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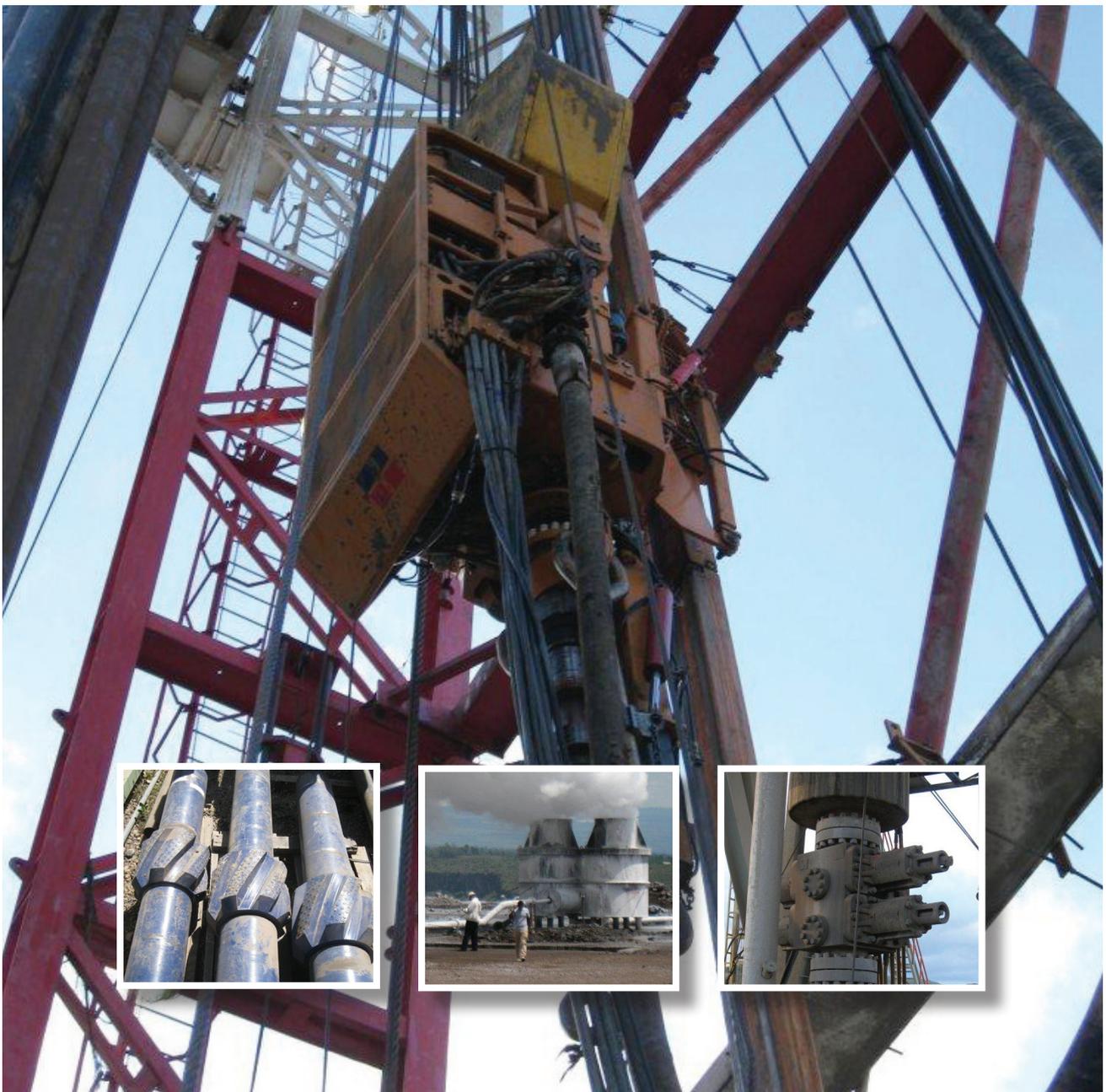
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The African Union Code of Practice for Geothermal Drilling



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The African Union Code of Practice for Geothermal Drilling

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- Comoros
- Democratic Republic of the Congo
- Djibouti
- Eritrea
- Ethiopia
- Kenya
- Rwanda
- Tanzania
- Uganda
- Zambia



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The African Union Code of Practice for Geothermal Drilling has been prepared for the African Union Commission (AUC). The AUC wishes to acknowledge the support received from the German Federal Institute for Geosciences and Natural Resources (BGR). The AUC also wishes to acknowledge the Government of New Zealand for making the *New Zealand Code of Practice* available for inclusion into this document, and R. Gordon Bloomquist, Ph.D., for adjusting and amending this standard to better address the conditions of the geothermal industry in Africa.

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African Union Commission



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Large Photograph: Geothermal Drilling Rig, Olkaria, Kenya. **Small Photographs,** Left to right: Drilling Tools, Aluto, Ethiopia; Well Testing, Menengai, Kenya; Blowout Preventer, Olkaria, Kenya. All Photographs by R. Gordon Bloomquist.

Cover design and layout by Gerry Rasmussen, graphic designer, Gerry Rasmussen Design, Lacey, Washington, USA, working in conjunction with R. Gordon Bloomquist.



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INTRODUCTION

The African Code of Practice for Geothermal Drilling

The pace of geothermal development along the entire East African Rift System is increasing at an ever accelerating rate. A number of factors are contributing to that development including a rapid increase in the need for power as more and more areas in all of the Eastern African countries are being electrified. Estimates, from a number of countries, anticipate that the need for power will exceed a tenfold increase in demand over the next two to three decades. This coupled with the impacts of global climate change on the availability of the hydro systems that now serve many counties makes base load geothermal power a very attractive target for development of the estimated 20,000+ MWe of geothermal potential. Also contributing to the accelerated interest in geothermal power projects are the recent successful increases in geothermal power production from the Kenyan Olkaria field, the formation of the Geothermal Development Company in Kenya, the United Nations Environmental Program (UNEP) and African Rift Geothermal (ARGeo) Program that supports detailed resource assessments and the Geothermal Risk Mitigation Facility (GRMF) of the African Union (AUC) that provides grants for surface studies and reservoir confirmation drilling. Eastern Africa is currently the world's fastest growing geothermal market and on the forefront of many private sector developers.

However, along with the new interest and potential for significant growth in Eastern Africa geothermal development, also come significant risks to the environment, as well as social, health, and safety issues. And although some of the most serious social and environmental impacts may well be experienced only after lengthy periods of exploration, well field development drilling and power plant construction and operation, the most immediate risks are those associated with deep exploration or reservoir confirmation drilling. Drilling risk is real and must be taken extremely seriously due to the potential risk to health, life and the environment.

Risks include the potential for blowouts of the well that may, in addition to resulting in potentially serious impacts upon the environment, result in serious injury or death of personnel involved in drilling operations. Other health risks are associated with the escape of toxic gases such as H₂S which may impact not only the drilling crews and associated personnel, but may also present a serious health risk to persons living in the vicinity of drilling operations and/or to their domestic livestock. There is also a significant risk that drilling operations may have a significant negative impact upon potable water supplies from either surface spillage or from the contamination of potable ground water sources from either the intrusion of drilling fluids into potable groundwater horizons or through the creation of pathways that allow for the mixing of what may be non-potable geothermal fluids with potable reservoirs.

In order to address the needs of the geothermal industry relative to the drilling of deep geothermal wells and to assist the countries of Eastern Africa meet the challenge of regulating geothermal drilling activities, the African Union Commission (AUC) and the German Federal Institute for Geosciences and Natural Resources (BGR) in partnership organized and convened a workshop “*Rules and Regulations for Drilling and Completing Geothermal Wells*”. The workshop was held in Naivasha, Kenya in May of 2014 and was designed to evaluate the need for the development of a comprehensive Code of Practice for Geothermal Drilling and how such a Code could best be developed to serve the needs of the African Union Commission GRMF program and African geothermal development in general. The workshop was attended by representatives of several Eastern African countries where the initiation of geothermal drilling was most likely to occur based on receipt of GRMF grants. The three-day workshop introduced the attendees to the risks associated with deep geothermal drilling as well as how different jurisdictions (United States and New Zealand) have successfully dealt with that risk through the development and adoption of Codes of Practice or Rules and Regulations. The attendees also heard from those responsible for enforcement of any such regulations as well as those that would be subject to and responsible for ensuring that all operations undertaken under such regulation are complied with in a responsible manner.

It was clear from the discussions held during the workshop and from a review of the questionnaire that was completed by each of the attendees following the workshop that the establishment of a sound comprehensive Code of Practice *should* be given highest priority and that additional workshops to directly address the development of a Code *should* be organized and convened. It was also the consensus of those in attendance that the *New Zealand Code of Practice*, that was being revised and would thus become the most comprehensive and up to date Code available internationally, *should* be further examined as the basis for a Code of Practice for the drilling of geothermal wells in Africa.

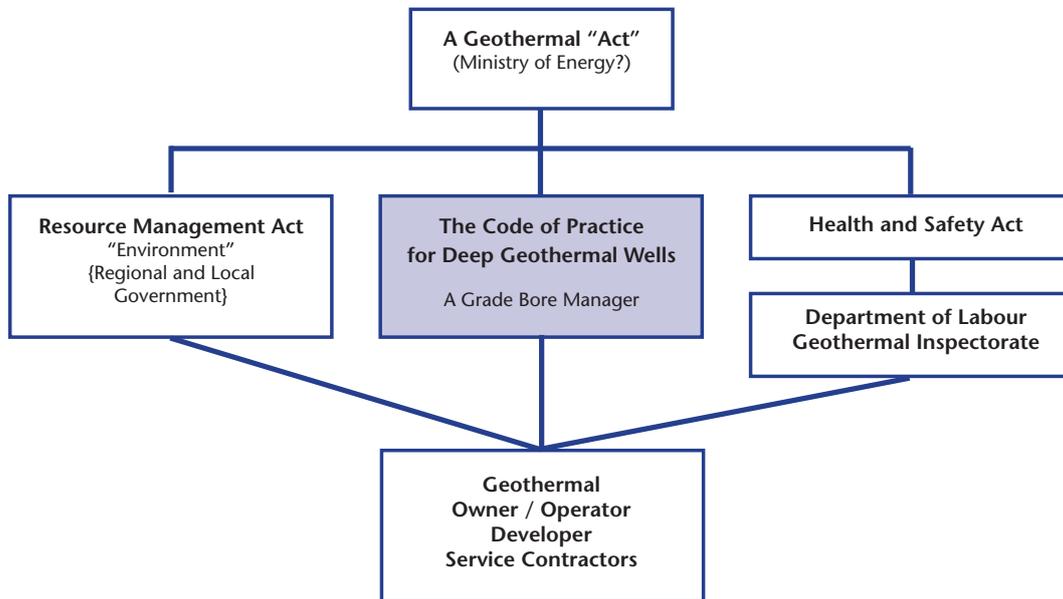
Based upon the outcome of the Naivasha workshop and further discussions among the organizers, a second workshop was organized and held in Entebbe, Uganda February 10-12, 2015. The workshop focused on the newly revised New Zealand Code of Practice and its applicability to meeting the needs of geothermal drilling in Africa in terms of providing not only safeguards for the environment and protection for the health and safety of those engaged in drilling activities or living in near proximity to such activities, but also the role of the Code in ensuring sound drilling practices and capture of vital geological data during drilling, logging and testing of geothermal wells.

The three day workshop was attended by representatives of seven Eastern African countries (Comoros, Djibouti, Eritrea, Ethiopia, Rwanda, Tanzania and Uganda) as well as representatives of the African Union Commission, Economic Community of the Great Lakes Countries, German Federal Institute for Geosciences and Natural Resources, German Development Bank and United Nations Environment Programme.

After a thorough introduction to the *New Zealand Code* and what the Code does and does not address relative to filling the needs of African countries it became very evident that the *New Zealand Code* is not a stand-alone document, but rather one major element of a comprehensive legal and regulatory framework that on the one side consists of statutes and

promulgated rules and regulations that address natural resource, land, water and environmental issues while on the other side statues that cover occupational health and safety issues.

Figura A
The New Zealand Legal and Regulatory Framework



As can be clearly seen in the above diagram, in New Zealand, the Code of Practice is but a part of a comprehensive legal and institutional framework that regulates geothermal drilling activities. In Africa the tie between *The African Union Code of Practice for Geothermal Drilling* and National statutes is less well defined and in some cases there remains a need to more fully develop National environmental, land use and occupational health and safety statutes as they relate to not only geothermal drilling, but to all aspects of geothermal development and operation. It is therefore advised that all developers, public as well as private, abide by not only *The African Union Code of Practice for Geothermal Drilling* but also make every attempt possible to follow the mandates of National statutes and implementing rules and regulations that are intended to enforce land use statutes, environmental and social safeguards and occupational health and safety guidelines. **DEVELOPERS SHOULD AT A MINIMUM ABIDE BY THE WORLD BANK PERFORMANCE STANDARDS ON ENVIRONMENTAL AND SOCIAL SUSTAINABILITY.**

To be best understood, it is paramount that the situation in Eastern Africa must be given full consideration in light of the fact that the *New Zealand Code* when applied to the situation in Africa requires that the user gain a full understanding of the associated laws of the country in which geothermal drilling is to take place. The Code is a guidance document that provides a number of suggestions relative to best practices in geothermal drilling-some which *should* be given serious consideration and other that **shall** be complied with. However, simply complying with the provisions of the Code may not fulfill national or even local requirements that are in place relative to for example environmental safeguards or occupational health and safety requirements.

As such, recipients of GRMF grants must not only conduct drilling activities as provided for by the Code but ensure that they are also conducting those activities in compliance with the laws and rules and regulations of the country in which the drilling is taking place. Nothing in the Code is meant to exempt any entity from compliance with those national or local requirements. And in no instance **shall** the provisions of the Code be taken to supersede national or local statutes.

If adoption of the Code is to be considered by individual national or local governmental entities it is also important that they understand that there are a number of important aspects of geothermal drilling regulation that are not addressed in the Code as it now stands. For example the Code does not address the following critical issues:

- Designation of responsible authority (ministry, agency or department)
- The application process and requirements thereof
- Application fees
- Bonding requirements
- Enforcement of the provisions of the Code
- Penalties for noncompliance with the provisions of the Code

Such provisions can be incorporated into the Code itself or they could be incorporated into statutes that are designed to provide access to land, water or natural resources or provide protection for the environment.

Purpose

It is hereby found and determined by the African Union Commission that the people of Eastern Africa have a direct and primary interest in the development of geothermal resources and that wells for the discovery and production of geothermal resources **shall** be drilled, operated, maintained and abandoned in such manner as to safeguard life, health, property and the public welfare, and to encourage maximum responsible economic recovery.

Acknowledgement

The African Code of Practice for Geothermal Drilling has been prepared for the African Union Commission (AUC) and the German Federal Institute for Geosciences and Natural Resources (BGR). The AUC and BGR wish to acknowledge the Government of New Zealand and Standards New Zealand for making the *New Zealand Code* available for inclusion into this document.

Disclaimer

The African Union Commission, the German Federal Institute for Geosciences and Natural Resources, the New Zealand Government and Standards New Zealand as well as contributors to and editors of this publication do not guarantee the accuracy of the data and information included in this publication and accept no responsibility whatsoever for any consequence of the use of any data or information contained herein.



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APPENDIX A – Consolidation grouting (Informative)

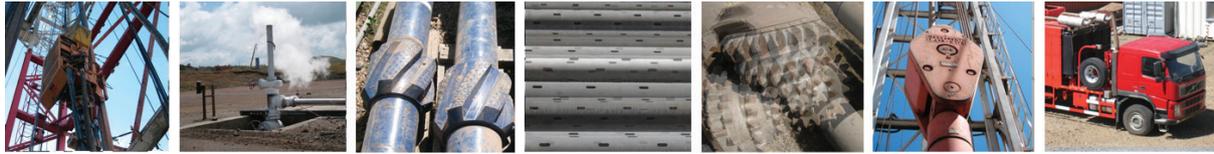
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REFERENCED DOCUMENTS

The following publications are either directly referenced in this code or else contain information that is relevant to its development and implementation.

