Standard 53, including drill through equipment, choke and kill line systems and pressure storage systems (e.g. accumulators).

f) Operators must utilise best industry practice, as appropriate for the well type, for early identification of fluid influx (well kick). This must include, but is not limited to, monitoring of mud pit level, flowline flow rate and trip volume sheets derived from trip tank measurements.

g) Operators must consider DNRME Technical Guidance - Surface Gas Handling System and Mud Gas Separator Design Principles for Petroleum Drilling Operations to ensure that the surface gas handling system for drilling operation is fit for purpose and used within operating limitations. To control an influx, well bore fluids must 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. For lower pressure, lower rate wells (e.g. appropriate CSG wells) 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 must 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 Safety Regulation.

j) For hydrogen sulphide applications, all well pressure control equipment must meet the requirements of NACE MR0175/ISO 15156 Specifications for H_2S Operations.

k) Working temperature rating for well pressure control equipment must meet the maximum anticipated continuous exposure temperature for rubber/elastomer components.

l) All well pressure control equipment, including connections, valves, fittings, piping etc. (excluding annular BOPs) must be rated to exceed maximum anticipated shut-in surface pressure.

Specific well type requirements – other wells

m) A gas detection system must be used on the well site to identify hydrocarbon bearing formations and potential gas influx.

3.9.3 Good industry practice

a) Additional guidance for selection and use of well pressure control equipment 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 should be conducted to train involved personnel in detection, prevention and recovery of a lost barrier.

Specific well type requirements – CSG wells

e) A gas detection system should be used on the well site to identify hydrocarbon bearing formations and potential gas influx.

3.10 Fluids

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 majority of onshore wells in Queensland 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.

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 must ensure that all risk assessment, well design, operational and crew training considerations are addressed prior to and during execution of the project.

Fluids other than used for drilling (e.g. hydraulic fracturing, suspension and abandonment fluids) have additional requirements in this Code in other sections.

3.10.1 Principles

The primary objectives for drilling and completions fluids are to:

a) Maintain primary well control as per the well barrier requirements

b) Optimise hole conditions for the retrieval of quality geological and reservoir data

c) Minimise reservoir damage and therefore optimise well productivity

d) Improve drilling performance, thereby reducing overall well costs.

Drilling fluids and additives are regulated under the environmental authority issued under the *Environmental Protection Act 1994*, as they are classed as contaminants. When selecting drilling fluids, the impacts to health and safety of personnel and damage to the environment must be minimized.

3.10.2 Means of compliance

a) Fluids must be selected and managed to ensure all products used in all stages of the well’s life cycle (e.g. drilling, completion, workover, suspension, abandonment) are used in accordance with the manufacturer's recommendations and relevant material safety data sheets (MSDS).

b) The name, type and quantity of each chemical used on each well throughout the well construction, operation and abandonment process must be recorded.

c) Operators must ensure that drilling operations through local aquifer systems are always undertaken using water or water-based mud systems until cased off and isolated.

d) 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.

e) Where H_2S 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 H_2S contamination), high pH can be used to hold the sulphides in the mud

ii. sufficient Zinc Carbonate ($ZnCO_3$), Zinc Oxide or Ironite Sponge must be available to treat a fluid system containing up to 500 ppm H_2S.

Specific well type requirements – other wells

f) The operator must carry out testing of the active drilling fluid in accordance with API RP 13B a minimum of twice per day.

3.10.3 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) Operators 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 operations (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 to health, safety and 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) Operators should use established, effective drilling practices to achieve a stable, uniform and, as far as possible, in-gauge hole.

h) Biocide, oxygen scavenger and/or corrosion inhibitor should be considered for all water based systems.

i) Drilling fluid should be captured and recycled for reuse as much as practical.

j) 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.

k) 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.

l) To maintain accurate volume accounting, fluid transfers should not be made from or to 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.

Specific well type requirements – other wells

m) The operator should specify minimum stock of contingency barite on location for the particular well type (exploration, development, HPHT).

n) 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.

3.11 Evaluation, logging, testing and coring

In petroleum exploration, appraisal and development, formation evaluation is used to characterise the entire subsurface environment including the reservoir, aquifers, formation fluids and determine the ability of a borehole to produce petroleum. The main evaluation data is typically gathered with wireline logging tools or logging-while-drilling (LWD) tools. The types of logs that are run in a well are selected by geologists, petrophysicists and other specialists at the time the well is designed. Common logging tools used for evaluation of wells include natural gamma ray, density, calliper, resistivity, sonic and image logs.

Logging produces valuable information, to determine the nature and type of strata encountered. This information is used in optimising production, artificial lift design, future well design and drilling operations. In addition, it allows 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.

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

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

a) predicted reservoir fluids (oil, gas, H_2S, CO_2, water, etc.)

b) reservoir temperatures and pressures

c) objectives of the test

d) potential for solids production

e) predicted flow rates and productivity.

3.11.1 Principles

Relevant logging, testing and coring must be carried out as per legislative requirements. This includes appropriate analysis and interpretation of results.

Cuttings samples, core samples, fluid samples and other samples from the petroleum well drilling process must 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.

3.11.2 Means of compliance

a) Operators must ensure that relevant requirements stipulated in the P&G regulations are carried out, such as:

   i. an accurate down hole survey using appropriate techniques.

   ii. samples of formation cuttings, cores and fluid samples to be kept.

   iii. appropriate equipment on hand that can recover survey or logging equipment lost down hole.

b) Well testing requirements (for wells that will not flow to surface only the relevant requirements are applicable):

   i. Well test programs must be prepared. For all DSTs a well and 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 and cross-overs).

   vii. Emergency response procedures must be in place.

c) Local regulations must be reviewed and followed for the management and transportation of explosives.

d) The operator 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.

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) 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

3.11.3 Good industry practice

a) Where appropriate (e.g. when hole conditions and pressure regimes dictate), operators 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.

3.12 Hydraulic stimulation

3.12.1 Principles

Hydraulic stimulation is conducted to improve recovery of hydrocarbons. The underlying principles are:

a) To ensure protection of aquifers is maintained during all operational 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.

3.12.2 Means of compliance

a) During the well design and planning process, operators must identify any aquifers at risk of being impacted by hydraulic stimulation operations.