AMERICAN STANDARDS

American Petroleum Institute

API Spec 4F:2013	Specification for drilling and well servicing structures
API RP 5A3:2011	Recommended practice on thread compounds for casing, tubing, line pipe and drill stem elements
API RP 5C1:1999	Recommended practice for care and use of casing and tubing
API TR 5C3:2008	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
API Spec 5CT:2011	Specification for casing and tubing
API Spec 5DP:2009	Specification for drill pipe
API Spec 5L:2012	Specification for line pipe
API Spec 6A:2013	Specification for wellhead and Christmas tree equipment
API Spec 6D:2012	Specification for pipeline valves
API Spec 7-1:2012	Specification for rotary drill stem elements
API Spec 7-2:2010	Specification for threading and gauging of rotary shouldered thread connections
API Spec 7F:2010	Specification for oil field chain and sprockets
API RP 7G:2009	Recommended practice for drill stem design and operation limits
API Spec 7K:2010	Specification for drilling and well servicing equipment
API Spec 8A:2001	Specification for drilling and production hoisting equipment
API RP 8B:2012	Recommended practice for inspections, maintenance, repair, and remanufacture of hoisting equipment
API Spec 8C:2014	Specification for drilling and production hoisting equipment
API Spec 9A:2012	Specification for wire rope
API RP 9B:2012	Recommended practice for application, care, and use of wire rope for oil field service
API Spec 13A:2010	Specification for drilling fluid materials
API RP 13B-1:2009	Recommended practice for field testing water-based drilling fluids
API RP 13I:2009	Recommended practice for laboratory testing of drilling fluids
API Spec 15HR:2001	Specification for high pressure fibreglass line pipe
API Spec 16A:2004	Specification for drill through equipment
API Spec 16RCD:2005	Drill through equipment-rotating control devices
API RP 64:2001	Diverter systems equipment and operations

API STD 53:2012 Standard for blowout prevention equipment systems for drilling wells

American National Standards Institute

ANSI/ASME B16.5:2013 Pipe flanges and flange fittings
ANSI/NACE MR 0175/ISO 15156:2009 Petroleum and natural gas industries – Materials for use in H₂S-containing environments in oil and gas production

American Society of Mechanical Engineers

ASME :2010 Boiler and pressure vessel Code, Section VIII, Pressure vessels

American Society for Testing and Materials

ASTM E1008-03:2009 Standard practice for installation, inspection, and maintenance of valve body pressure relief methods for geothermal and other high-temperature liquid applications

OTHER PUBLICATIONS

- Eaton, B.A. Fracture Gradient Prediction and its application in oilfield operations, Journal of Petroleum Technology, 1969, V246, p1353-1360
- Enform, Canada, Petroleum Industry Training Service: Heavy Oil and Oil Sands Operations, Industry Recommended Practice (IRP) Volume 03-2002
- Enform, Canada, In situ Heavy Oil Operations (IRP3 2012 3.2.1.3.1e)
- Holliday, G. H., Calculation of Allowable Maximum Casing Temperature to Prevent Tension Failures in Thermal Wells. ASME (Series) 69-PET-10, 1969
- Parry, W.T. et al, ASME International Steam Tables for Industrial Use. Second Edition, 2009
- WorkSafe New Zealand, Health and safety guidelines for shallow geothermal wells, 2005 (previously the NZ Department of Labour)

Related documents

ANSI/ASME B31.1:2012 Power piping
API Spec 10A:2010 Specification of cements and materials for well cementing
API RP 10B-2:2013 Recommended practice for testing well cements
API RP 49:2001 Recommended practice for safe drilling of wells containing hydrogen sulphide
ISO/PAS 12835:2013 Qualification of casing connections for thermal wells
ISO 13679:2002 Petroleum and natural gas industries -- Procedures for testing casing and tubing connections

LATEST REVISIONS

The users of this code should ensure that their copies of referenced documents listed on pages xii and xiii are the latest revisions.

Standards referenced in this code will continue to evolve beyond the publication of this code. Take care to ensure that standards more recently published remain contextually appropriate; if there is any doubt, use the version of the standard referenced in this code.

For updates to this code, go to *www.grmf-eastafrika.org*.

Review of standards

Suggestions for improvement of this code are welcome. They should be sent to the following:

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Regional Geothermal Coordination Unit**
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Website: *www.africa-union.org*

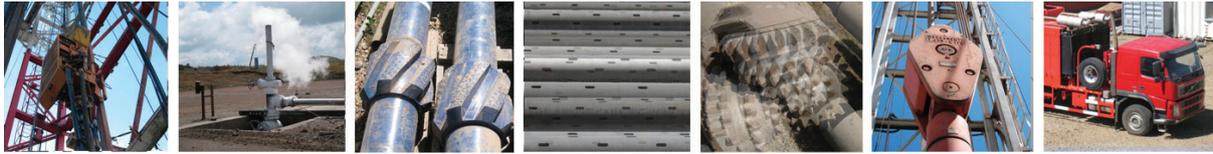
**Chief Executive
Standards New Zealand**
Private Bag 2439
Wellington 6140 New Zealand

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Fax: (04) 498 5994

Website: *www.standards.co.nz*

Hydraulic Fracturing

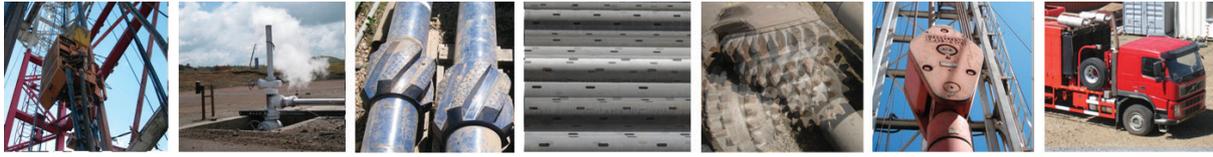
The practice of hydraulic fracturing (also known as “fracturing”), widespread in the oil and gas industry, is not a recognised practice generally employed in the geothermal industry. Consequently, this code does not address such practices.



POLICY

Outcome statement

This code promotes best practice in the management of deep geothermal wells throughout their lifetime from drilling through to abandonment of wells. It provides guidance and encourages operators, drilling contractors, service companies, regulators, and other stakeholders to improve the overall management of wells, including safety and environmental management. The Code also helps ensure that all relevant technical and scientific data that can and should be obtained during all drilling operations is collected and made available to the appropriate governmental entity of the country in which the drilling takes place. Such data will greatly add to the geological data base and understanding of the geothermal development potential.



1 GENERAL

1.1 Scope

1.1.1 – Application of the code

The good practices specified in this code may be applied to a range of circumstances. But it is applicable specifically to geothermal wells that:

- (a) Reach, or may reasonably be expected to reach, a depth exceeding 250 m and contain predominantly water or steam at temperature exceeding the boiling point of water for the mean ambient conditions at the surface of the well site; or
- (b) Reach, or may reasonably be expected to reach, a depth of between 150 m and 250 m, and that;
 - (i) Contain steam or hot water that may reasonably be expected to exert a shut-in pressure at the wellhead of 0.5 MPa or greater; or
 - (ii) Have expected or actual downhole temperatures within 20°C of the boiling point for depth (BPD) temperature as measured from the local water level.

1.1.2 – Inclusions

The code covers the drilling, operation, repair, and abandonment of deep geothermal wells. It includes all subsurface work plus the wellhead up to the top of the master valve.

The code also applies to continuous wireline coring, coiled tubing operations, or other non-typical methods for constructing and maintaining deep geothermal wells.

NOTE:

- (a) Extreme or unusual conditions may create circumstances that are beyond the scope of this code. These may be conditions such as temperatures above the Critical Point (373°C) of water or the presence of highly corrosive fluids.
- (b) The boiling temperature of water reduces with increasing elevation, which should be taken into account. Dissolved solids and non-condensable gas also affect the boiling temperature of water. In the absence of better data, mean values can be interpolated from Table 1.

- (c) The Health and Safety Guidelines for Shallow Geothermal Wells, New Zealand Department of Labour 2005, covers requirements for shallow geothermal wells (less than 150 m or between 150 m – 250 m with conditions that do not exceed the conditions stated in 1.1 (b)).

Table 1
Variation of ambient pressure and boiling temperature for pure water with elevation

Elevation (m)	Ambient Pressure (kPa)	Boiling Temperature (°C)
Sea level	101.3	100
+ 500	95.5	98
+ 1000	89.9	97
+ 2000	79.5	93
+ 3000	70.1	90
+ 4000	61.5	86

1.1.3 – Exclusions

This code does not cover:

- (a) Reservoir engineering, although changes in reservoir conditions (for example, because of exploitation) may need to be considered in the design of wells;
- (b) Environmental management of drilling and well operation activities including control of surface run-off, disposal of drilling fluids, and noise. These will usually be covered by environmental consents and permits of the country under which the work is undertaken;
- (c) Occupational health and safety requirements generally covered by national legal statues and implementing rules and regulation.
- (d) Equipment or operations downstream of the master valve or other components of the wellhead containing the geothermal fluids (as defined in 2.11.1, see page 41), except where they may affect the design or use of well components; or
- (e) The design, construction, and maintenance of any thrust frame.

1.2 Variation from mandatory provisions

Any variation from a mandatory provision of this code **shall** be based on sound data and engineering, or the use of alternative recognised standards. Any variations **shall** be adequately justified and documented. The documentation **shall** be permanently stored by the well owner and be available to regulatory authorities (see 5.13 on page 106 and 6.3 on page 109).

The code does not preclude the adoption of alternative techniques based on either sound data and engineering, or the use of alternative recognised standards if approved by a third party peer review.

1.3 Definitions

1.3.1 – Focus on geothermal industry best practice

The definitions in this code generally conform to international usage. In particular, the various casing strings are defined as shown in Figure 2 on page 18.

1.3.2 – Defined terms

For the purpose of this code, the following definitions apply:

Aerated drilling fluid	A mixture consisting principally of compressed air, and either mud or water
Abandon	Seal a well in order to render it permanently inoperative without provision for future reinstatement (also ‘abandonment’)
Anchor casing	The cemented casing on which the permanent wellhead is mounted. In some cases, this may be the same as the production casing
Annulus	The space between two concentric objects where fluid can flow, such as between the wellbore and drill pipe or between two casings
Banjo Box	Diverter tee in drilling wellhead used while drilling with aerated fluids
Bleed	To discharge a well at a very low rate in order to maintain the wellhead and casing in a hot condition
Blooie line	Flow line from Banjo Box to air-water separator used while drilling with aerated fluids

Blowout	An uncontrolled flow of reservoir fluids, whether into the wellbore while drilling, or out of the wellbore into the formation above the reservoir, or to the surface. A blowout may consist of steam, water, gas, or a mixture of these. Blowouts can occur in all types of exploration and production operations, not just during drilling operations. If reservoir fluids flow via the wellbore into another formation outside of the reservoir and do not flow to the surface, the result is called an underground blowout. In geothermal wells interzonal flows commonly occur within the reservoir and these are not considered to be a blowout
Blowout Preventer	A blowout preventer (BOP) is a large, specialized valve or similar mechanical device, used to seal, control, and prevent the uncontrolled release of fluids from a well during drilling operations.
Boiling-point-for-depth	Conditions representing a column of pure water at boiling (saturation) temperature corresponding to the pressure at every depth
Bore	See <i>Well</i>
Broaching	A wireline operation using gauge cutting devices to remove scale from inside a well
Casing	Casing joints or casing string
Casing connection	The threaded interfaces between casing joints that connect single joints of casing together. In some cases, the connection may be integral with the casing joint, with or without an external or internal upset
Casing coupling	A short length of pipe used to connect two joints of casing. A casing coupling has internal female threads machined to match the external male threads of the long joints of casing. The two joints of casing are threaded into opposite ends of the casing coupling.
Casing head flange	The flange attached to the anchor casing, to which the permanent wellhead is attached
Casing joint	A length of steel pipe, generally between 6 –13 m long with a casing connection at each end. Casing joints are assembled to form a casing string
Cellar	An excavation, usually concrete-lined, around the top of the well to accommodate part of the wellhead and assist in managing drilling mud or water around the wellhead during drilling and throughout the life of the well
Choke line	A high-pressure pipe leading from an outlet on the lower blowout preventer (BOP) stack to a throttling valve and associated piping. This is used to control flow and pressure from the well

Compressive strength	Ultimate stress at which a material fails in compression
Conductor pipe	The large diameter, very shallow pipe, normally installed before drilling commences. The conductor pipe is used to retain surface material against collapse or washout, and to elevate returning drilling fluid to above ground level. BOP equipment is not usually installed on the conductor pipe because of its shallow depth. Also referred to as a 'precollar'.
Casing connection strength	Force at which a casing connection is predicted to fail
Design factor	The dimensionless ratio: Where the material strength is the specified minimum value corrected for any temperature or corrosion effects, and the force or stress is the total value, including any biaxial effect
Drilling programme	A formal document that sets out the steps and processes required to construct the well safely and in compliance with the well design
Effective Containment Pressure	Pressure that a formation at any depth can contain so that fluid will not migrate to the surface or other shallow aquifers either directly or through faults or nearby wells
Formation fracture pressure	The pressure required to induce fractures in rock at a given depth. This is typically established using a formation leak-off test (FLOT)
Formation leak-off test	A test to determine the strength or formation fracture pressure of the rock formation, usually conducted immediately after drilling below a new casing shoe. During the test, the well is shut in and fluid is pumped into the wellbore to gradually increase the pressure that the formation experiences until that pressure increase ceases, indicating formation fracture pressure has been reached
Geothermal	Associated with heat derived from the earth
Go-devil	Cylindrical tool used to check the drift diameter of casing or liner
Intermediate casing	Casing installed where required by subsurface conditions to enable target depth to be reached for that stage of the well
Internal yield pressure	Pressure at which the internal wall of the casing reaches yield stress
Interzonal flow	Flow between two permeable zones through the wellbore. Where the permeable zones are within the reservoir this is not considered to be a blowout
Joint	A single length of pipe or casing

Kill line	A high-pressure line leading from the rig pumps to an inlet at the bottom of the BOP stack to allow fluid to be pumped into the well
Liner	Casing joints connected together in a string that does not extend back to surface
Liner lap	The annular space in the overlap between the top of a liner and the bottom of the previous (outer) casing string. This may be either cemented or uncemented
Master valve	The primary containment valve on the well located above the CHF
Maximum Design Pressure	For any considered well section, this is the assessed maximum pressure that can be generated within the well section, both during construction and service
Measured depth	A measurement of pipe, casing or hole section length as measured along the wellpath from the surface datum to the point of interest
Neutral temperature	The temperature of the casing at the depth and time that the cement sets in the annulus
Perforated liner	An uncemented string of perforated liner installed across the open hole to protect the wellbore from collapse due to unstable rock formations, pressure drawdown or erosive effects of fluid flow
Pipe body strength	Axial force at which the pipe body reaches yield
Pipe collapse pressure	External pressure at failure due to yield or collapse
Primary pumps	Rig pumps used to circulate fluids through the drill string and into the well
Production casing	The deepest cemented casing string extending to the surface. If the wellhead is attached to this casing string it is also the anchor casing
Production casing shoe	The shoe of the production casing or production liner that defines the transition between cased hole and open hole in the completed well
Production liner	A cemented liner installed as the first stage of a tie-back completion. The production liner will usually be the deepest cemented casing
Quench	To inject cold liquid into the well to condense or prevent the formation of steam, or to reduce temperatures for other purposes so that there is no positive pressure at the wellhead
Scab liner	A cemented or partially cemented casing string installed inside the production casing or anchor casing. This is usually installed during a workover to repair damaged casing

Shoe	The bottom of a casing or liner string
Side valve	A small valve attached to the wellhead below the master valve. Sometimes called the wing valve
Site	Area prepared to accommodate the rig and all ancillary equipment during a drilling operation or workover
Standpipe	High-pressure pipe connecting primary pumps to the kelly hose. The Standpipe pressure thus indicates the delivery pressure at the top of the drill string
String	A set of joints of pipe or casing, connected together and considered as a single unit
Sump	Excavation designed to collect drilling cuttings and waste products generated during the drilling operation
Suspend	In relation to a well, is to render well temporarily inactive, and ‘suspension’ has a corresponding meaning
Surface casing	The first casing installed in the well that supports a drilling wellhead
Tensile strength	Ultimate stress at which a material fails in tension
Thermal stress constant	The incremental stress induced in casing held against movement per unit rise in temperature
Thread dope	Thread lubricant or sealing compound applied to drill pipe and casing connectors
Thrust frame	A frame, usually installed on permanent wellheads and anchored into the surrounding cellar or into the ground, to support the wellhead from lateral forces
Tie-back casing	A casing string that is connected to the top of a production liner and is cemented back to the surface
Vertical depth	The depth of any point measured vertically from the surface datum down to the point of interest
Well	A borehole drilled for the appraisal or use of geothermal fluids. It includes any borehole for production, injection, reinjection, or reservoir monitoring purposes
Wellbore	The drilled hole or borehole including the open hole or uncased portion of the well
Wellhead	A set of valves and other pressure-rated components joined to the top of the well and used to contain the well fluids
Well section	A combination of cased and open hole section that exists either as part of well construction or the final completed well
Workover	Any operation during which a well is re-entered for the purpose of maintenance or repair

1.4 Units of measurement

Because most of the rotary drilling standards were developed in the United States of America, there is still widespread use of the U.S. customary units of measurement (for example, feet and psi), together with others adopted in the petroleum industry (for example, barrels).

In this code, International System of Units (SI) units of measurement and abbreviations are used. However, it remains common practice to use imperial units for some diametrical and flow measurements.

For well coordinates, elevations, and directional information the measurement units being applied in all records **should** be recorded; that is, the coordinate system, datum for elevations, and azimuth units (magnetic or grid).

Where pressure is used without qualification, it **shall** be taken to mean pressure above ambient.

1.5 Notation

This code uses the following notations:

a	coefficient of thermal expansion ($^{\circ}\text{C}^{-1}$)
A_p	cross-sectional area of casing wall (mm^2), allowing for any slotting
d	casing inside diameter (mm)
D	casing outside diameter (mm)
e	eccentricity (mm) = actual (not nominal) hole diameter minus D
E	modulus of elasticity (MPa)
f_b	maximum stress due to bending (MPa)
f_c	total extreme fibre compressive stress due to axial and bending forces (MPa)
f_t	maximum tensile stress (MPa)
$F_{buoyancy}$	buoyancy force (kN)
$F_{csg\ air\ wt}$	air weight of casing (kN)
$F_{csg\ contents}$	weight of internal contents of casing (kN)
$F_{hookload}$	surface force suspending casing that is subject to gravitational and static hydraulic loads (kN)
$F_{displaced\ fluids}$	weight of fluids displaced by casing (kN)
F_c	change in axial force within casing body due to heating (kN)

F_m	net downward force applied by the wellhead (kN), due to its own mass and any pipework reactions (kN)
F_p	Axial force within casing body at cement set (kN)
F_r	resultant axial force within casing body, combining the force at cement set and subsequent thermal forces (kN)
F_t	change in axial force within casing body due to cooling (kN)
F_w	lifting force due to wellhead pressure (kN)
g	acceleration due to gravity (for example 9.81 m/s ²)
I_p	net moment of inertia of the pipe section, allowing for any perforations (mm ⁴)
L_{if}	vertical length of a section of fluid having the same density – within the casing (m)
L_{ef}	vertical length of a section of fluid having the same density – within the external annulus (m)
L_f	total vertical length of a fluid column in an annulus (m)
L_z	total vertical length of liner or casing (m)
P_f	pore pressure (MPa)
ΔP	differential pressure on casing during cementing (MPa)
P_{frac}	in situ fracture pressure of a formation (MPa)
P_w	maximum wellhead pressure (MPa)
P_z	external fluid pressure at casing shoe (MPa)
R_i	temperature reduction factor (ratio)
R_j	connection efficiency in compression
S_v	overburden pressure (vertical pressure due to the weight of the overlying formations MPa)
T_1	neutral temperature (temperature of casing at time of cement set (°C))
T_2	maximum expected temperature (°C)
T_3	minimum temperature after cooling well (°C)
W_p	nominal unit weight of casing in air (kg/m)
q	curvature (degrees per 30 m)
ν	Poisson's ratio
π	3.142 (that is to 4 significant figures)
ρ_{ef}	density of a section of fluids with constant density within an annulus (kg/l)
ρ_{if}	density of a section of fluids with constant density within a casing (kg/l)
ρ_c	cement slurry density (kg/l)
ρ_f	density of fluid – usually water – in the wellbore or annulus (kg/l)

1.6 Abbreviations

Abbreviations have the following meanings:

BOP	blowout preventer
BPD	boiling-point-for-depth
CHF	casing head flange
FLOT	formation leak-off test
LCM	lost circulation material
MPa	Megapascal. 1 MPa is equal to 10 Bar
NRV	non-return valve
OEM	original equipment manufacturer
SG	specific gravity
SI	Le System International d'Unites/International System of Units
TVD	true vertical depth
WHP	wellhead pressure

1.7 Interpretation

For the purposes of this code the word '**shall**' refers to practices that are essential for demonstrating best practice as set out in this code.

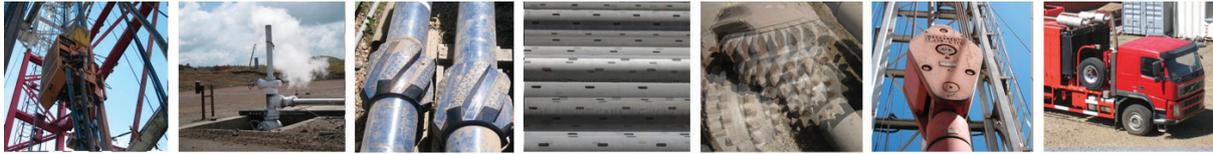
The word '**should**' refers to practices that are strongly advised or recommended.

Notes are used throughout this code to provide additional guidance that is advisory to the main text.

The term '**informative**' is used in this code to define the application of the appendix to which it applies. An informative appendix gives additional information, and is only for guidance. It does not contain requirements.

1.8 Record keeping

The documentation and records required under each section of this code **shall** be permanently maintained and stored by the well owner and copies forwarded to the appropriate government Ministry, Agency, Department or Office responsible for the granting of geothermal drilling licenses or maintaining geological data.



2 WELL DESIGN

2.1 In this section

Section 2 covers the design of wells. Aspects to consider include:

- (a) The subsurface conditions likely to be encountered;
- (b) The required equipment and material performance; and
- (c) Drilling practices to ensure long-term well integrity.

2.1.1 – Design inputs and assumptions

The prediction of deep rock and fluid conditions can be subject to considerable uncertainty, particularly in exploration. Conservative assumptions or design factors **should** therefore be adopted. As the well drilling progresses, sufficient data **should** be collected to confirm the validity of the well design, or to indicate where further observations or design modifications are required.

2.1.2 – Design considerations

The design **should** consider:

- (a) Intended purpose;
- (b) Design lifetime; and
- (c) Ongoing operation and maintenance.

Assumptions such as corrosion rates, erosion rates, and thermal cycles used in determining well life **shall** be recorded as part of design documentation (see 2.1.3).

2.1.3 – Drilling programme to be prepared

Before drilling operations begin, a detailed well design and drilling programme **shall** be prepared. The well design and drilling programme **shall**:

- (a) Describe the works;
- (b) Demonstrate that there are adequate precautions to satisfy the provisions of this code; and
- (c) Include the well control methods used during drilling.

2.1.4 – Design review

Well design **should** be prepared by engineers competent in geothermal well design, and familiar with this code, and **shall** be peer reviewed by an appropriately qualified and experienced person.

2.2 Casing strings

2.2.1 – Casing service

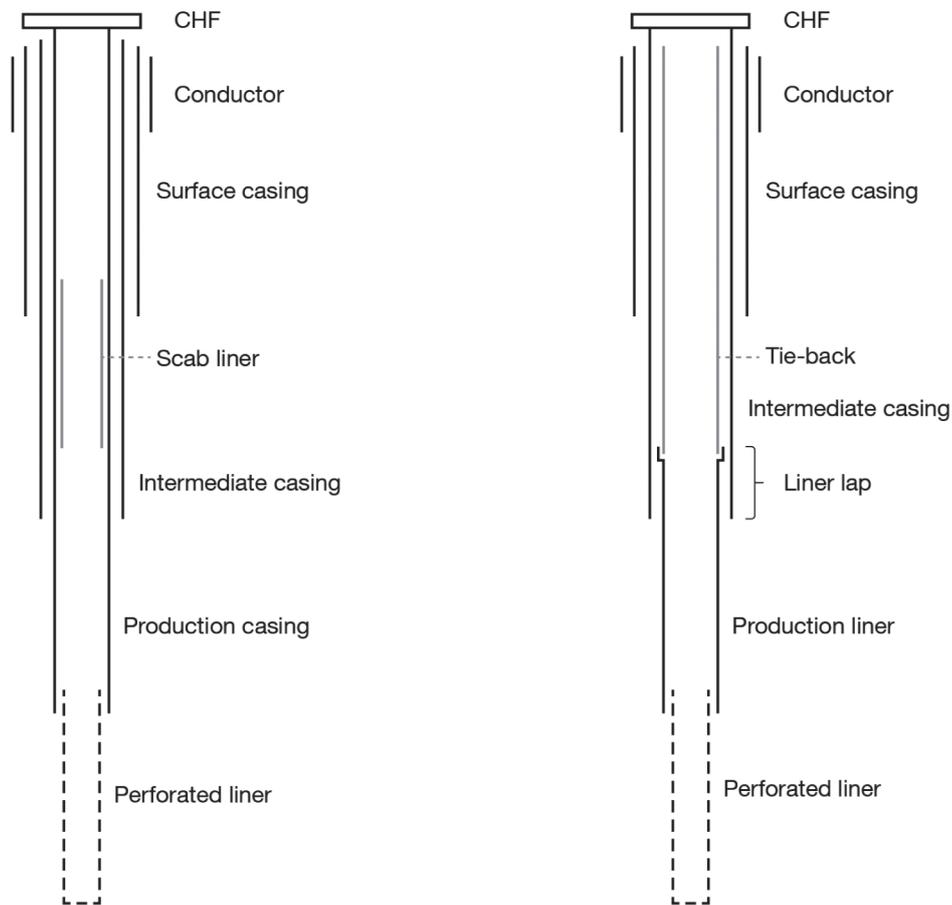
The design of casing strings in geothermal wells **shall** take into account conditions anticipated during drilling as well as those anticipated over the life of the well. Specifically, the casing design criteria **shall** include the following considerations:

- (a) Prevent the collapsing, bursting, buckling, or other deformation of casing;
- (b) Support drilling and permanent wellheads;
- (c) Safely contain well fluids;
- (d) Control contamination of subsurface aquifers;
- (e) Counter circulation losses during drilling; and
- (f) Protect the integrity of the well against corrosion, erosion, or fracturing.

2.2.2 – Casing terminology and description

Figure 1 illustrates the meanings given to different casings throughout this code. See 1.3.2 starting on page 3 for a list of defined terms.

Figure 1
Naming conventions used for casing strings and liners



(a) Completion with production casing used as anchor casing

(b) Completion with an intermediate casing used as anchor casing

2.2.3 – Wellhead attachment

The wellhead may be attached to the innermost casing - the production casing or tieback, or a shallower intermediate casing. In each case, the casing with the wellhead attached also becomes defined as the anchor casing (see Figure 2 on page 18).

NOTE

A scab liner does not form part of a conventional completion. It may be installed later in the well life to repair damaged casing.

Wells with cemented production liners do not always have tie-back casings installed on completion.

2.3 Well design process

The well design process generally consists of the steps outlined in Table 2. The well design process is further detailed in sections 2.4 to 2.13.

Table 2
The well design process, step by step

Step	Action
1	Determine an intended vertical well depth, wellhead location, and well target.
2	Collect all available data and assessments on expected subsurface conditions between the wellhead and the well target. This includes but is not restricted to: <ol style="list-style-type: none"> a. Temperature versus depth b. Pressure versus depth c. Geological formations expected d. Assessment on competency of geological formation and intervals of lost circulation e. Assessment of any anticipated problem zones.
3	Assess the Maximum Design Pressure over the depth of the well.
4	Assess the Effective Containment Pressure of the formations over the depth of the well.
5	Determine safe casing shoe depths for each casing string back to surface. To do this, use: <ol style="list-style-type: none"> (1) Maximum Design Pressure; (2) Effective Containment Pressure; (3) Knowledge of formation integrity; and (4) Knowledge of anticipated problem zones.
6	Determine a desired production casing (or production liner) and open hole diameter. Consider the well's final use and desired production/reinjection performance when making this assessment.
7	Determine desired size, weight, grade and connections of casing strings, and associated hole sizes for each casing string back to the surface.
8	Check each casing string for strength against running and cementing loads. Revise design if necessary.
9	Check each casing string for safe pressure containment of Maximum Design Pressure during well construction. Revise design if necessary.
10	Review each casing string for loadings under anticipated well service conditions, and revise design if necessary.

2.4 Subsurface conditions

2.4.1 – Assessment of subsurface conditions

An assessment **shall** be made of the subsurface conditions anticipated throughout the well path. To do this, use information from nearby wells and from relevant scientific and engineering appraisals. The assessment **should** include expected temperatures, fluid types, fluid compositions, and pressures as well as the relevant geological information:

- (a) Lithology of geological formations including the location of any specific stratigraphic marker beds;
- (b) Intensity and nature of rock alteration;
- (c) Compressive strength, or at least the degree of rock consolidation;
- (d) Faulting, fracturing, and gross permeability;
- (e) Potential for unstable formations, such as unconsolidated breccias or volcano-sedimentary sequences, or lithologies that might contain water-sensitive swelling clays; and
- (f) Fracture pressures obtained from FLOTs on nearby wells or from similar formations.

2.4.2 – When subsurface conditions cannot be inferred from available data

In exploratory wells, sometimes temperature and pressure profiles versus depth cannot be inferred using data from nearby wells or from surface investigations. In this case, information to be used for well design **shall** be determined as follows:

- (a) Unless there is a suspicion of artesian conditions, subsurface fluid pressures **shall** be the hydrostatic values for a column of cold water below the general groundwater level of the area. If the groundwater hydrology, local topography, or natural thermal features suggest artesian conditions, design fluid pressures **shall** be increased to the extent implied by such indications; and
- (b) Subsurface temperature values **shall** be assumed to follow saturation conditions for a column of boiling water below the same level defined by (a).

NOTE

- (1) Saturation pressures corresponding to subsurface temperatures will be less than the old hydrostatic pressures derived in (a).
- (2) Pressure and temperature values are plotted in Figure 2 (see page 18) and can be interpolated from Table 3 (see page 16).

- (3) Analysis of nearby spring and fumarole samples could indicate steam vapour conditions are present at depth. If this is the case, compute or model design fluid pressures to provide for a steam vapour column, the pressure of which should correspond with the indicated source temperature at saturated steam conditions. For the vertical extent of the steam vapour column, consider geological and geophysical indications. Assume that a steam vapour column is in pressure equilibrium with the top of a boiling water column.

2.4.3 – Hydrostatic pressure and BPD

Table 3 shows the standard hydrostatic pressures and BPD temperatures for a column of pure water with no dissolved gas, assuming water level at sea level (pressures are gauge not absolute).

Table 3
Standard hydrostatic pressures and BPD temperatures for a column of pure water with no dissolved gas

Depth below water level	Hydrostatic fluid pressure at		BPD temperature
	20°C	BPD	
Meters	MPa	MPa	°C
0	0.00	0.00	100
10	0.10	0.09	119
20	0.19	0.19	132
40	0.39	0.36	149
60	0.58	0.54	162
80	0.78	0.72	172
100	0.98	0.89	180
150	1.47	1.32	196
200	1.95	1.75	208
300	2.93	2.57	227
400	3.91	3.37	242
500	4.89	4.16	254
600	5.87	4.93	264
800	7.82	6.43	281
1000	9.78	7.87	295
1200	11.7	9.26	306
1500	14.7	11.27	321
2000	19.6	14.40	339
2500	24.5	17.30	354
3000	29.3	19.90	365

2.5 Maximum Design Pressure

2.5.1 – Application of Maximum Design Pressure

Each casing string, liner lap, casing connection, wellhead connection, and wellhead **shall** be designed to withstand the Maximum Design Pressure for the corresponding hole section. See Figure 2 on page 18.

2.5.2 – Calculation of Maximum Design Pressure

The Maximum Design Pressure **shall** be calculated throughout the length of each hole section, and **shall** be the greatest of:

- (a) 100% of the Injection Condition, based on the maximum continuous injection pressure;
- (b) 100% of the Steam Condition; and
- (c) The Gas Condition, modified as necessary by specific engineering analysis. This may include the following factors:
 - (i) Knowledge of underground Gas Conditions from nearby wells or within the entire geothermal field
 - (ii) Ability or inability to bleed off gas to maintain a reduced WHP
 - (iii) Duration of exposure to Gas Condition.

2.5.3 – Injection Condition

The Injection Condition is the pressure applied at the surface, plus that due to the static fluid column, less dynamic pressure losses, down to the level being considered.

NOTE

- (1) This could apply while pumping into the pipe or casing in the well or into the casing-to-casing annulus during cementing operations.
- (2) The maximum injection pressure (with a well in service) will normally be managed by controlling the injection flow rate.