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 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) Wells that are to be hydraulically stimulated require evaluation of cement bond quality using appropriate cement evaluation tools. Cement bond log evaluation must 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). If there is a material change after repetitive success has been shown, such as when a new cementing provider is used, there are issues in the cement job/s or a new design is implemented, then cement bond log evaluation must take place again until repetitive success of slurry design and cement placement.

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, flow-back or produced fluids must be recovered and managed as per approved regulatory practices.

3.12.3 Good industry practice

a) Stimulation design should take into account location of known faults.

b) Operators 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 program(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) Operators should refer to API Guidance Document HF1, Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines.

3.13 Well integrity management

Well integrity ensures containment and prevents the escape of fluids to subsurface formations or the surface. The typical scope of a Well Integrity Management System (WIMS) is shown in Figure 1. The relevant well integrity standards, such as ISO 16530-2 and NORSOK D-010, should be consulted when compiling a WIMS.

3.13.1 Principles

Monitoring and maintenance is required to preserve the well in a suitable condition for its useful life. Well Integrity Management Systems 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.

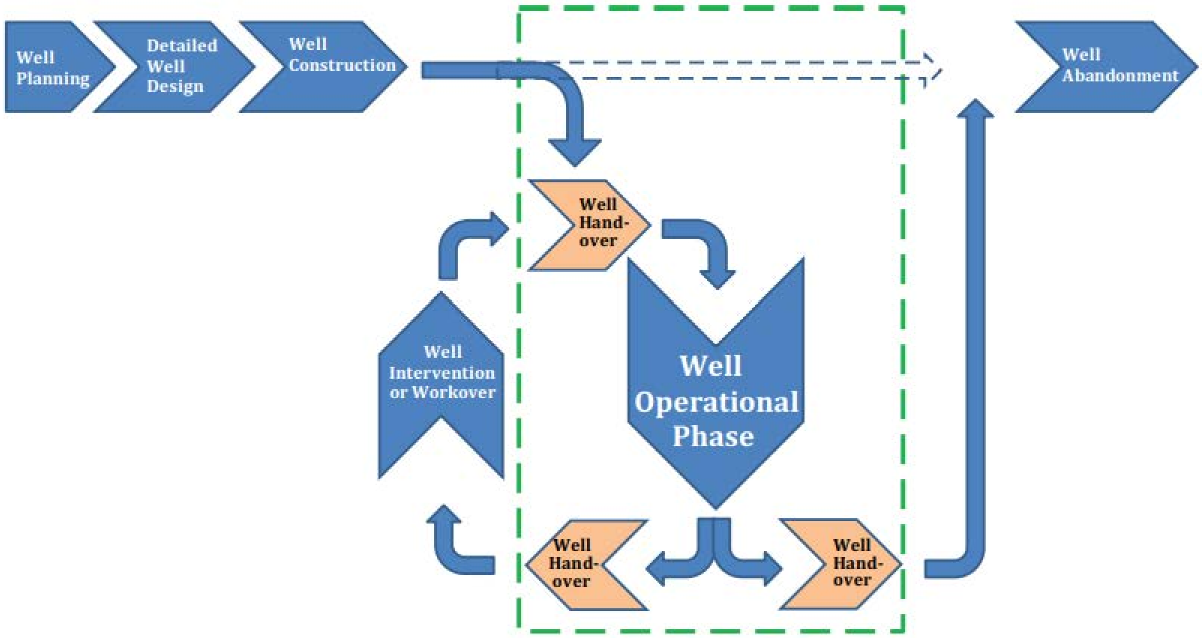


Figure 1: Illustration of the scope of the well integrity management system

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

3.13.2 Means of compliance

a) The operator 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 operator is responsible for ensuring maintenance of current documented records, which clearly state the existing risk level of wells and any other observations related to well integrity. The records must 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.

e) If a well integrity issue is discovered and at a minimum one barrier has severely degraded or failed and the issue is not readily replaceable (a leaking valve at surface is readily replaceable) such that the well risk level as per the WIMS increases to require additional monitoring and/or corrective action (this does not include waiting for the next planned maintenance to occur to fix the issues), the operator must provide notice to the Chief Inspector. If a well integrity issue is reported via another reporting requirement (e.g. leak management or cementing notifications) then the reporting requirement within this section is taken to have been met. The way in which to give the notice is by:

   i. Submitting the notice using the online system made available on a Queensland Government website for the purpose; or

   ii. Lodging the notice at the office of the Chief Inspector.

   Notice must be submitted as soon as reasonably practical (but no later than 5 business days) after a barrier failure has been identified by the operator or after the operator has completed a fitness for service assessment on the barrier in question.

3.13.3 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.

c) 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.

3.14 Workover and intervention

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 tubing or a pump, testing pressure seals and measuring or logging well parameters such as flow rates and temperatures in the well, fluid sampling and pipe integrity.

3.14.1 Principles

Workovers and interventions must be design and implemented to meet relevant industry standards.

3.14.2 Means of compliance

a) The operator must ensure well barriers are in place to intervene on the well and if necessary risk assess any deviations.

b) The operator must use fit for purpose well design and construction materials as dictated in this Code.

3.14.3 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, 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 for recovered equipment 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 recorded prior to handover of the well back to production or abandonment.

3.15 Well suspension

Well suspension applies to a shut in well which has additional requirements as defined by an operator's well integrity management system due to the length of shut in time.

3.15.1 Principles

There must be appropriate consideration in management systems for wells that are suspended for significant periods of time. This includes wells that are unlikely to return to production or have not returned to production for a significant period. While the shut-in timeframe is dependent upon numerous factors that must be considered in the operator's well integrity management system, it is expected to be in the order of 2 to 5 years.

The primary considerations for suspension of a 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.

The following matters must be considered when suspending a well:

d) the construction characteristics and integrity history of the well including the integrity of the cement columns

e) geological formations encountered

f) potential loss zones

g) hydrogeological conditions i.e. aquifers

h) environmental risk

i) regulatory requirements, title conditions and industry standards

j) perforated and hydraulic fracture stimulated zones.

3.15.2 Means of compliance

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

   i. during re-entry, workovers and other maintenance work

   ii. during temporary suspension of open hole sections due to weather or other operational reasons such as batch operations.

b) Suspended wells must be appropriately classified and addressed in an operator's well integrity management system.

c) Appropriate suspension fluids must be used. Water-based fluid mixed with biocide, oxygen scavenger and/or corrosion inhibitor must be used in the wellbore in-between or above isolation plugs.

3.16 Well abandonment

This section has been developed primarily to support operators in the abandonment of petroleum 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.

3.16.1 Principles

Petroleum 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.

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 operator but need qualification so that they can be considered permanent barriers.

The well abandonment objectives are to ensure:

a) Isolation of aquifers from each other and from permeable hydrocarbon zones

b) Isolation of permeable hydrocarbon zones from each other unless commingling is permitted

c) permeable formations containing fluids at different pressure gradients and/or significantly different salinities are isolated from each other to prevent crossflow

d) there is no pressure or flow of hydrocarbons or fluids at surface both internally in the well and externally behind all casing strings
e) 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
f) The site is left safe and free from contaminants.

The following matters must be considered prior to well abandonment:

g) the construction characteristics and integrity history of the well including but not limited to:
    i. sustained pressure/flow on casing annulus
    ii. confirmation of cement tops where cement returns where not achieved
    iii. integrity of cement columns
    iv. casing integrity
    v. fish stuck in hole.
h) geological formations encountered
i) potential loss zones
j) hydrogeological conditions i.e. aquifers
k) environmental risk
l) regulatory requirement, title conditions and industry standards
m) perforated and hydraulically fractured zones.

3.16.2 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 must 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 liner[5] that is not made of steel, including for example, a slotted PVC liner.
d) Cement must be used as the primary sealing material. Cement testing must be carried out as per requirements set out in Section 3.6 of the Code.
e) Water-based fluid mixed with biocide, oxygen scavenger and/or corrosion inhibitor must be left in the wellbore in-between cement plugs if the plugs are not in immediate contact.
f) For wells in the Great Artesian Basin (GAB), all groundwater units, as identified in the Water Plan (Great Artesian Basin and Other Regional Aquifers) 2017 must be isolated from each other by a minimum of two barriers. Each groundwater unit is comprised of geological formations which may or may not be aquifers or permeable hydrocarbon bearing zones. Aquifers and permeable hydrocarbon bearing zones within a groundwater unit must be isolated from each other by a minimum of two barriers unless it can be proven that they were in hydraulic communication prior to the well being drilled.[6]

[5] 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.
[6] Exceptions from the two barrier requirements stipulated here are listed in Section 3.2.2.

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 a minimum of two barriers. The SEO clearly identifies formations designated as aquifers for management.[6]

h) 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.[6]

i) 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.

j) Prior to conducting the 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.

k) Sucker rods, pumps and tubing (unless used as a sacrificial stinger) and any other debris in the well or bore that can practicably be removed are removed.

l) For pre-existing mineral exploration drill holes (i.e. legacy boreholes) that are fully uncased, the open hole must be cleaned out down to TD or Hang-Up-Depth (HUD) and fully cemented to surface.

m) A 50 m weighted high-vis pill must be spotted below each cement plug that is not set directly above a physical barrier (hole bottom is included as a physical barrier) and where there is any potential for losses below the cement plug i.e. any open section.

n) Cement plugs must not exceed 200 m in length unless installed with coil tubing or sacrificial stinger.

o) A surface cement plug minimum 10 m in length must be placed at the top of the inner most 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 are to be established below the surface cement plug. If the top of surface cement plug is less than 10 m below the surface the casing can be topped up with cement.

p) 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.

q) 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

Section 3.16.3 *Cement plug requirements and verification methods* of this Code provides generalized diagrams depicting how abandonment barrier requirements may be met as described in this section.

r) Cement plugs for decommissioning must meet the minimum requirements as detailed in Section 3.16.3 *Cement plug requirements and verification methods* of this Code and consider the following:

   i. The preferred method where possible is to cement the inner casing string to surface while noting the recommended maximum plug length and the requirement for a surface cement plug.

   ii. A mechanical barrier (e.g. bridge plug) may be used in appropriate situations as a support to set a cement plug on top of it. If a mechanical barrier is used it must be set as close as is practicable above perforations. When a mechanical barrier is used, it or the cement plug directly above it must be verified by tagging it with a minimum 5000 lb set down weight and pressure tested to 3.5 MPa (500psi) above the estimated (or previously recorded) leak off pressure (within the limits of the casing and wellhead pressure ratings).

   iii. Consecutive stacked cement plugs set inside casing do not require additional tagging or pressure testing provided the initial base is verified appropriately i.e. the lower most cement plug of the stack is appropriately verified, or the mechanical barrier set is appropriately verified, or the well bottom has been tagged. Verification of the stacked cement plugs above the bottom plug may be completed via the post job cement report and appropriate calculations.

   iv. If using a sacrificial stinger to set open hole plugs, provided no losses observed during cement placement then no tag is necessary. This assumes the open hole plug is not set off bottom.

   v. For a final surface cement plug extending from ground level, the top of cement must be visible and at surface. A shallow set plug is not considered a permanent barrier given the very low formation pressures at ground level. Well barriers must be established and verified with the plugs below the surface cement plug.

   vi. If unable to achieve the required 5000 lb 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.

s) 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.

t) 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

u) 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.

v) Wellheads must be removed, and the casing string(s) must be cut at a minimum of 1.5 m below surface.

w) The well must be capped below the surface with a marker plate made of appropriate material 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 the top (vented/ported plate). The marker plate must be installed as per the following requirements:

   i. the unique 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.