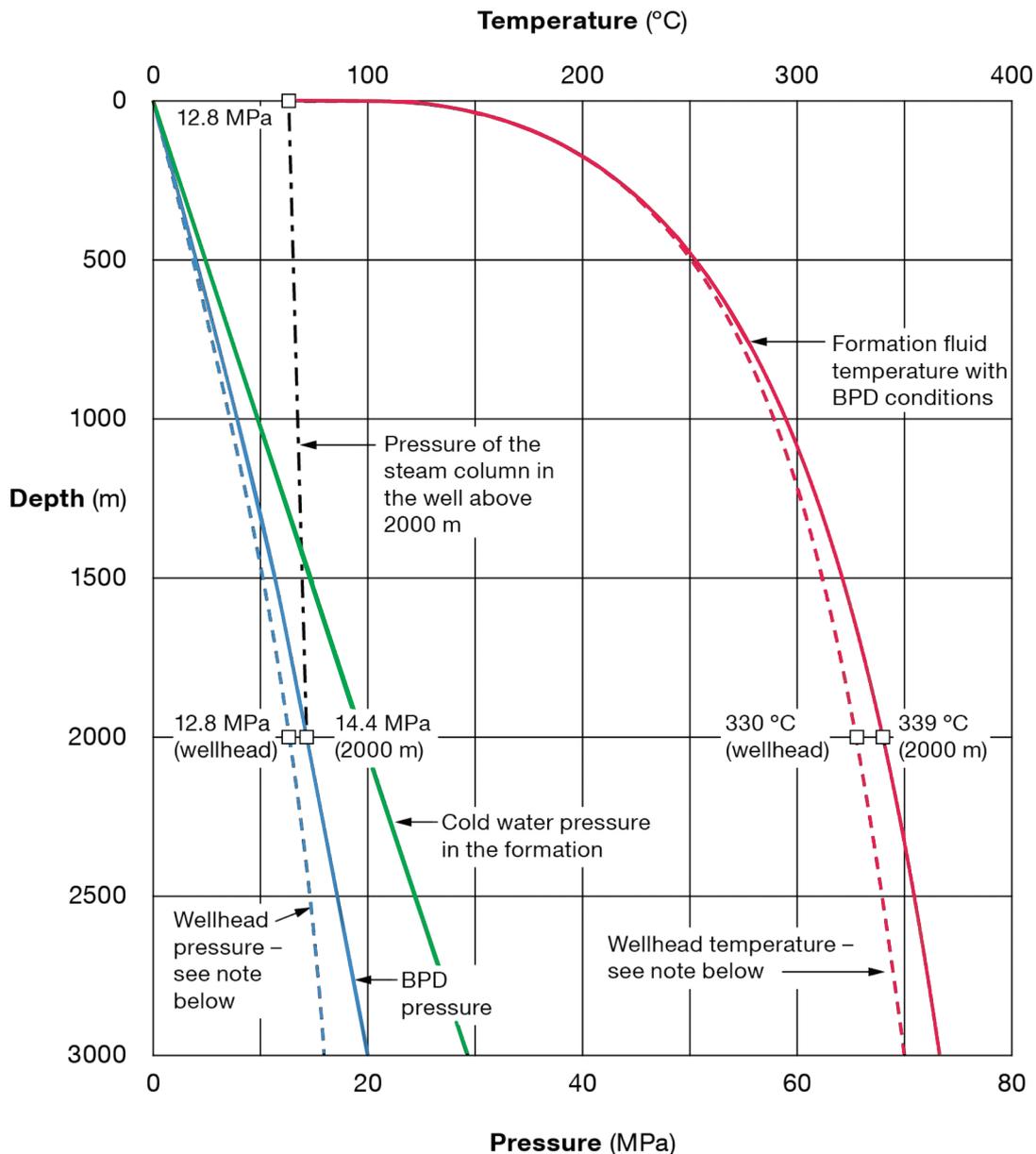
2.5.4 – Steam Condition

The Steam Condition is the saturation pressure of steam at the level of highest temperature in the open hole, less the pressure due to a column of saturated steam up to the level being considered. See the steam pressure example in Figure 3 on page 23.

NOTE

- (1) Within the well, the upper section of a liquid column could be replaced by a column of steam generated and pressure-controlled from below. Due to reduced density (and therefore pressure gradient), pressures in the upper part of the wellbore could be increased considerably above formation pressures at the same depth.
- (2) With BPD conditions, the reduction in pressure allowing for the density of steam can be ignored for moderate depths. As a proportion of the total pressure, the reduction is only 5% at 1000 m, but reaches about 20% at 3000 m for the total steam column to the surface.

**Figure 2
Downhole and wellhead fluid conditions**



Dashed lines show the Steam Conditions at the wellhead, plotted at the depth where boiling is assumed. The example shows the pressures and temperatures at the wellhead and at 2000 m, assuming boiling between 2000 m and the surface.

2.5.5 – Gas Condition

The Gas Condition is the maximum gas pressure expected over the depth of each hole section.

NOTE

- (1) The gas density is assumed to be that of CO₂.
- (2) Abnormal gas pressures occur in shallow formations above a geothermal resource.
- (3) For shut-in wells, the gas column typically extends down to the first zone of major permeability.

2.6 Pressure Containment

2.6.1 – Assessment of Effective Containment Pressure

The Effective Containment Pressure **shall** be assessed at every depth within the well, down to the production casing shoe.

NOTE

Shallow geological formations associated with geothermal resources are commonly stratified, with the possible occurrence of layers of high and low permeability. The permeable layers do not always hold pressure significantly greater than the formation pore pressure. In that case, the Effective Containment Pressure will rely on an overlying, more competent formation. The pressure containment ability within permeable zones will be governed by dissipation of the fluid within the permeable formations, and the sum of the pressure containment and fracture pressure gradient of the formations above the depth of interest.

2.6.2 – Objective of pressure containment

The primary objective of pressure containment is the prevention of well blowout to surface, through either formations, faults, or other wells, or underground.

A secondary function of pressure containment is prevention of cross-contamination of subsurface fluids.

NOTE

- (1) Where a poorly consolidated or fractured rock unit with vertically connected permeability, or structural feature (such as a fault) connects the open hole to the ground surface, the possibility of a blowout exists if the pressures in the wellbore exceed hydrostatic pressure below the groundwater level. This situation can be generated from deep in the hole, even when cooling fluid is being injected to a shallower depth.

- (2) A blowout can occur if the fluid pressure exceeds that necessary to rupture and flow into the overlying formations. Significant points relating to geothermal blowouts outside the wellhead include the following:
- (a) Escape of the well fluid to the surface can occur from quite shallow depths – less than 150 m;
 - (b) In geothermal wells interzonal flows commonly occur within the high temperature reservoir and these are not considered to be a blowout. See 1.3.2 on page 3;
 - (c) Strict adherence to classical hydraulic fracturing theory can lead to an impractical number of casing strings at shallow depths and should be specifically addressed in the well design document; and
 - (d) Enhance protection from surface eruption by setting the lowest section of each casing into formation that is structurally competent and relatively impermeable. The selection of shoe depths is aided by shallow investigation, see 3.3.1 (see page 49) but such preparation does not replace the need to review the situation as drilling progresses.

2.6.3 – Estimation of formation fracture pressure

Where the formation fracture pressure is not known, it may be estimated by using the Eaton Formula (Eaton, 1969) as follows:

$$P_{frac} = P_f + \frac{\nu}{1 - \nu} (S_v - P_f)$$

2.7 Casing setting depths

2.7.1 – Minimum casing shoe depths

The minimum casing shoe depth of each cemented casing string or liner **shall** be calculated to be the depth where the formation has sufficient Effective Containment Pressure to equal the Maximum Design Pressure expected to be encountered in the next open-hole section.

Vertical depths **shall** be used for all casing shoe setting depth calculations.

2.7.2 – Selecting design casing shoe depth

For each casing, the design casing shoe depth **shall** be set no shallower than the minimum casing shoe depth as described above. Reasons for setting the design casing shoe deeper than that minimum casing shoe depth may include:

- (a) To set the casing shoe in a competent formation;

- (b) To case out loss zones or problem zones;
- (c) To provide reservoir isolation and prevent cold inflows or unwanted interzonal communication;
- (d) To provide additional corrosion protection; and
- (e) To avoid the possibility of interference or communication with an adjacent well.

2.7.3 – Considerations for cemented liner and tiebacks

When determining design casing shoe depth for cemented liners, the following **shall** be taken into account.

- (a) Cemented liner laps **shall** be tested prior to drilling out the shoe to assure they have adequate pressure integrity for drilling the next hole section. Cemented liner laps, with or without tie-back casing, cannot be considered to provide a seal in either direction (well contents leaking out of the well or formation fluid leaking into the well) over the life of a geothermal well, but a tested liner lap can be considered to provide an adequate seal during drilling operations
- (b) Where the last cemented casing consists of a liner tie-back, consideration **should** be given to the Effective Containment Pressure of the formation at the shoe of the previous cemented casing string. Over the complete well life, the pressure within or outside the well may not be contained at the liner lap and tieback liner connection.

2.7.4 – Well casing shoe depth design process

Casing depth design **should** begin with selection of the planned maximum vertical depth for the well.

From this starting point, determine the design production casing shoe depth as specified in 2.7.1 and 2.7.2 above.

Use this design depth to determine the design shoe depth of the next casing string using the same process.

Repeat this process to determine setting depths for all remaining casing strings back to surface.

Figure 4 (see page 30) is an example of how casing shoe setting depths are established for a four-string well (including the conductor). In this example, for a vertical well depth of 2000 m, minimum vertical casing shoe depths of 1000 m, 400 m, 150 m, and 30 m are calculated.

2.8 Casing diameters

2.8.1 – Selection of casing diameter

The inside diameter of the production casing or cemented production liners **should** be selected to accommodate:

- (a) Downhole equipment, such as liners and test equipment, required to complete the well;
- (b) Drilling tools and fluids needed to drill and maintain the remainder of the well;
- (c) Desired production or injection capacity;
- (d) The diameters of fishing tools; and
- (e) Operational objectives to achieve acceptable flow velocities and pressure losses.

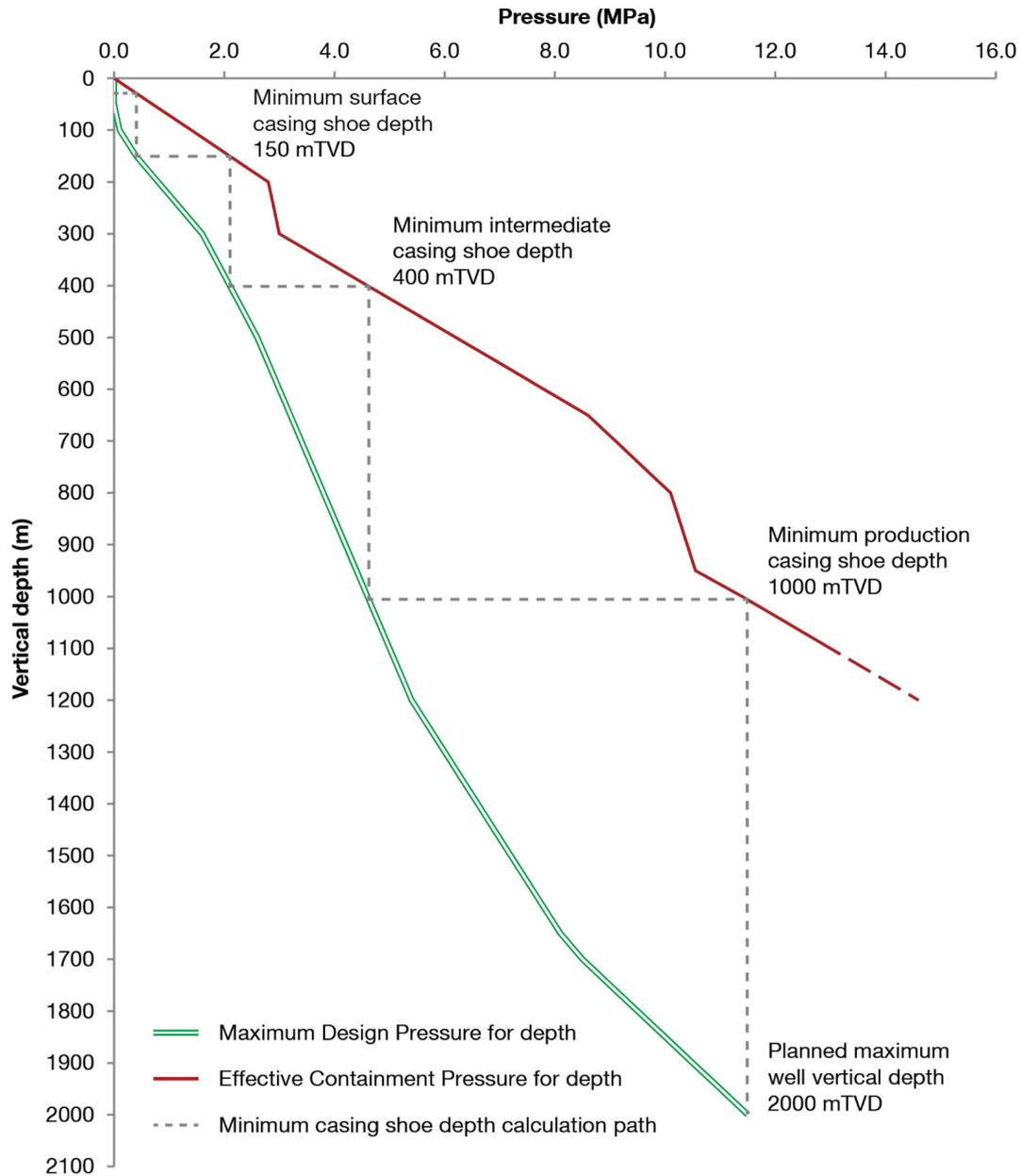
2.8.2 – Clearance between casings

Casing sizes **should** be selected to provide sufficient clearance between strings to permit satisfactory cementing of the complete casing to casing annulus.

2.8.3 – Specification of casing sizes

Casing pipe diameters **should** be selected from API Spec 5CT or API Spec 5L.

Figure 3
Example of minimum casing shoe depth selection method



2.9 Casing materials and performance properties

2.9.1 – Specifications of casing grades

Steel casings **should** be selected from API Spec 5CT or API Spec 5L.

NOTE

While low alloy steel is the predominant material used for casing, special conditions (particularly severely corrosive exposure) could warrant consideration of other products.

2.9.2 – Where gas may be present

In situations where gas may be present, casing materials **shall** be selected to minimise the possibilities of failure by hydrogen embrittlement or by sulphide stress corrosion. For resistance to H₂S attack, materials **should** be selected that are approved or conform to ANSI/NACE MR 0175/ISO 15156. Such approved API steels are:

Spec 5CT Grades: H-40, J-55, K-55; M65,
L-80 type 1, C90 type 1,
T95 type 1;

Spec 5L Grades: A and B and X-42 through X-65

The use of other API or proprietary grade steels **should** be restricted to those having metallurgical properties that have proven suitability for use in sour gas service in the petroleum or geothermal industry.

NOTE

- (1) The resistance of low alloy steel to sulphide stress corrosion is dependent on its chemical composition and on manufacturing processes including heat treatment. In general, steel having low yield strength and hardness below 22 on the Rockwell C scale demonstrate the greatest resistance. See Section 1 and 2 of ANSI/NACE MR 0175/ISO 15156 for details.
- (2) Sulphide stress corrosion is not anticipated to be a problem at high temperatures. This is because the steel has less susceptibility to such attack and tensile stresses are small. But if a well that has been exposed to H₂S at high temperatures is quenched, cracking can occur, so high temperatures cannot be relied upon to prevent cracking, unless the well is maintained forever in this condition.

2.9.3 – Specifications of other casing materials

In circumstances where low alloy API steels covered in 2.9.2 are unsuitable, alternative casing or liner materials **should** be specified. The relevant properties of the selected materials **shall** be suitable for service over the full range of expected temperatures. Evaluation of alternative materials **should** include the results of long-term tests for similar materials. Fibre-reinforced products could be considered and these **should** conform to API Spec 15HR.

2.9.4 – Effect of temperature on casing properties

Unless other values need to apply to specific steels, the coefficient of thermal expansion (a) **should** be taken as:

$$13 \times 10^{-6}/^{\circ}\text{C}$$

The thermal stress constant for casing steel held against movement is **E.a.**

If no other data is available a conservative calculation for this is:

$$210 \times 10^3 \times 13 \times 10^{-6} = 2.73 \text{ MPa/}^\circ\text{C}$$

The casing string material tensile yield and ultimate strengths **shall** be de-rated at elevated temperatures, as specified in Table 4.

Table 4
Effect of temperature on casing properties

Grade	Temperature (°C)						
	20	100	150	200	250	300	350
	API Yield Strength (Factor)						
J55/K55	1.00	0.94	0.90	0.90	0.85	0.80	0.70
L80/C90/T95	1.00	0.96	0.92	0.90	0.88	0.85	0.81
	Tensile Strength (Factor):						
All grades	1.00	0.96	0.92	.90	0.88	0.86	0.84
	Modulus of Elasticity (103 MPa)						
All grades	210	205	201	197	194	190	185
<p>NOTE</p> <p>(1) The tabulated values are generally within 5% of selected published figures.</p> <p>(2) Sufficient published test data on some of the preferred steels listed in 2.9.2 are not available for inclusion in Table 4.</p> <p>(3) Table 4 was prepared based on published data collected from companies such as Tenaris, Sumitomo, Grant Prideco, and Nippon. Some variation exists between these data sets and this table represents a realistic lower bound of the data</p>							

2.9.5 – Performance properties

For design purposes, the tables and equations set out in API publication TR 5C3 **shall** be used to calculate casing performance properties such as:

- (a) Axial strength;
- (b) Internal pressure resistance; and
- (c) Collapse resistance.

Where necessary, the performance and strength properties **shall** be modified to allow for the effects of:

- (a) Temperature;
- (b) Corrosion;
- (c) Erosion;
- (d) Wear, and
- (e) Potential for casing damage during casing installation.

2.10 Casing stress

2.10.1 – Assessing casing stress

2.10.1.1

The design of casings **shall** include consideration of the effects of all combinations of pressure, temperature, and temperature change that may occur at any time or depth during the drilling and operation of the well. Particular aspects to address include:

- (a) Room for the linear expansion or contraction of uncemented lengths of casing or liner including potential effects on a liner hanger;
- (b) For elastic design, strength required to resist thermal stresses in fixed sections and to maintain casing and casing connection sealing integrity;
- (c) For a strain-based plastic design, adequate sealing integrity at connections (see 2.10.1.4);
- (d) For a strain-based plastic design, stress concentrations from material property or dimensional variations that can lead to low cycle fatigue or failure; and
- (e) Provision for the thermal expansion of liquids.