   Marker tape is to be laid approximately 20cm above the top of the casing.

x) An appropriate plaque, that states the following information, is placed on surface on a fence post, building or other permanent structure nearest to the borehole:

   i. the unique 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

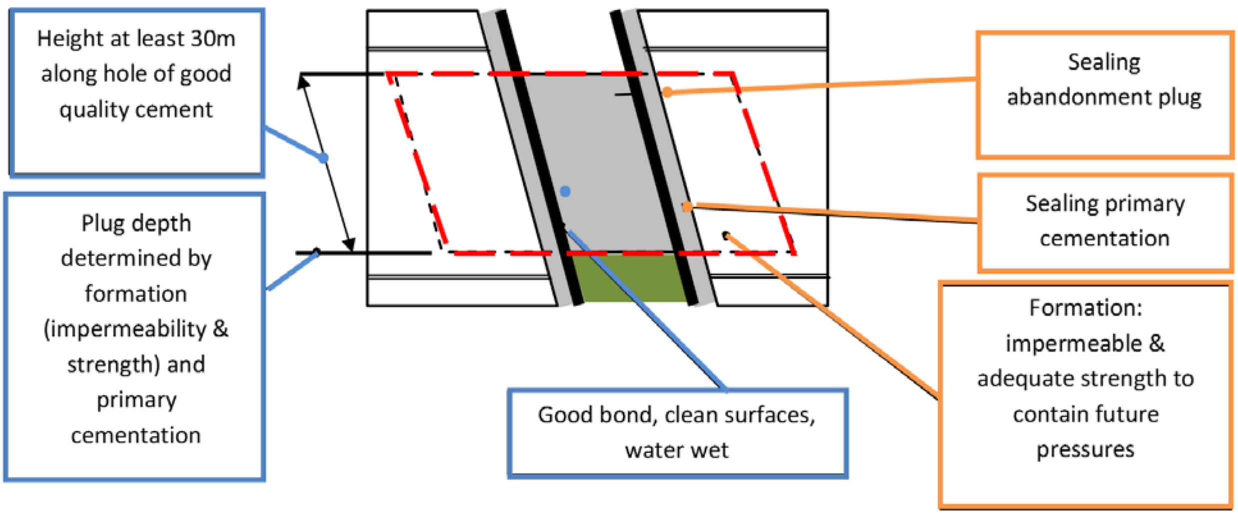
   iv. the distance and direction to the bore or well from the plaque (if the plaque is not located directly over the well).

   A post cemented in place on top of the well location is the preferred option but may not be practical for the landowner. It is the operator's responsibility to locate this plaque so it is in an appropriate place after hand back to the landowner.

y) 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.

3.16.3 Cement plug requirements and verification method

Figure 2: Cement encased casing - well barrier



Legend for figures 3 to 9

(yellow)	cement
(light blue)	appropriate abandonment fluid and/or additional cement
(green)	high-vis pill (sections below plugs with high-vis plugs could also be filled entirely with cement to provide a solid base)

Figure 3: Open hole/ uncased hole section (no lost circulation and not approved for commingling)

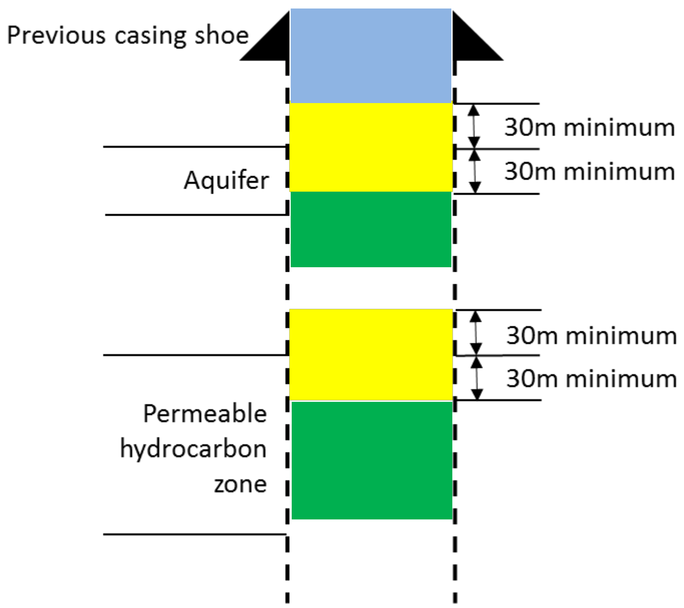


Figure 4: Cased hole section

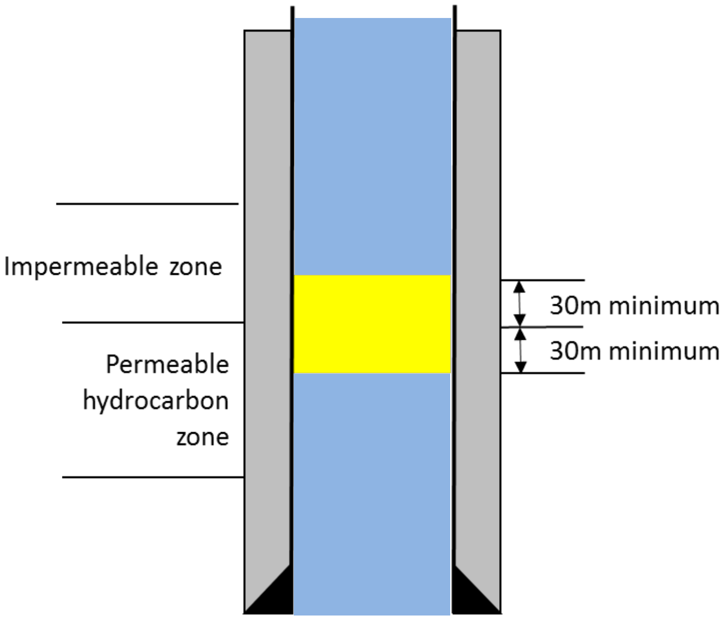


Figure 5: Casing shoe or equivalent with open hole/un-cemented liner below

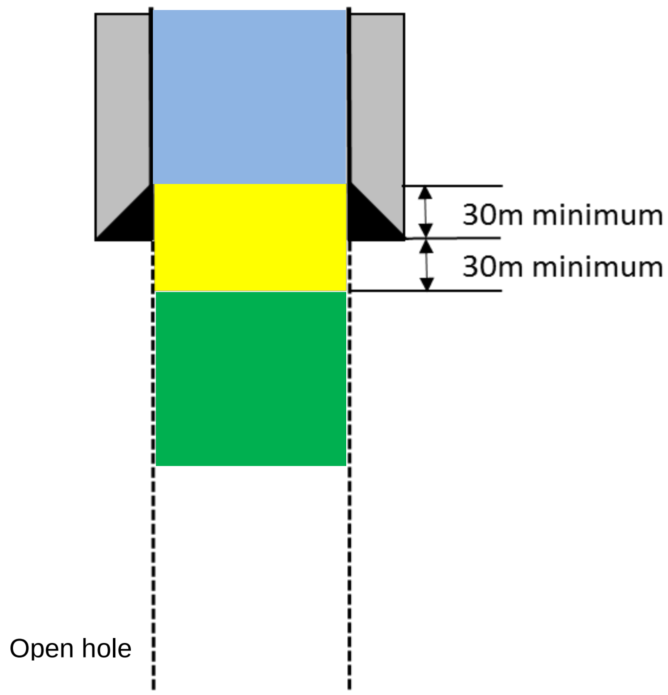


Figure 6: Casing shoe with open hole below (with lost circulation) or casing shoe with uncemented liner below

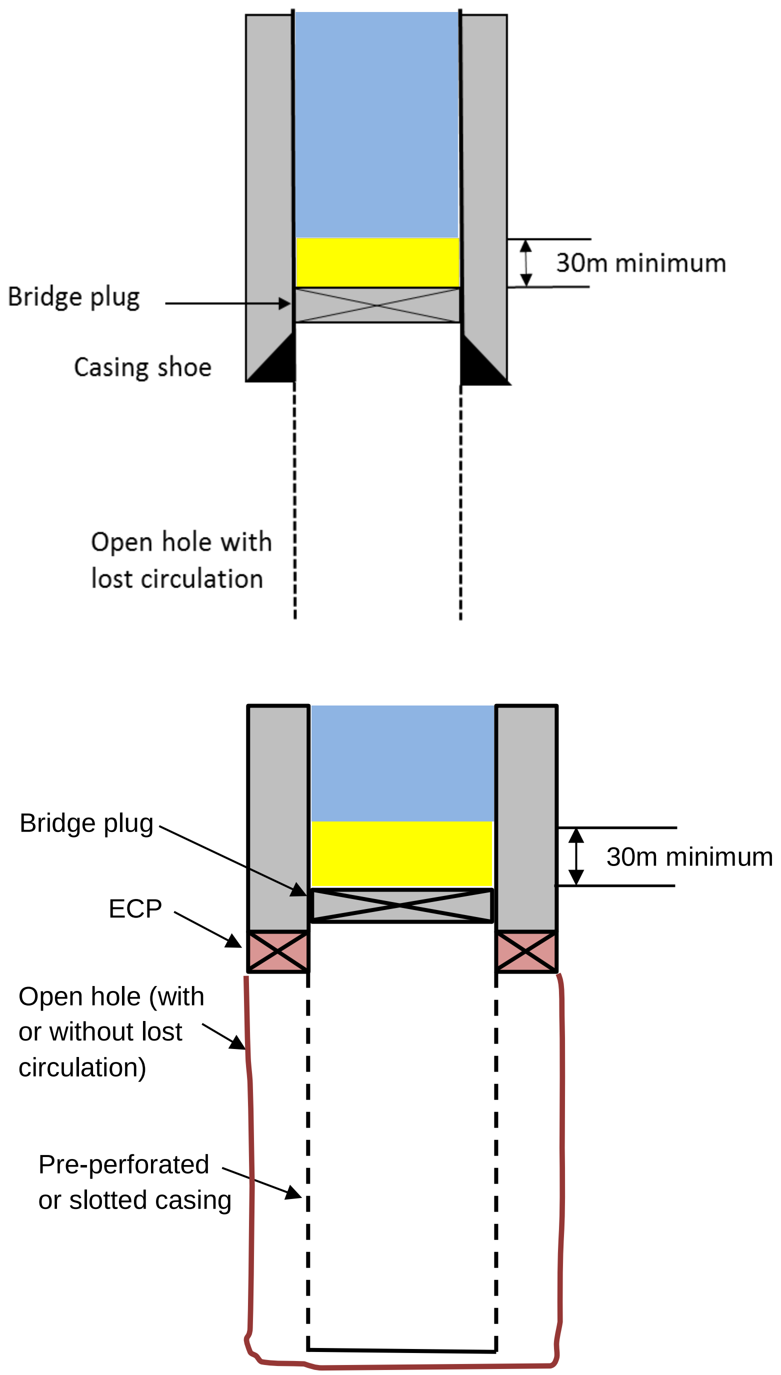


Figure 7: Cut and recovered casing/liner

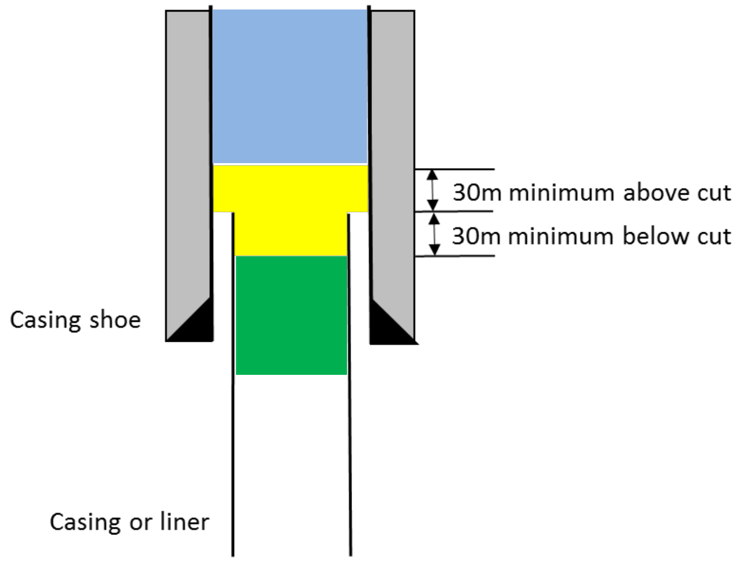


Figure 8: Perforated casing

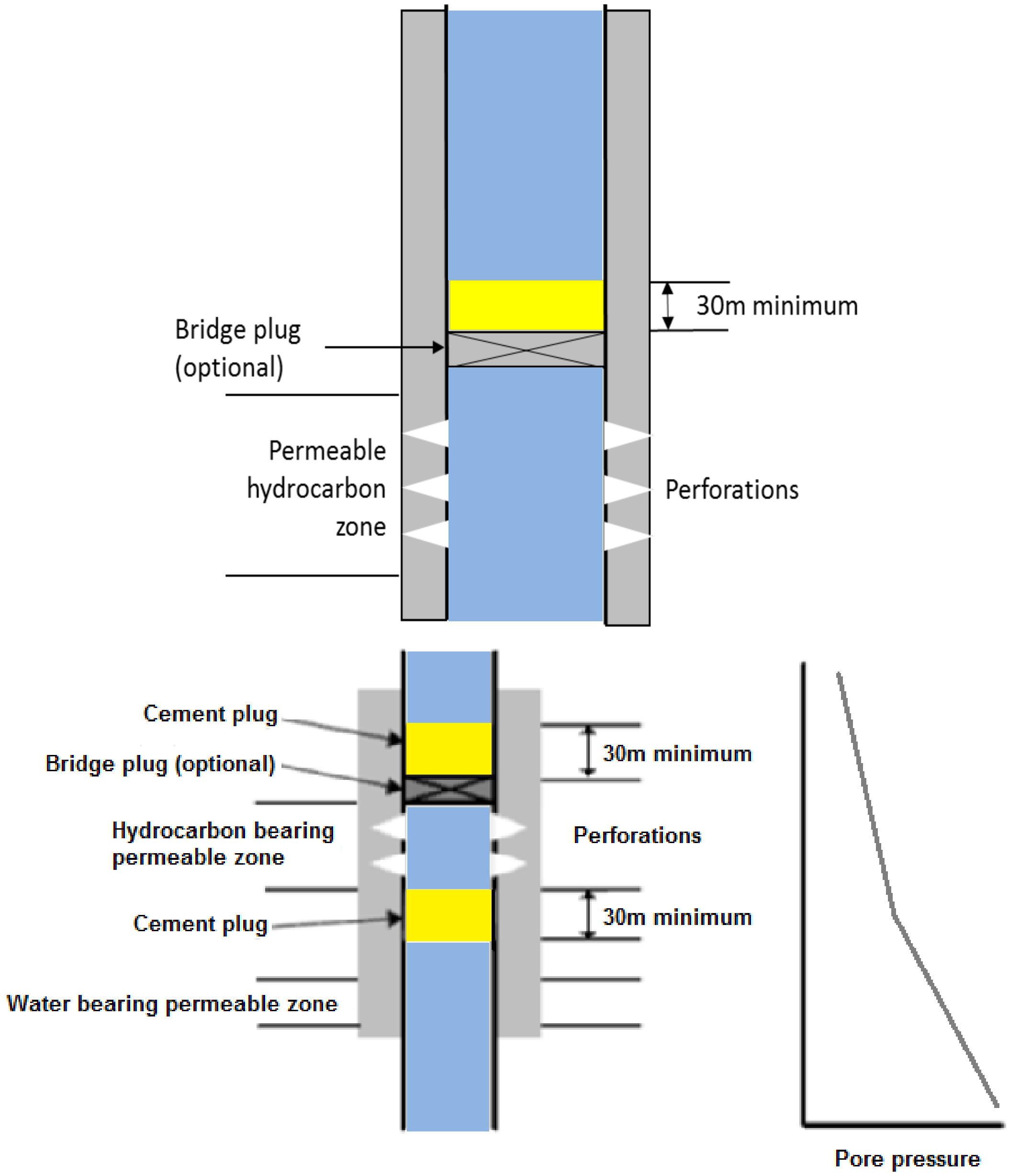
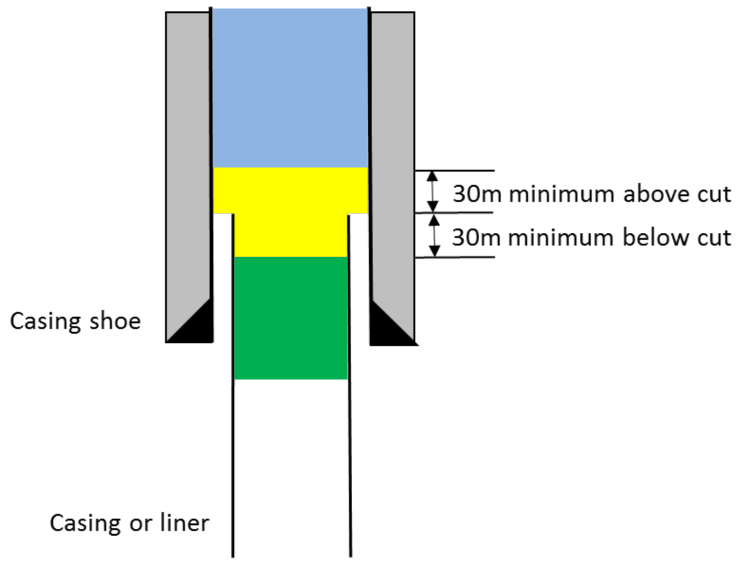


Figure 9: Production liner laps



Completion type	Requirements
Open hole/uncased hole section	• Off bottom open hole cement plugs to be verified by tagging the plug with a minimum 5000 lb (2270 kg) set down weight. • 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.
Cased hole section	• For a cased hole cement plug barrier that is either unsupported or supported by a high-vis pill and not exposed to open reservoir below, verification to be done by tagging the plug with a minimum 5000 lb (2270 kg) set down weight. • 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.
Casing shoe or equivalent with open hole below	• 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. • 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) set down 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).

Casing shoe or equivalent with open hole below (with lost circulation) or casing shoe or equivalent with uncemented liner below	• Where lost circulation conditions exist or there is open hole behind casing/liner below the shoe, a mechanical barrier may be set as close as is practicable above the casing shoe with at least a 100 ft. (30 m) cement plug set above the mechanical barrier, adjacent to good annulus cement (only applicable if co-mingling is allowed[7]).
Cut and recovered casing/liner	• Cement plug must be verified by tagging the plug with a minimum 5000 lb 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). • 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.
Perforated casing	• A mechanical barrier with cement on top may be used. • For a cased hole cement plug exposed to open perforations below, verification to be done by tagging the top of the first cement plug extending above the perforations with a minimum 5000 lb 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). • Verified cement plugs must be placed to provide cement coverage to at least 30 m above perforated intervals. • Verified cement plug must be used to isolate perforated intervals of different pressure regimes, as per regulatory requirements. If co-mingling is allowed, a plug placed above the perforated intervals is sufficient.
Production liner laps	• A cement plug barrier must be set across each liner top in the form of a T-plug with at least 100 ft. (30 m) of cement below and at least 100 ft. (30 m) of cement above liner top. • Cement plug must be verified by tagging the plug with a minimum 5000 lb 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 aquifer isolation in Surat Basin abandonments for wells using an external casing packer.