2.10.1.2

Casing stresses **shall** be assessed either by:

- (a) Calculating each individual stress, using the methods in 2.10.2, 2.10.3, 2.10.4, and 2.10.5; or
- (b) Calculating the triaxial stress using API TR 5C3, or equivalent methods. The triaxial stress calculation combines all the stresses acting on the casing, as listed in (i) to (iv) to derive the maximum equivalent stress:
 - (i) Radial and circumferential stress as determined by the Lamé Equations for a thick cylinder

- (ii) Uniform axial stress due to all sources except bending
- (iii) Axial bending stress for a Timoshenko beam
- (iv) Torsional shear stress due to a moment aligned with the axis of the pipe.

For triaxial design the design factor is:

$$\frac{\text{minimum material yield stress}}{\text{maximum total equivalent triaxial stress}}$$

The stress calculations in 2.10.2, 2.10.3, 2.10.4, and 2.10.5 and the triaxial stress calculation are all based on maximum stress in the casing being limited to the yield strength of the casing including the specified design factor. Individual stress calculations and the triaxial stress calculation are not applicable to a strain-based or plastic design, in which case the associated design factors **should** not be used. Strain-based or plastic designs for thermally induced axial stresses are discussed in 2.10.3.4 (see page 32).

2.10.1.3

External pressure collapse and axial buckling may not be the result of exceeding the material yield stress. These types of failure **shall** be considered as a separate calculation from the triaxial stress calculation. See 2.10.5 (see page 36) for the calculation of the net external (collapse) pressure and the comparison to the casing collapse strength.

2.10.1.4

Where two or more materials are to be used together in casing strings, the design **shall** take into account the relative coefficient of thermal expansion of each material.

NOTE

The magnitudes of thermal effects are illustrated by the following examples:

- (a) For a 1000 m length of steel casing and a 150°C temperature rise, the free expansion approximates to 1.8 m;
- (b) The compressive stress induced in this case by preventing the expansion is 409 MPa. By comparison, Grade K-55 casing steel has a minimum yield strength of 379 MPa.

2.10.1.5

If it is expected that thermal stresses will approach or exceed the yield strength of the casing material, casing connections **shall** be selected to have sufficient strength to match or exceed the pipe body yield strength in both compression and tension. Such consideration of connection strength **shall** take into account the effect of elevated temperature.

NOTE

- (1) Axial failure commonly occurs at or adjacent to a casing connection when heavily loaded, V-shaped threads tend to separate radially by a wedging action before slipping longitudinally in a mechanism known as 'unzipping'. Square thread forms and shouldered connections fail in compression by bulging of the thinner pipe or coupling section. Connection features such as pin to pin abutment or shouldered couplings can provide additional compressional strength.
- (2) Only tensile strengths are listed for casing connections in the API bulletins and most proprietary data sheets.
- (3) 100% connection gas tightness is not considered a primary requirement for geothermal service. If the well designer considers gas tightness to be essential, casing connections for the production casing string should be selected to maintain gas-tight sealing when thermally cycled at ranges of temperatures up to the expected production temperature.

2.10.1.6

The effects of plastic yield and of stress relaxation with time **should** be considered where plastic yielding is expected. Assessment of tensile forces during well quenching **should** assume that casing stresses have been neutralised over time with the well's normal state – that is, shut-in, bleed, or production.

NOTE

Initial well heating induces compressive stresses in cemented casing. It may be assumed these stresses decrease with time, at rates which may be significant at high temperatures and stress levels, and which vary with the microstructure of the particular casing material. Stress reduction under this mechanism tends to take place over weeks and months. Due to this stress reduction, subsequent cooling of a fully heated well may develop higher tensile stresses than occurred when the casing was installed (see 2.10.3.3 on page 32).

Where plastic yielding is expected, the design should consider the effect of low cycle fatigue cracking.

2.10.2 Assessing axial loading before and during cementing

2.10.2.1

Until the annular cement sets around the casing, the tensile force at any depth **shall** be calculated by considering the weight in air of the casing materials, plus the weight of the casing contents, less the buoyant effect of any fluid displaced by the casing. This is defined as follows:

$$F_{hookhand} = F_{csg\ air\ wt} + F_{csg\ contents} - F_{displaced\ fluids}$$

Where:

$$F_{csg\ air\ wt} = L_z \cdot W_p \cdot g \times 10^{-3}$$

$$F_{csg\ contents} = \sum \rho_{if} \cdot L_{if} \cdot \frac{\pi d^2}{4} \cdot g \times 10^{-6}$$

$$F_{displaced\ fluids} = \sum \rho_{ef} \cdot L_{ef} \cdot \frac{\pi D^2}{4} \cdot g \times 10^{-6}$$

NOTE

It is possible that $F_{hookhand}$ can be negative. In this instance the casing is floating and can be forced from the well. Under these circumstances, steps should be taken to hold the casing down against this flotation.

2.10.2.2

The difference between the air weight of the casing ($F_{csg\ air\ wt}$) and the hookload ($F_{hookhand}$) is the applied Bouyancy Force ($F_{buoyancy}$). Positive Bouyancy Force acts downwards, and negative Bouyancy Force acts upwards. This is calculated as:

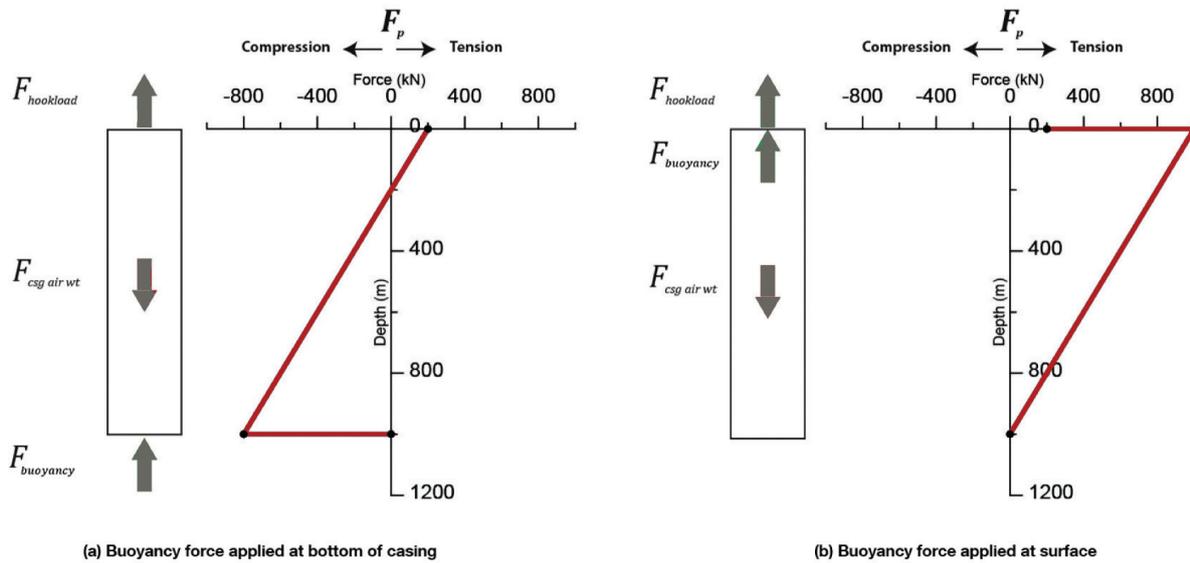
$$F_{buoyancy} = (F_{hookhand} - F_{csg\ air\ wt}) = (F_{csg\ contents} - F_{displaced\ fluids})$$

Unless a more detailed assessment is required, the Bouyancy Force **should** be considered to be applied as a point load at the depth within the casing that is holding differential pressure. Typically this is either at the float collar or float shoe, or at surface.

2.10.2.3

The force at any point in the casing under hydraulic and gravitational loads prior to cement setting – defined as F_p – can be assessed to be the applied point loads, $F_{hookhand}$ and $F_{buoyancy}$ and the air weight of the casing from surface down to the depth of interest. (See Figure 4 on page 30.)

Figure 4
Example of casing forces calculation before cement set for situations where the Buoyancy Force is applied at the bottom of the casing (Figure 4a) and where it is applied at surface (Figure 4b). For this example, $F_{buoyancy} = -800$ kN and $F_{csg\ air\ wt} = 1000$ kN. Both examples have $F_{hookload} = 200$ kN, but have different internal forces.



2.10.2.4

In addition to the static loads, the design tensile force *should* allow for:

- (a) Dynamic loads imposed during the running of casing. These loads result from acceleration as the string is raised from rest to hoisting speed, or deceleration due to braking or setting in slips; and
- (b) Drag forces arising from the casing acting against the side of the wellbore, acting opposite to the direction of travel.

2.10.2.5

In a non-vertical, curved hole the maximum bending stress induced is:

$$f_b = 0.291 \times E \times q \times D \times 10^{-6}$$

This stress is applied both as additional compressive stress at the inside of the arc, and additional tensile stress on the outside of the arc. These additional stresses **shall** be added to the casing stress created by weight, hydraulic loads and thermal loads.

2.10.2.6

The design tensile force **shall** also include any pre-tensioning of the upper section of the string that may be applied after anchoring the shoe (generally by primary cementing), in order to reduce later compressive stresses due to heating.

2.10.2.7

These axial loadings applied before cementing **shall** be added together where they can apply simultaneously. Where the minimum strength to be used is the lesser of the pipe body or casing connection values, the design factor is:

$$\frac{\text{minimum tensile strength}}{\text{maximum tensile load}}$$

2.10.3 Assessing axial loading after cementing

2.10.3.1

Axial forces imposed after cementing **shall** be checked for applicability and magnitude near both the top and the shoe of the casing string. To calculate the resultant net or total force, each of the loadings **shall** be combined with the static force present in the casing at the time of the cement setting. If the stress calculated in 2.10.3.2 or 2.10.3.3 exceeds the yield stress, a plastic/strain-based design will be required.

Normally, the static force present is F_p as calculated in 2.10.2.1. Stresses are represented in Figure 5 on page 33.

2.10.3.2

The change in axial force (with tension as positive) due to temperature rise in situations of partial longitudinal and lateral constraint is:

$$F_c = E.a(T_1 - T_2)A_p \times 10^{-3}$$

The resultant force is: $F_r = F_p + F_c$

If the resultant stress exceeds the material yield stress then consideration **shall** be taken of 2.10.3.4.

NOTE

At dog-leg sections of the wellbore compressive forces in the casing will increase and these forces are added to the thermally-induced compressive loading on the casing. The potential for thinning of the casing at these dog-leg sections due to drilling operations needs to be considered in the design.

2.10.3.3

Ignoring any relaxation of stress with time, the temperature reduction when cool fluid is circulated from the surface during subsequent drilling, testing or reinjection operations causes a change in axial tension that is:

$$F_t = E.a(T_1 - T_3) \times A_p \times 10^{-3}$$

At every depth except close to the wellhead, the resultant force is $F_r = F_p + F_t$.

If the resultant stress exceeds the material yield stress then consideration shall be taken of 2.10.3.4.

NOTE

If the well has been at elevated temperatures for an extended time, the stresses are likely to have been significantly reduced by creep. Under most circumstances, stresses (both the plastic and elastic) would be expected to be at or below yield. In this instance, T_1 should be replaced by T_2 in the calculation.

2.10.3.4

Conventional design factors are not applicable for casing that is designed to yield. If the casing is expected to thermally yield during operations, it **shall** be designed to accept limited plastic strain, taking into consideration stress relaxation, cyclic hardening and strain localisation effects.

NOTE

- (1) Casing design can be assessed for suitability by comparing the design against Appendix E of *Industry Recommended Practice Volume IRP3-2012* (Enform Canada). Appendix E provides guidance to show how stresses may be assessed over multiple thermal cycles. Holliday, 1969: 'Calculation of Allowable Maximum Casing Temperature to Prevent Tension Failures in Thermal Wells' provides calculation methods to verify casing is suitable. Take into account that this paper did not recognise that stress relaxation could occur above 200°C.
- (2) Axial strains of $\leq 0.5\%$ are not considered a concern for low cycle fatigue (Enform Canada, IRP3 2012).

2.10.3.5

Consideration of unbalanced forces **should** be taken into consideration for connections between casings of differing cross-sectional areas.

The thermal forces are both multiplied by and divided by the cross-sectional area. If two casings have different cross-sectional areas, this will cause a greater force to be applied to the weaker member and will result in a greater stress above thermal loading stresses.

2.10.3.6

The tension occurring at the top of any string that anchors a wellhead against the lifting force applied by the fluid in the well is:

$$F_w = \frac{\pi}{4} \times P_w \times d^2 \times 10^{-3} - F_m$$

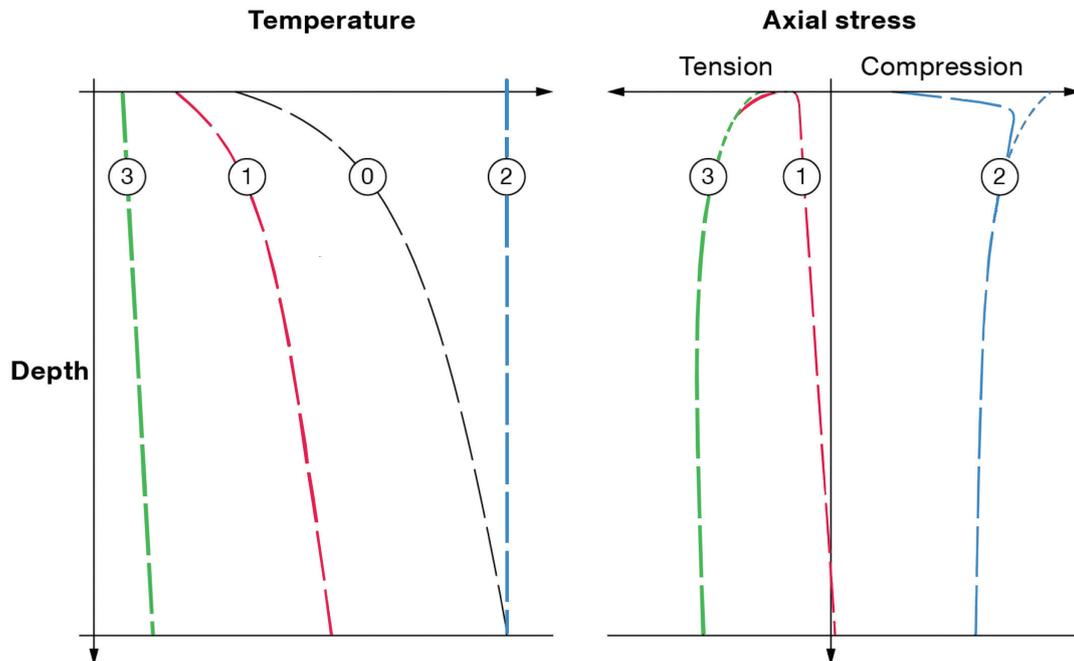
To allow for variation in steel strength with temperature change, both the hot (steam) and cold (gas) wellhead conditions **shall** be checked. The design factor in 2.10.2.7 applies.

Alternatively, this load may be considered together with hoop stresses in a biaxial stress analysis, as described in 2.10.5.4. See Figure 5.

NOTE

This does not negate the need to calculate the maximum differential internal pressure under 2.10.6.3 (see page 37).

Figure 5
Casing stress dependence on temperature



See **Figure 5 Note** on next page

Figure 5 Note

The curves are examples of the following conditions:

Curve 0: In undisturbed formations;

Curve 1: At cement set, with casing suspended on hook;

Curve 2: At maximum temperature, with steam in well; and

Curve 3: At minimum temperature, while Injecting or circulating cold fluid.

2.10.3.7

A lifting force may be applied to the anchor casing by the thermal expansion of another casing string where the mechanical design allows it to interfere with a part of the wellhead. In such cases, the integrity of the anchor casing and wellhead **shall** be protected by ensuring that any failure occurs elsewhere. The design factor is:

$$\frac{\text{anchor casing tensile strength}}{\text{rising casing compressive strength}}$$

NOTE

- (1) In practice this usually applies where there is a poorly cemented production casing inside the anchor casing, so that the upper part of the production casing is free to expand. Where the length of uncemented casing can be determined (for example, by cement bond log) the practical solution is to remove sufficient length of the production casing that the expanding free end cannot reach the casing head flange (CHF).
- (2) The minimum tensile strength is likely to be the connection between the top of the anchor casing and the CHF.

2.10.4 – Assessing axial loading of uncemented liners with buckling and bending

2.10.4.1

Uncemented liners, either hung in tension from the liner top or supported at the shoe in compression, **should** either:

- (a) Allow for thermal expansion at the free end; or
- (b) The liner **shall** be designed to resist any additional buckling forces imposed.

Wherever a liner or casing is not completely restrained radially, it **should** be analysed for helical buckling.

NOTE

Hung liners could be more difficult to set and retrieve than bottom-supported liners as mineral deposition can prevent the release of the hanger. Also, the necessary allowance for thermal expansion prevents the bottom of the hole being protected by a tension liner. But buckling and compressive stresses would not occur in a hung liner.

2.10.4.2

The total extreme fibre compressive stress in an uncemented liner subject to axial self-weight and helical buckling is:

$$f_c = L_z \times W_p \times g \times \left[\frac{1}{A_p} + \frac{De}{2I_p} \right]$$

NOTE

Where an uncemented liner is subject to compressive stressing (for example, a perforated liner supported at hole bottom) the pipe will bend slightly, within the limits set by the wall of the hole, and will assume a mildly helical position. The ratio of the hole diameter to the pipe diameter will determine the amount of bending and therefore the bending stresses.