[7] Note: Some formations such as the Walloons Coal Measures, Bandanna Formation or Moranbah Coal Measures are considered as a single entity and do not require zonal isolation within the formation. The regulator should be consulted about other formations.

3.16.4 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) When placing a plug, excess cement should be used 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.

h) 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.

i) Balanced cement plug volumes pumped should incorporate allowances for open hole and cased hole contamination.

j) 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.

4 Additional and alternative requirements for water bores

4.1 Introduction

This section 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 section is based on standards and guidelines from the third edition of the Minimum Construction Requirements for Water Bores in Australia (MCRWBA), and on the Minimum Standards for the Construction and Reconditioning of Water Bores that Intersect the Sediments of Artesian Basins in Queensland (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 section 3 of this Code

   ii. provisions of section 3, plus alternative details provided under Section 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 section 3 of this Code.

c) Details for conversion of a petroleum well to a water bore under s.283 of the P&G Act are provided in section 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 Section 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 MSWBIAB.

c) Water bores constructed or through conversion under this Code require a drill log form, located on the Queensland Government 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 must:

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:

d) slotted or perforated casing

e) screens

f) 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/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 section 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 must be installed so that the top of the casing is above flood level where practicable. Tongue type valves (gate valves) must 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 4.2.1 (b) (ii) of this Code. Where this assessment shows headworks need not comply with specifications in section 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 CO_2.

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 petroleum wells to water bores

4.9.1 Principles

Conversion of a 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 petroleum well is defined under the P&G Act. Only wells that can be demonstrated to have met as a minimum, all the requirements of the construction and abandonment code (either previous or current revisions), 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 petroleum well, constructed in a corrosive area, must not be converted to a water bore unless it meets the requirements of section 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.

c) Before conversion and transfer of a well to a landowner, or transfer of a purpose built water bore to a landowner the operator must ensure that the location of the bore allows for the proposed take through to be permitted under relevant licensing regulations. It is recommended that DNRME be contacted to confirm this.

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. It is noted that based on the definition of an aquifer, a permeable hydrocarbon bearing zone may also be defined as an aquifer. Typically, in the area of a permeable hydrocarbon bearing zone that is being developed such a formation will not be used as a water source.
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 provide a seal between casing and the walls of the wellbore. It is also used in abandonment operations. Different specifications of cement are used for different purposes. Cement may 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.

Term	Definition
Cementing head	Component fitted to the bore for the use of cementing.
Cement plug	Portion of cement placed at some point in the wellbore.
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.
CIT	Cement integrity test. A pressure test, such as a formation integrity test, used to verify cement integrity.
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	An operator 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 operator 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 means a petroleum well that is drilled to explore for or produce petroleum in association with coal or oil shale; or in strata associated with coal or oil shale mining. A CSG well includes the casing for the well and any wellhead for the well attached to it. It does not include shot holes.
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.
ECP	External casing packer

Term	Definition
Evaluation	Includes mud logging, wireline logging and formation evaluation while drilling, coring and well testing.
Exploration well	A well-constructed to explore for petroleum. In this Code, the definition of exploration wells also applies to appraisal wells and gas monitoring wells.
FIT	Formation integrity test. A test of the strength of a formation that is conducted after drilling out a casing shoe track. In a FIT the leak-off pressure is not reached.
Flowing well	Also known as an artesian well. A well from which groundwater is discharged at the ground surface without the aid of pumping.
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 sulphides 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	A definition for horizontal wells is provided in the Petroleum and Gas (Safety) Regulation 2018. Within industry a horizontal well generally refers to a high-angle well with an inclination of greater than 85 degrees from vertical. However constructing a high angle well at a lower inclination – such as 84 degrees – is not a means by which an operator can avoid submitting an exemption to use steel casing in a horizontal well. If operators are unsure of whether they must apply for an exemption they must consult with the PGI. 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.
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, ≥69MPa (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’.

Term	Definition
Intermediate casing	The string of casing sometimes set in a well after the surface casing but prior to the production casing.
kg	Kilograms
Kick	An unplanned entry of water, gas, oil or other formation fluid into the wellbore during drilling.
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 propagated into the formation by the fluid pressure.
Leak-off test (LOT)	Progressive wellbore formation pressure test until leak-off to provide well integrity information.
Legacy borehole	A borehole or well drilled for the purposes of coal, mineral or petroleum exploration or production but not by the current petroleum or mining tenement holder or its related bodies corporate, and where the land has since been relinquished or there is no continuity of tenure to the current tenure.
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.
MCRWBA	Minimum Construction Requirements for Water Bores in Australia
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
MSWBIAB	Minimum Standards for the Construction and Reconditioning of Water Bores that Intersect the Sediments of Artesian Basins in Queensland
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 (oil based muds), mineral oil, or synthetic fluid (synthetic based muds) based invert emulsions.

Term	Definition
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.
Open hole	The uncased portion of a well.
Operations	Any work conducted including rig moves, drilling, running and cementing casing, evaluation, completion, workover and abandonment.
Operator	Refer to the definition in the P&G Act
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
P&G Safety Regulation	Petroleum and Gas (Safety) Regulation 2018
P&G General Provisions Regulation	Petroleum and Gas (General Provisions) Regulation 2017
PCE - Pressure control equipment	Equipment exposed to wellbore fluids whose failure to function as intended can result in an unintended release of wellbore fluid to the environment. During drilling operations well pressure control equipment typically 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.
Perforating	The method of opening a well through the casing to the formation bearing the fluid to be produced.
Permeable hydrocarbon bearing zone	A petroleum reservoir that has sufficient permeability regardless of the required completion design (e.g. hydraulic stimulation) to produce petroleum.
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.

Term	Definition
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.
Suspended well	A shut in well which has additional requirements as defined by an operator's well integrity management system as it has been offline for a significant period of time. While the shut-in timeframe is dependent upon the operators well integrity management system it is expected to be in the order of 2 to 5 years.
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
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 *water monitoring bore* 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).
MCRWBA	Minimum Construction Requirements for Water Bores in Australia.
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

Term	Definition
	• Planning and design • Drilling • Evaluation • Stimulation • Completion • Intervention and workover • Suspension • Abandonment
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 (DNRME, 2018)
- Code of Practice for leak management, detection and reporting for petroleum operating plant (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 Recommended Practice 10B-4, Recommended Practice on Preparation and Testing of Foamed Cement Slurries at Atmospheric Pressure
- API Specification 10A/ISO 10426-1 Specification for Cements and Materials for Well Cementing
- API Specification 12J, Specification for Oil and Gas Separators
- 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 Specification 8A/8C, Grinding of wells (to suit casing elevators)
- API Standard 53, Blowout Prevention Equipment Systems for Drilling Operations.
- API Standard 65-2, Isolating Potential Flow Zones During Well Construction
- 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 13354, Drilling and production equipment - Shallow gas diverter equipment
- 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
- NACE Standard MR 0175/ ISO 15156 Materials for use in H_2S-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)]
- NOHSC: 1013 1995, National Standard for Limiting Exposure to Ionising Radiation

- NOHSC: 3017 1994, Guidance Note for the Assessment of Health Risks Arising from Hazardous Substances in the Workplace
- NOHSC: 3022 1995, Recommendations for Limiting Exposure to Ionising Radiation
- 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
- Queensland Environmental Protection (Air) Policy 2008

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

- An Industry Recommended Practice (IRP) for Canadian Oil and Gas Industry – Volume 5, November 2011.
- 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 H_2S.
- 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 59, Recommended Practice for Well Control Operations
- 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
- Australian Radiation Protection and Nuclear Safety Agency (ARPANSA) - Disposal of Naturally Occurring Radioactive Material (NORM)
- 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
- Oil and Gas UK OP071, 2015, Guidelines for the suspension and abandonment of wells
- 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.

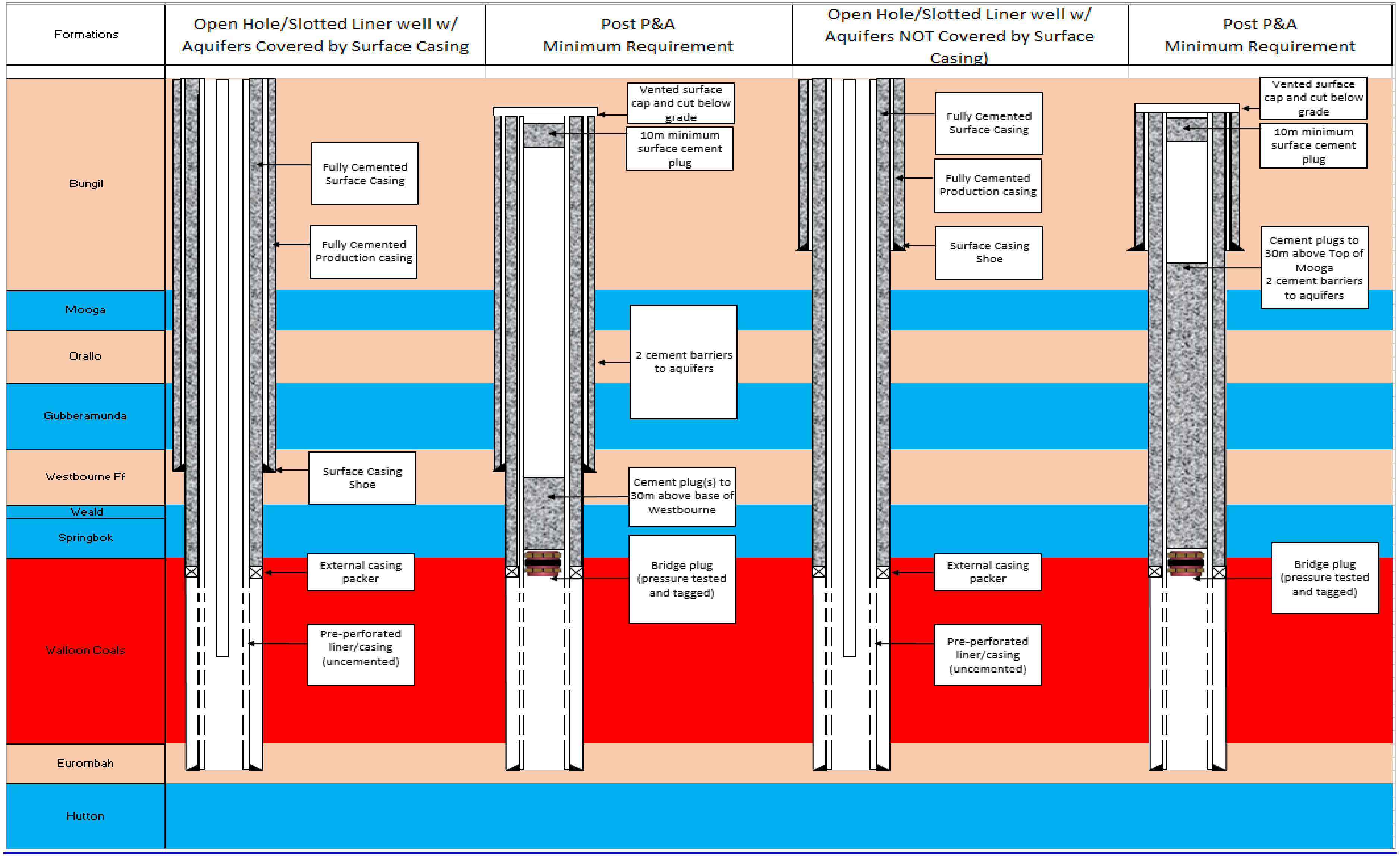
Appendix 3 – Cooper / Eromanga Basin Aquifers

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