The design factor is:

$$\frac{\text{minimum yield stress } \times R_j}{\text{total compressive stress}}$$

where R_j does not exceed 1.0.

NOTE

- (1) Buckling (particularly that due to temperature rise with end constraint) can occur when there is insufficient lateral support due to oversized or washed out hole;
- (2) See 2.10.1.4 (see page 27) for guidance on casing connections and connection strengths.
- (3) In some circumstances it could be acceptable to allow a liner to be stressed above yield stress, provided this does not have a significant detrimental effect on the well integrity.

2.10.4.3

Perforated liners *should* be designed with due allowance for the weakening of the pipe section resulting from:

- (a) Reduction in effective cross section and section modulus;
- (b) Stress concentration where there is a dog-leg in the wellbore; and
- (c) Reduction in steel strength due to the perforating process.

NOTE

Some flame-cutting methods can induce micro-cracking of the casing steel. Punching causes local stress concentrations.

2.10.5 – Assessing hoop stresses

Hoop stresses from the following causes **shall** be considered:

- (a) The difference between the pressures inside and outside the casing before and during cementing operations;
- (b) Well fluid pressures in the static condition or when producing or injecting.
- (c) Temperature changes with restraint on movement;
- (d) Heating of a confined liquid; and
- (e) Dynamic loading.

NOTE

In the static condition, the formation fluid pressure at any drilled depth can be reflected at any higher level by a column of steam or gas in the well. See Figure 2 on page 18.

2.10.6 – Hoop stressing – Internal yield

The design **shall** ensure an adequate safety margin against yield arising from high internal fluid pressure due to any of the following:

- (a) Surface pressure plus a static fluid column;
- (b) Thermal expansion of trapped liquid;
- (c) Well pressures generated from the formation; and
- (d) A combination of the effects in (a) to (c).

NOTE

For (b), because the coefficient of thermal expansion of water is not constant the effect of heating water in a confined space is best calculated using values derived from the steam tables. At temperatures above 100°C the pressure change due to changing temperature approximates to 1.6 MPa/°C.

2.10.6.1

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NOTE

For (b), because the coefficient of thermal expansion of water is not constant the effect of heating water in a confined space is best calculated using values derived from the steam tables. At temperatures above 100°C the pressure change due to changing temperature approximates to 1.6 MPa/°C.

2.10.6.2

During cementing the maximum differential internal pressure of the string occurs near the shoe or stage cementing ports when all of the following apply:

- (a) The casing is filled with cement slurry;
- (b) The annulus contains either a column of water or is subject to formation pressure; and
- (c) There is sufficient constriction within the casing (for example, a cementing plug) to hold the differential pressure.

The maximum differential internal pressure is:

$$\Delta P_{internal} = [L_z \rho_c - L_f \rho_f] \times g \times 10^{-3}$$

The design factor is:

$$\frac{\text{internal yield pressure}}{\text{differential internal pressure}}$$

NOTE

The internal yield pressure can be exceeded if sufficient pressure is applied at surface to the inside of the casing. For design purposes, this is not considered, but operationally, any additional applied pressure must be limited to prevent exceeding the internal yield pressure of the casing.

2.10.6.3

After cementing, the maximum differential internal pressure will occur at the surface. Two cases **should** be considered, namely:

- (a) With steam at the wellhead, the design factor is:

$$\frac{\text{Internal yield pressure} \times R_i}{\text{wellhead pressure}}$$

- (b) With cold gas at the wellhead, when the stress corrosion tensile limit of the steel **should** be used to determine the appropriate yield strength.

2.10.6.4

If the wellhead is fixed to the casing being considered, a biaxial stress condition exists. The combined effects of axial and circumferential tension **shall** be calculated from the following expression:

$$f_t = \frac{\sqrt{5}}{2} \times \frac{P_w d}{(D - d)}$$

The design factor is:

$$\frac{\text{steel yield strength}}{\text{maximum tensile stress}}$$

2.10.7 – Hoop stressing – Collapse

2.10.7.1

The casing design *should* ensure an adequate margin of safety against pipe collapse occurring due to external pressure from entrapped liquid expansion, or to applied pressure or static pressure from a heavy, liquid column such as cement slurry, and possibly considered in combination with axial stresses in a biaxial stress analysis.

2.10.7.2

During the later stages of the casing cementing operation, the maximum differential external pressure occurs near the casing shoe when the casing annulus is filled with dense cement slurry, and the casing is filled with water. The maximum differential external pressure is:

$$\Delta P_{\text{external}} = [L_z \rho_c - L_z \rho_f] \times g \times 10^{-3}$$

In this case the design factor is:

$$\frac{\text{pipe collapse pressure}}{\text{differential external pressure}}$$

NOTE

- (1) The collapse pressure can be exceeded if sufficient pressure is applied at surface to the outside of the casing. For design purposes, this is not considered, but operationally, any additional applied pressure must be limited to prevent exceeding the collapse pressure of the casing.
- (2) If there is a possibility that the water inside the casing cannot be prevented from boiling, assume ρ_f is zero.
- (3) Compressive loads on the casing shoe due to buoyant forces could serve to strengthen the collapse pressure of the casing.
- (4) The maximum pressure possible from the thermal expansion of a trapped liquid far exceeds the strengths of normal casing strings in either burst or collapse. Reinforcement of the outer casing by cement and formation means that the failure mode is almost always a collapse of the inner casing. To avoid this failure mode make every effort to prevent trapped liquid between casing strings during cement placement.

2.10.7.3

During production operations, the maximum external differential pressure occurs near the casing shoe when the annulus is at formation pressure ($P_z = P_f$) and the internal pressure is controlled by well drawdown. In the worst case the internal pressure at the casing shoe can approach the operating wellhead pressure.

In this case the design factor is:

$$\frac{\text{pipe collapse pressure}}{\text{differential external pressure}}$$

The pipe collapse strength is de-rated for the temperature at the shoe.

2.10.8 – Providing for reduction in cross-sectional area

2.10.8.1

Stress analysis **shall** take into account the gradual reduction in the effective cross-sectional area of competent material by wear, erosion, and corrosion.

NOTE

- (1) With constant load, this reduction will increase the stress on the remaining material.
- (2) Erosion and wear can be caused by the rotation of hard-faced tools during drilling, or by the action of abrasive rock during either drilling or fluid production.

2.10.8.2

Where casing erosion threatens the integrity of the well, the following measures **should** be among the options considered:

- (a) Reducing velocities or turbulence;
- (b) Reducing particle quantities and aggressive properties; and
- (c) Providing sacrificial thickness, or a sacrificial liner.

2.10.8.3

The following corrosion-related effects **shall** be considered:

- (a) External surface attack of steel and cement grout by aggressive groundwater and gas, including areas near water level where the presence of oxygen accelerates the rate of chemical action; and
- (b) Stress corrosion cracking in the presence of cold, wet hydrogen sulphide gas, which induces a reduction in the strength of casing steel when under high tensile loading.

NOTE

When completely closed, a well with high gas content tends to stabilise with a column of cold gas (predominantly CO₂ and H₂S) down to a level at or below the casing shoe. This situation also favours high tensile stressing due to temperature decrease.

2.10.8.4

Where conditions are likely to cause corrosion of the casing, adequate measures **shall** be taken to maintain the integrity of the well. These may include the following:

- (a) The provision of sacrificial thickness or sacrificial liner to achieve the required casing life;
- (b) The application of a resistant covering over the casing surface;
- (c) The choice of a casing material other than low alloy steel – such as titanium or chromium-based or nickel-based alloys, or glass fibre reinforced thermosetting resin; and
- (d) Limiting the well design life.

2.10.9 – Design factors when assessing casing stresses

The minimum casing design factors are summarised in Table 5.

2.10.10 – Combination strings

A casing string may consist of a combination of lengths having different specifications. Any crossover connections between sections **shall** comply in all respects with this code.

Table 5
Minimum design factors

Stress Condition	Load case	Section	Minimum Design Factor
Triaxial	As per application and caveats in 2.10.1.2	2.10.1.2	1.25
Axial	Tensile force during running and cementing casing	2.10.2.7	1.80
	Fluid lifting force on anchor casing	2.10.3.6	1.80
	Thermal load on anchor casing (where applicable)	2.10.3.7	1.40
	Helical buckling due to self-weight plus thermal load (uncemented liner)	2.10.4.2	1.00
Hoop	Internal pressure at shoe during cementing	2.10.6.1	1.50
	Wellhead internal pressure (shut-in steam/gas after drilling)	2.10.6.2	1.80
	Wellhead internal pressure (shut-in steam/gas after drilling) where wellhead is fixed to the casing	2.10.6.3	1.50
	External pressure collapse (during cementing)	2.10.7.1	1.20
	External pressure collapse (during production)	2.10.7.2	1.20

2.11 Permanent wellheads

2.11.1

Wellhead components covered by this code

The components of the permanent wellhead covered by this code are:

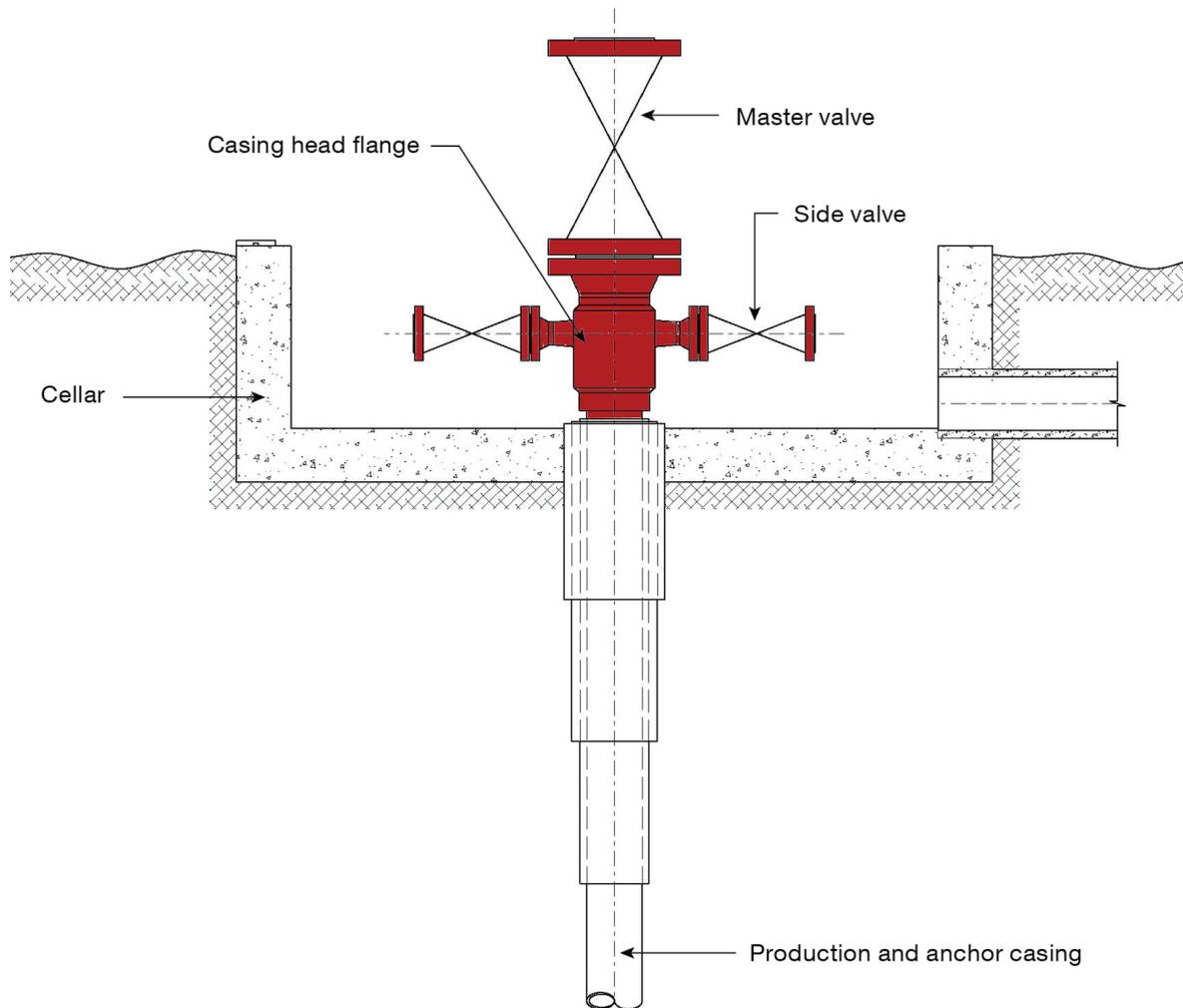
- (a) The outer flanges of the master valve directly exposed to the fluid in the top of the well;
- (b) The outer flanges of the primary side valves directly exposed to the fluid in the top of the well; and
- (c) The bottom of the CHF attaching the wellhead to the casing, plus any spools or other components included between these items.

NOTE

The preferred wellhead configuration is for two side valves. For wells completed with 9-5/8" or larger production casings, side valves of at least 3" through-bore diameter are recommended to allow suitable water injection rates needed to quench some wells.

Figure 6 illustrates a typical wellhead for permanent installation. For drilling wellheads, see Section 5 starting on page 79.

Figure 6
Typical permanent wellhead



2.11.2 Wellhead specifications

Wellheads **shall** be designed for the pressure and temperature service described in 2.5 (see page 17) and **shall** conform to API Spec 6A or API Spec 6D.

2.11.3 Wellhead component materials

The materials used in the wellhead components **shall** be suitable for use under all expected service temperatures, pressures, and other conditions (see Figure 3 on page 23). The pressure ratings of flanges conforming to ANSI B16.5 and to API 6A are plotted versus temperature in Figure 8 (see page 70).

NOTE

Materials with substantial copper content are normally unsuitable where chemical attack by an H₂S rich environment is a possibility.

2.11.4 Wellhead design factors

2.11.4.1

Where appropriate the design **shall** include provision for:

- (a) The corrosive environment that may exist around the wellhead;
- (b) The need to minimise the rise and fall of wellheads during operation;
- (c) The orientation of wellhead equipment relative to waste sumps; and
- (d) The attachment of surface pipework to the wellhead components.

2.11.4.2

The design of the wellhead **shall** assume that at least the top 25 m of each casing string will expand freely throughout their expected temperature range, without interference from projecting components anchored to other casing strings.

2.11.4.3

The wellhead design **shall** include means to protect the surfaces of the wellhead and casing tops from the corrosive effects of well fluids and of the atmosphere (see also 5.11.4.1 on page 101).

NOTE

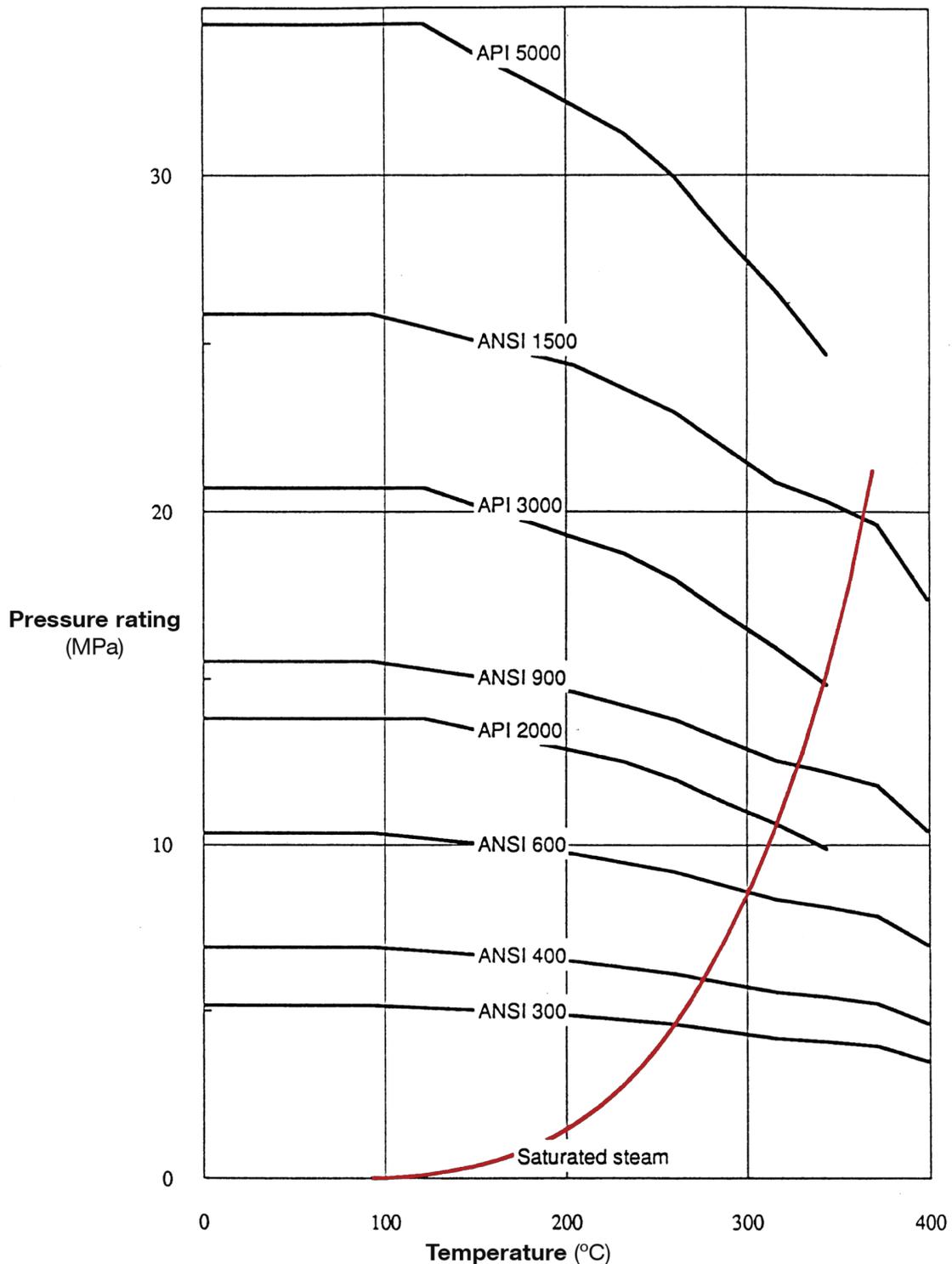
Additional protection could come from:

- (a) Improvement of the environment – such as clearing gas;
- (b) Isolation of the critical components from the corrosive environment, by glanding and/or by filling the surrounding space with inert material – for example, cement grout;
- (c) Coating the surface with a resistant film – for example, epoxy resin; and
- (d) Raised face flanges – these reduce the corrosion rate of bolting or studs and allow for easy visual assessment of such corrosion.

2.11.4.4

Wellhead components **shall** be designed for the pressure and temperature conditions described in 2.5 and de-rated for temperature (see Figure 7).

Figure 7
Wellhead working pressure de-rating for flanges and valves conforming to ANSI B16.5 and to API 6A



2.11.5 Wellhead flanges

2.11.5.1

For ratings ANSI 400 and above, all wellhead components *should* be bolted together through ring-jointed flanges. Only if otherwise unavoidable *should* studded connections be used on any part of the permanent wellhead.

2.11.5.2

The preferred method of connection of the CHF to the anchor casing is by casing threading for the sizes and API pressure ratings set out in Table 6:

Table 6
Recommended pressure limits for threaded CHFs

Casing size	Pressure rating
4-1/2" to 10-3/4"	Up to 5000 psi (34.5 MPa)
11-3/4" to 13-5/8"	Up to 3000 psi (20.7 MPa)
16" to 20"	Up to 2000 psi (13.8 MPa)

Where the design pressure exceeds these values, the wellhead *should* be connected using a weld-on CHF.

2.11.5.3

Where the CHF connection to the anchor casing is by threading, the connection threads *shall* be strong enough to fulfil all anticipated service conditions.

NOTE

Where the connection is by threading, thread-locking of this connection should be avoided.

2.11.5.4

If welding is used to connect the CHF to the casing, it *should* be conducted using a procedure appropriate to the materials and by welders qualified in that procedure. If H₂S might be present, welding *shall* conform to ANSI/NACE MR 0175/ISO 15156. All welds *shall* be inspected and tested for defects including the ability to seal against an applied pressure equal to the Maximum Design Pressure that the section will be exposed to. Wherever possible, the weld also be tested for weld porosity. Any defects *shall* be ground out to good base metal, re-welded, and retested.

2.11.5.5

ANSI and API bolted flanges have similar dimensions – and can typically be mated together, but their different steel grades result in different pressure ratings. This applies to the flange sizes set out in Table 7:

Table 7
API/ANSI flange compatibility (non-exhaustive list)

API 6A	ANSI
9" x 3000 psi	8" Class 900
11" x 2000 psi	10" Class 600
11" x 3000 psi	10" Class 900
11" x 5000 psi	10" Class 1500
13-5/8" x 2000 psi	12" Class 600
13-5/8" x 3000 psi	12" Class 900
NOTE: API 13-5/8" 5000 psi cannot mate to ANSI 12" Class 1500.	

2.11.5.6

When ANSI and API equipment are bolted together, the lowest pressure rating **shall** be used in the design calculations.

2.11.6 – Wellhead valves

2.11.6.1

The entire wellhead (including master valve, expansion spools, and CHF) **shall** allow for a clear bore diameter at least 1/8 inch (3 mm) larger than any tool expected to be run into or through the valve.

2.11.6.2

Expanding gate valves **should** be specified for any well that, during discharge, is likely to produce fluids or particulate matter with the potential to erode any exposed gate seats.

2.11.6.3

Valve sealing **should** be accomplished by metal-to-metal seals. Where elastomeric materials are used as a secondary seal, the elastomeric material **should** be suitable for the ambient conditions to which it may be exposed.

2.11.6.4

Valves which can indicate externally the position of the valve gate **shall** be used for master valves.

2.11.6.5

Valves **should** be designed to allow repacking or secondary sealing of the stem seals while remaining in service.

2.11.6.6

Valves **shall** be specified, installed, and operated to prevent trapped fluids inside the valve cavity from fracturing the valve body. Expansion of fluids trapped in the valve body through heating or freezing can initiate failure of the valve.

Mechanical pressure relief valves or bursting disks could be used to protect the valve cavity from over-pressure. These valves or disks may not function correctly as a result of corrosion, mineral deposition, or deterioration over time, so routine inspection and maintenance is recommended.

2.11.6.7

Where there is a permanent hang-down casing or other tubing string installed through the master valve that prevents the valve being shut, consideration **shall** be given in the design and operational procedures to enable primary well isolation.

2.12 Review and modification of well design during drilling

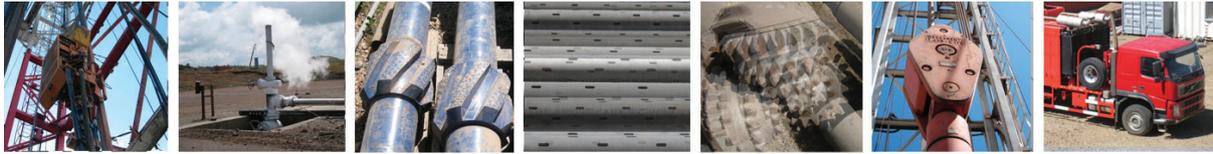
During well construction, the well design **shall** be reviewed for safety and modified if required if any of the following conditions are encountered during drilling:

- (a) Downhole fluid conditions such as temperature, pressure or gas that may create pressures greater than the Maximum Design Pressure as calculated for the initial well design.
- (b) Downhole formation conditions such as faults or weak formations that may indicate the Effective Containment Pressure is less than the values used for the initial well design; and
- (c) Casing setting depths are materially changed from the depths used for the well design (for instance, if a casing hangs up and must be cemented shallower than the design depth).

2.13 Well design records

The well owner **shall** maintain a permanent record of each well design including:

- (a) The design inputs and assumptions made using those inputs;
- (b) The design steps followed;
- (c) The safety factor calculations; and
- (d) Any specific engineering that varies from the well design prescribed in this section.



3 WELL SITES

3.1 In this section

Section 3 covers the requirements for the selection, assessment, design, construction, and maintenance of well sites. This includes infrastructure such as access roads, drainage systems, waste holding ponds, and water supplies.

3.2 Well site access

Roading, bridges, and culverts **shall** be provided and maintained to enable continuous access to the site for the drilling rig and associated equipment at all times during the drilling of the well. Following well completion, and until the well is abandoned, site access **shall** be maintained to a standard that:

- (a) Allows safe access for normal well logging and maintenance activities by light vehicles; and
- (b) Can be readily reinstated to a condition allowing for the access of a rig or other equipment to work over the well.

NOTE

- (1) Design of site access road grades, alignment, and drainage needs to allow for the transport of the dimensionally large and heavy unit loads of the drilling rig equipment.
- (2) Where existing culverts or bridges are used for site access, and they are not under the control of the local roading authority or do not have published load capacity limits, check their loading capacity against the type, size, and weight of all expected loads. Where necessary, applied loads may need to be reduced or the bridges or culverts strengthened.

3.3 Well site selection

3.3.1 Appraisal

Well site selection **shall** include an appraisal to assess soil bearing capacity and likely shallow drilling conditions. In new areas, or where there is inadequate information from other nearby sites, this appraisal **should** include shallow wells to assess near-surface geotechnical and thermal conditions.

NOTE

Geothermal well sites are commonly located in areas dominated by volcanic soils that present the following potential problems:

- (a) Light, uncompact, uncemented soils offer low bearing strength and can be susceptible to rapid erosion by natural run-off or uncontrolled drainage from the site;
- (b) Shallow sinkholes or underground caverns could be present due to acid leaching or flow of groundwater;
- (c) Low strength weathered or hydrothermally altered (for example, clay-rich) volcanic ash has poor bearing capacity and is susceptible to the occurrence of large slips;
- (d) Soils could liquefy when vibrated; and
- (e) Mineral deposition can create thin, cemented layers above material with low bearing capacity. The cemented layer can collapse when subjected to surface loading.

3.3.2 – Considerations in selecting well sites

3.3.2.1

Well site selection **shall** consider surface thermal activity and the geology in the immediate vicinity of the location. These factors can affect site construction, the long-term suitability of the site, and drilling operations.

NOTE

- (1) Warm and steaming ground presents gas and scalding hazards.
- (2) Wells located close to steaming ground often suffer from rapid corrosion of wellhead and near-surface casing. This results from elevated atmospheric H₂S concentrations or acidic subsurface conditions.
- (3) The operation of construction equipment over hot ground where caverns could be present exposes operators to the extreme hazard of ground collapse into hot fluids.
- (4) Where near-surface temperatures are close to boiling, removal of overburden and consequential lowering of the groundwater level can initiate a localised eruption of steam and mud.

3.3.2.2

The well site **shall** be selected to have sufficient open surroundings to allow dispersion of dangerous gases originating from the well.

NOTE

- (1) Where possible, avoid topographically low areas.
- (2) Gas hazards could be increased by dense forestry and shelter belts which limit the free movement of air.

3.3.2.3

Well site selection **shall** take into account requirements for lighting spill management (that is, management of luminescence), and for noise abatement during the drilling and well test operations.

3.4 Well site design and construction

3.4.1 Considerations in well site design and construction

The site **shall** be designed and constructed to:

- (a) Support all loads imposed by the drilling equipment and associated plant (such as cranes);
- (b) Control run-off and contain drilling fluids during drilling operations;
- (c) Review the geotechnical assessment during site preparation and carry out additional remedial work as required;
- (d) Consider consolidation grouting, where subsurface conditions warrant. See Appendix A (starting on page 127) for further guidance on consolidation grouting.
- (e) Have finished grades in the site area covered by the drilling rig within tolerances specified in the rig equipment OEM documentation. Outside this area, the surface of the site **should** be finished to grades that provide controlled drainage.

3.4.2 Geotechnical investigation

Geotechnical investigation **shall** be carried out during site construction, upon completion of site construction, or following any subsequent remediation works to ensure works carried out accord with the well site design specification and, in particular, with relevant load bearing requirements.

3.4.3 Managing run-off

It is good practice during drilling operations to manage and treat run-off within the site.

On completion of drilling, adjust site grades as necessary to achieve the requirements of 5.11.5 (see page 102).

3.4.4 Mast guy anchors

Where the drilling rig requires the installation of mast guy line anchors in the ground around the well site, the design and construction of these anchors **shall** comply with the original equipment manufacturer's (OEM's) documentation.

3.4.5 Compliance

Well sites and associated works **shall** be built and operated to comply with requirements of the applicable environmental consents and permits of the country where the work takes place as well as all applicable occupational health and safety statutes.

3.5 Cellar

3.5.1 Cellar function

A cellar **shall** be installed around the top of the proposed well. The function of the cellar is to address any or all of the following:

- (a) As a collection sump for drilling fluid returns until the first casing or conductor is run and cemented (unless a conductor pipe of adequate height to lift drilling returns to a level above the shale shakers is installed prior to drilling);
- (b) During casing cementing, to catch contaminated drilling fluids, cementing pre-flushes, contaminated, and excess cement slurries and route them to the waste sump;
- (c) To accommodate part of any drilling wellhead where the drilling rig does not have adequate space between the rotary table and ground level for the total wellhead and casing flanges; and
- (d) To provide a central collection point for local drainage during the drilling operation.

3.5.2 Cellar design, construction, and maintenance considerations

3.5.2.1

The cellar depth **should** be minimised and the cellar **shall** be well ventilated.

3.5.2.2

Cellars **shall** withstand all direct and indirect loads imposed by drilling equipment and operations and any subsequent installations.

NOTE

Cellars can be designed to incorporate permanent wellhead thrust frame anchor points.

3.5.2.3

Where cellars have the potential to trap poisonous gas, access **shall** be controlled. Typically, cellars of greater than 1 m in depth **shall** be managed as confined spaces. Cellars **shall** incorporate a fast

and easy means of exit from the cellar floor, both when the rig is operating and following rig removal. Ladders are not considered to be suitable as the sole means of exit from the cellar.

3.5.2.4

Permanent levelling datum(s) **should** be established on the cellar as reference points for measurement of changes in the height of the CHF relative to the cellar. The cellar datum **should** also be surveyed and included in the local benchmark network.

NOTE

- (1) In areas where significant ground subsidence becomes evident, maintaining a record of change in height of the CHF or the cellar benchmark over time could provide a useful indication of casing stress and the potential for resultant casing damage.
- (2) Environmental consent and permit conditions will usually require resurveys of the local benchmark network at regular intervals (usually in the range 4 – 6 years).

3.5.2.5

The cellar **shall** be drained:

- (a) By a pipe of not less than 250 mm inside diameter or an equivalent channel;
- (b) At a minimum grade of 1 in 40; and
- (c) With an invert at or slightly below cellar floor level.

NOTE

Smaller diameter pipes on flatter grades are likely to become blocked by cuttings, cement, mud, and debris and be rendered ineffective before drilling operations are completed.

3.6 Drainage and waste disposal

3.6.1 Consent compliance

Drainage from the site and disposal of wastes generated by the drilling and well testing operations **shall** comply with all relevant environmental consents and permits of the county where the work takes place.

3.6.2 Considerations in the design and use of waste sumps

Consider the following when designing and using waste sumps:

- (a) Waste sumps are constructed to contain cuttings and liquid drilling and cementing wastes and all other contaminated fluids generated by the drilling operations;

- (b) The sump is usually designed to allow isolation of part of the volume for primary settlement of solids, with any necessary secondary settlement and treatment occurring in the remaining volume. Alternatively, two separate sumps can be used;
- (c) Operating procedures **should** ensure that the maximum fluid level in the sump will remain below the cellar floor level;
- (d) The sump design and construction **should** ensure that there will be no erosion or collapse of the sump walls during operations;
- (e) Where two waste sumps are constructed close together, the design **shall** prevent leakage, erosion or collapse of the material separating the two sumps when the upstream sump is full and the downstream sump is empty;
- (f) The design of the upstream sump **should** allow for a holding capacity of at least five times the total volume of the solid material expected to be drilled from the well;
- (g) The volume necessary to contain all drilled solids, waste mud and cement will be determined by the following:
 - (i) Hole volumes – when brought to the surface, drill cuttings will occupy approximately twice the in-situ volume downhole
 - (ii) Formations to be drilled – erodible formations can result in over-gauge hole and excess cuttings;
- (h) Waste sump volume requirements can be reduced where:
 - (i) Cuttings are removed directly from the shale shaker
 - (ii) Solids-removal equipment with the drilling rig results in drilling wastes with a low water content and minimal mud waste;
- (i) Waste sumps **should** be periodically monitored in accordance with relevant environment consents and permits.

3.6.3 *Avoiding run-off into the cellar*

After well completion, the site **shall** be reshaped to preclude surface run-off entering the cellar.

3.7 Water supply

3.7.1 Adequate supply

An adequate supply of water **shall** be available to the site during all drilling operations. The supply rate **shall** be adequate for all quenching, drilling (including drilling without returns of circulation) and cementing operations. All applicable statues as well as rules and regulations related to water rights of the country in which the drilling takes place **shall** be adhered to.

NOTE

When drilling the bottom 8.5 inch diameter section of a typical 2000 m well, a water supply with a delivery capacity of at least 2000 litres per minute is required. Consideration should also be given to the security and redundancy of water supply lines.

3.7.2 Redundancy and backup equipment

Where two pump sets are to be used, they **shall** have independent power sources (for example, two diesel-powered, or one diesel and one electrically-powered, or two electrically-powered with a standby diesel-powered generator).

3.7.3 Water storage where there is no pump backup

Where only one water supply pump is available, then additional water storage and any necessary piping **shall** be installed to:

- (a) Feed water to the rig site by gravity;
- (b) Do so at a rate adequate to quench and control the well; and
- (c) Have a capacity that allows continuous quenching of the well for a period of not less than 12 hours.

NOTE

Typically, 800 – 1000 litres per minute would be required for quenching.

3.8 Multi-well sites

3.8.1 Cellar configuration on multi-well sites

On multi-well sites, wellhead and cellar locations and wellhead configuration, including any surface infrastructure, **shall** be designed and protected to allow for the installation and operation of a drilling rig over any well without endangering any other well on the same site.

NOTE

- (1) The spacing between wellheads will be determined by the clearances required between drilling equipment and the wellheads of completed wells, and by the ability to control the clearances from previously completed well tracks. Normally, the spacing would be not less than 5 m.
- (2) A multi-well site could use common waste sumps for all wells. To avoid the need for construction of excessively large waste sumps, provision can be made for either intercepting the solid wastes before they enter the waste sump, or removing the solid waste before commencing drilling operations on subsequent wells.

3.8.2 Exits from multi-well cellars

Where drilling a number of wells from a common cellar, a means of exit **shall** be provided between each wellhead.

3.9 Site security and signage

3.9.1 Security during drilling

Appropriate security **shall** be maintained to allow only authorised personnel access to the site during drilling operations.

3.9.2 Fencing and signage

Appropriate fencing and signage **shall** be erected and maintained.

Signage **shall** be located at the site entrance advising of:

- (a) Hazards, constraints on entry, and requirements for personal protection equipment;
- (b) Waste sumps that constitute hazards; and
- (c) Areas where hazardous gases are likely to be discharged or can accumulate.

All safety-related signage **shall** include recognized international safety and hazard symbols to ensure maximum safety for workers, local residents and visitors. Symbols for **Flammable, Crane Overhead, Danger of Suffocation, Watch for Falling Objects, Watch Your Step, High Voltage** and **Hard Hat Area** are among those highly suggested, along with any other signs deemed necessary.



Permanent signage **shall** be maintained in each cellar or on the wellhead stating the well identification name or number and the name and contact details of the well owner.

3.9.3 *Securing wellhead valves*

At all times the wellhead equipment **shall** be secured against operation by unauthorised personnel.

3.10 Well site records

The well owner **shall** maintain a permanent record showing the 'as-constructed' or 'as-built' details of the well site including:

- (a) Well location;
- (b) Cellar construction, including the location of any cellar drains;
- (c) Any other underground services or pipework;
- (d) Areas of cut and fill, undercut and ground improvement, including any consolidation grouting;
- (e) The locations of any drilling cuttings or other sumps, whether remaining in existence or removed; and
- (f) If drilling cuttings remain onsite, the location of those cuttings, and associated chemical analysis.

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4 DRILLING EQUIPMENT, TOOLS, AND MATERIALS

4.1 In this section

Section 4 covers the description of drilling equipment and tools, their inspection and maintenance, and the descriptions of the materials normally associated with the drilling and completion of a well.

4.1.1 – Rig and equipment hoisting capacity

On completion of the well design all loads to be imposed from drilling operations, including the running and cementing of casings, shall be assessed, and a margin of safety shall be added to establish the minimum hoisting capacity required.

The capacities of all components of the equipment specified and selected for the drilling shall exceed the minimum capacities estimated to be required to meet the loadings. Assessment of the capacities of separate components shall be undertaken.

4.1.2 – Drilling fluids and hydraulics programmes

In order to specify and select equipment, drilling fluids and hydraulics programmes shall be prepared for each well section. The programmes *should* consider at least the following aspects:

- (a) The types of drilling fluids used and their properties;
- (b) Minimum annular velocities necessary to ensure adequate removal of cuttings from the well;
- (c) Pressure losses through each component of the circulating system (for example, through the drill string, bit jets, annulus);
- (d) Differential pressures between the circulating fluids in the well and the fluid pressures in the formations;
- (e) Hydraulic horsepower requirements; and
- (f) Ability to cool and quench the well.

4.2 Equipment

4.2.1 – Suitability of equipment

Equipment associated with drilling works shall be assessed for suitability and wherever applicable, **should** comply with national, international, and API standards.

4.2.2 – Mast and substructure

The mast and substructures **should** be designed in accordance with API Spec 4F.

The mast shall have a load capacity in excess of the maximum hook load assessed in 4.1.1. This load capacity shall apply with both the zero pipe setback and the full mast setback capacity of drill pipe when subjected to the maximum wind speeds predicted for the proposed drilling location. The mast **shall** also have a capacity in excess of the drawwork's input power, drilling line strength, or hydraulic ram capacity, as applicable.

Both mast and substructures shall be inspected periodically for deterioration through fatigue, corrosion, overloading, or damage. Defective welds and bent, corroded or damaged members shall be repaired or replaced by competent tradesmen. All welding programmes shall be based on the materials used in the fabrication of the structures, and **shall** be subjected to pre- and post-heat treatment as necessary. Where structures cannot be repaired to their original condition, their safe working load rating **shall** be reduced accordingly. This revised rating **shall** not be exceeded in subsequent operations, and a notice **shall** be clearly displayed advising the reduced rating.

NOTE

The frequency of inspections will depend on previous drilling and storage history and, in particular, would occur immediately after any accidental damage or long period of storage. Masts and substructures are normally subjected to visual checks prior to commencing drilling operations.

4.2.3 – Travelling and hoisting equipment

Travelling and hoisting equipment **shall** be as follows:

- (a) The various items of hoisting equipment **shall** conform to the API Spec 8A and **shall** be inspected and maintained according to the API RP 8B;
- (b) Drilling line **shall** be in accordance with API Spec 9A and **should** be inspected and maintained in accordance with API RP 9B;

- (c) During operations the drilling line **shall** be visually inspected daily;
- (d) Where appropriate a ton-miles (or equivalent unit) record **should** be maintained for the drilling line, and a regular slipping and cutting procedure or replacement of the line **should** be used; and
- (e) For conventional drilling rigs, the drawworks **shall** be fitted with a safety device which prevents the travelling block being pulled up into the crown block.

4.2.4 – Rotary equipment

Rotary equipment includes the rotary, kelly drive bushing, kelly, and swivel.

The various items of rotary equipment **shall** conform to the API specifications, and **shall** be inspected and maintained according to the API recommended practice, as set out in Table 8:

Table 8
API specifications and recommended practice for rotary equipment

Item	API Spec	API RP
Rotary table	7K	–
Kelly drive bushing	7K	–
Kelly	7-1	–
Swivel	8C	8B

The swivel and kelly shall have a static load capacity in excess of the maximum hook load assessed in 4.1.1 (page 59). They **should** have a dynamic or rotating capacity in excess of the maximum hook loads likely during a normal drilling operation.

4.2.5 – Engines and drives

Chains and sprockets **should** conform to API Spec 7F.

The drive train **shall** be arranged so that mud pump operation can continue while the drill string is being tripped into or out of the hole.

4.2.6 – Generators, electrical system, and lighting

Generator capacity **shall** be adequate to supply the entire electrical load required by the rig and associated equipment to be used in drilling the well.

NOTE

- (1) It is not necessary for the equipment to meet the requirements for flameproofing normally required in oil and gas drilling operations.
- (2) Drilling operations in geothermal areas are likely to encounter abnormal hydrogen sulphide (H₂S) gas quantities, and consideration should be given to the deleterious effects of this gas on electrical and electronic components.

Items that could be on or with the rig and require an electric power supply include (but are not limited to) the following:

- (a) Prime movers driving the drawworks, pumps or rotary table;
- (b) Electrically driven air compressors;
- (c) Lighting;
- (d) BOP accumulator pump;
- (e) Mud agitators;
- (f) Deck winches;
- (g) Heating;
- (h) Fluid cooling facility (for example, cooling tower fan);
- (i) Fuel transfer and supplementary water supply pumps; and
- (j) Power requirements of workshop, offices, ablution, and accommodation facilities.

4.2.7 – Standby generator capacity

Standby generator capacity **shall** also be available and be adequate to supply, at a minimum, the electrical load for items (a) to (d) of 4.2.6.

4.2.8 – Lighting

Adequate lighting **shall** be provided in all working areas to ensure safe, unhindered operations at night.

4.2.9 – Compressors

Air supply pressures and flow rates **shall** be adequate for their end use. Where an air supply fulfils a number of requirements then the compressor capacity **shall** be sufficient to supply all needs concurrently while maintaining acceptable pressure (for example, use of an

air winch **should** not reduce the airline pressure below that required to operate air clutches).

Air compressors could be required for the following purposes:

- (a) Rig air supply to operate machinery controls (for example clutches, throttles);
- (b) Instrument operation or purging;
- (c) Workshop air;
- (d) Backup BOP accumulator pump;
- (e) Handling tools (for example air winches, pipe spinner, kelly spinner);
- (f) Pneumatic transfer of powdered materials (for example cement, bentonite); and
- (g) Aerated fluid drilling.

A backup air supply **shall** also be available on the rig and be sufficient for 4.2.9 (a) and (d).

In addition to inspections of air receivers or pressure vessels as required by other regulations, such equipment **shall** be regularly inspected visually. The equipment **shall** not be used if it appears to be physically damaged, unless it is re-inspected, repaired if necessary, and tested. Pressurised air vessels **shall** be protected from physical damage during other nearby operations.

NOTE

Compressed air can be dangerous, particularly when at high pressures (for example, exceeding 9.0 MPa when using aerated drilling fluids) or contained in large vessels (for example, bulk cement storage silos).

4.2.10 – Cementing equipment

4.2.10.1

This section covers:

- (a) Cement;
- (b) Cement additive mixing facilities;
- (c) Cement pumps
- (d) Cementing heads;
- (e) Cement and additive storage and transfer facilities;
- (f) Slurry pumps;
- (g) Slurry test facilities; and
- (h) Water storage and supply facilities.

4.2.10.2

Equipment **shall** be sized to store, mix, or pump downhole all pre-flushes, spacers and cement slurries required for the largest single cementing operation programmed for the well.

4.2.10.3

If the primary cement storage on site does not have adequate capacity for all stages of cementing of a particular casing (for example, first stage, second stage, backfilling), then provision **shall** be made to restock the primary storage. This **shall** be done within a time that does not adversely affect the completion of the casing cementing.

4.2.10.4

Cement and additive storage will be either bagged or bulk. Bulk storage is preferred for the primary cementing materials. Steps **shall** be taken to prevent rain and other environmental factors adversely affecting material quality. Bulk storage may be in gravity feed or in pressurised tanks or silos. Pressurised tanks and pressurised silos **shall** be designed as pressure vessels.

4.2.10.5

The whole of the equipment for the transfer of cement and additives **shall** be of sufficient capacity to accommodate the rates at which slurries will be mixed and pumped downhole. This **shall** include the materials handling and opening facilities for any bagged supply, and both the quantity and quality of the air supply required for any transfer systems involving pneumatic transfer or pneumatically-assisted transfer.

4.2.10.6

The mixing of water with cement and additives to form pumpable slurries **shall** be carried out using equipment that ensures complete mixing of the materials in proportions that satisfy slurry quality control requirements. There **should** be a holding tank (and bypass outlet or dump) of adequate volume between the mixing unit and the downhole pumping unit to enable corrective measures to be taken in the event that slurries do not meet specification. The holding tank **shall** be equipped with stirrers to provide for continuous stirring of slurry in the tank.

4.2.10.7

Sufficient water supply capacity **shall** exist, preferably duplicated or with adequate on-site storage, so that a failure of the water supply system or part thereof does not affect the cementing.

4.2.10.8

The preferred cementing method is a dedicated mixing and pumping system for placing slurry. If such a system is not available, positive displacement rig pumps may be used. For either system, 100% redundant capacity for pumping and pipe manifolding to the wellhead **shall** be available so that standby equipment can be quickly brought into service in the event of failure of the primary system.

4.2.10.9

The piping and manifolding system from the slurry pumps to the cementing wellhead shall allow rapid transfer from pumping downhole (by the casing or drill pipe) to pumping slurry or water down the annulus.

4.2.10.10

Minimum equipment for quality control of cement slurry shall be:

- (a) A mud balance; and
- (b) Facilities for taking and storing cement slurry samples.

4.2.11 – *Drilling fluid systems*

4.2.11.1

This section covers:

- (a) Mud tanks;
- (b) Pump suction and discharge piping;
- (c) Mud mixing and circulating equipment;
- (d) Air compressor discharge piping;
- (e) Fluid mixing and distribution manifolds;
- (f) Standpipe;
- (g) Rotary hose;
- (h) Mud return flow line;
- (i) Bloopie line;
- (j) Liquid-gas separators;
- (k) Shale shakers;
- (l) Desilters;
- (m) Desanders;
- (n) Fluid cooler; and
- (o) Associated equipment.

4.2.11.2

The pressure rating of high-pressure lines **shall** consider erosion, corrosion, and wear.

4.2.11.3

If aerated drilling is being utilised or if it is expected that hot geothermal fluids may be present in the return flows, then a blooie line **shall** be designed and installed. It shall be of adequate capacity with appropriate anchors, supports, and discharge control. The blooie line shall include at least one valve close to the wellhead. Both the valve(s) and connection to the wellhead **shall** be designed to contain the maximum likely service pressures. If a separator connected to the blooie line is capable of being pressurised, then the separator and the incoming blooie line **shall** be designed and sized as pressure vessels. Provision **shall** be made in the design for erosion from aerated returns.

4.2.11.4

When drilling, a fluid cooling system **shall** be installed into the surface fluid handling system. This **shall** be capable of maintaining mud at the primary pump suction at a temperature not exceeding 60°C under all drilling conditions.

NOTE

Elevated mud temperatures may adversely affect the properties of the mud and may cause boiling of the mud at or near the surface. Cooling may be achieved using evaporative cooling, assisted by forced draft cooling towers.

4.2.12 – Mud pumps

Mud pumps **should** be of a positive displacement type. They **shall** be specified so that they can maintain flow rates and pressures as determined in 4.1.2 (see page 59) without exceeding input horsepower, horsepower rating, fluid end pressure, or pump speed limitations.

The primary pumps used to circulate drilling fluids in the well **shall** have redundant capacity so that if one pump is inoperable then a standby pump has adequate capacity to control the well through the drill string.

Pumps **shall** be capable of pumping fluids at elevated temperatures (but not exceeding 85°C). Precharge pumps may be required to elevate the suction pressure of the primary pumps.

4.2.13 – Drilling wellheads

For wellheads used during drilling and removed when the well is completed and a permanent wellhead installed (that is, a drilling wellhead), the following apply (for permanent wellhead requirements, see 2.11 [page 41] and 5.11 [page 99]):

- (a) All components of the wellhead assembly which may be used to contain well or drilling operation pressures, **shall** be pressure rated for the Maximum Design Pressure for each hole section;
- (b) Valves and flanges **shall** comply with API Spec 6A and Spec 6D;
- (c) Drilling spools **shall** conform to API Spec 16A and API Spec 6A; and
- (d) All drill-through equipment **shall** conform to API Spec 16A.

NOTE

- (1) Drilling wellheads include some or all of the following components:
 - (a) Valves;
 - (b) BOPs;
 - (c) Flanges or clamped hubs;
 - (d) Spools, tees and crosses;
 - (e) Banjo Box; and
 - (f) Rotating head.
- (2) Spools need inspection for excessive erosion, particularly when aerated drilling-fluids are being used.

4.2.14 – Aerated drilling equipment

4.2.14.1

Surface air supply equipment used to aerate drilling fluids **shall** be fitted with pressure relief valves of adequate flow capacity to ensure that pressure ratings are not exceeded under any circumstances.

4.2.14.2

Non-return valves **should** be fitted to the air lines to prevent liquids entering the lines from the rig pumps, the drill string, or the well.

4.2.14.3

All flexible air lines **shall** have clamped chain or wire rope safety links across all end connections to limit movement of the air line if the flexible line fails.

4.2.14.4

Airline manifolding **should** allow bypassing of any excess air and blowdown of the kelly, kelly hose, and drill string or equivalent top drive equipment.

4.2.14.5

The drill string **shall** include a non-return valve (NRV) to prevent inflow of annular fluids or formation into the bottom of the drill string (for example, when aerated fluids are vented from the drill string). NRVs **should** also be used in the upper sections of the drill string to minimise the volume of aerated fluid to be vented from the drill string when making a connection. NRVs **should** use high temperature seals and seats, particularly when using aerated fluids because circulating temperatures are usually higher than when using mud or water.

4.2.14.6

When drilling with aerated fluids, the BOP stack **shall**, in addition to normal BOP requirements, include a rotating seal to control return fluids that could otherwise discharge to the working area, and a diverter to carry aerated return fluids in a controlled manner from the wellhead.

4.2.14.7

All discharge pipework used with aerated drilling **shall** have a pressure rating sufficient to withstand the maximum dynamic wellhead pressure (usually the same rating as the BOP stack), or have an upstream isolating valve, which is designed so that pipework (including any separators) downstream of the isolating valve is vented to the atmosphere, and is incapable of being closed off from the atmosphere.

4.2.15 – Blowout preventers and accumulators

4.2.15.1

BOP equipment and accumulators for those items of BOP equipment that are operated hydraulically, shall conform to API STD 53. BOPs shall be selected and installed according to 5.5 (see page 84). A typical wellhead and BOP stack for drilling with water or mud is shown in Figure 8 (see page 70).

NOTE

BOPs could be of the following types:

- (a) Gate (fitted with any of complete shut off or 'blind', pipe, casing or shear type rams);
- (b) Annular;
- (c) Rotating (used for pressure control rather than as preventers).
See API Spec 16RCD and API RP 64; and
- (d) Wireline (used when running instruments or tools on a wireline).

4.2.15.2

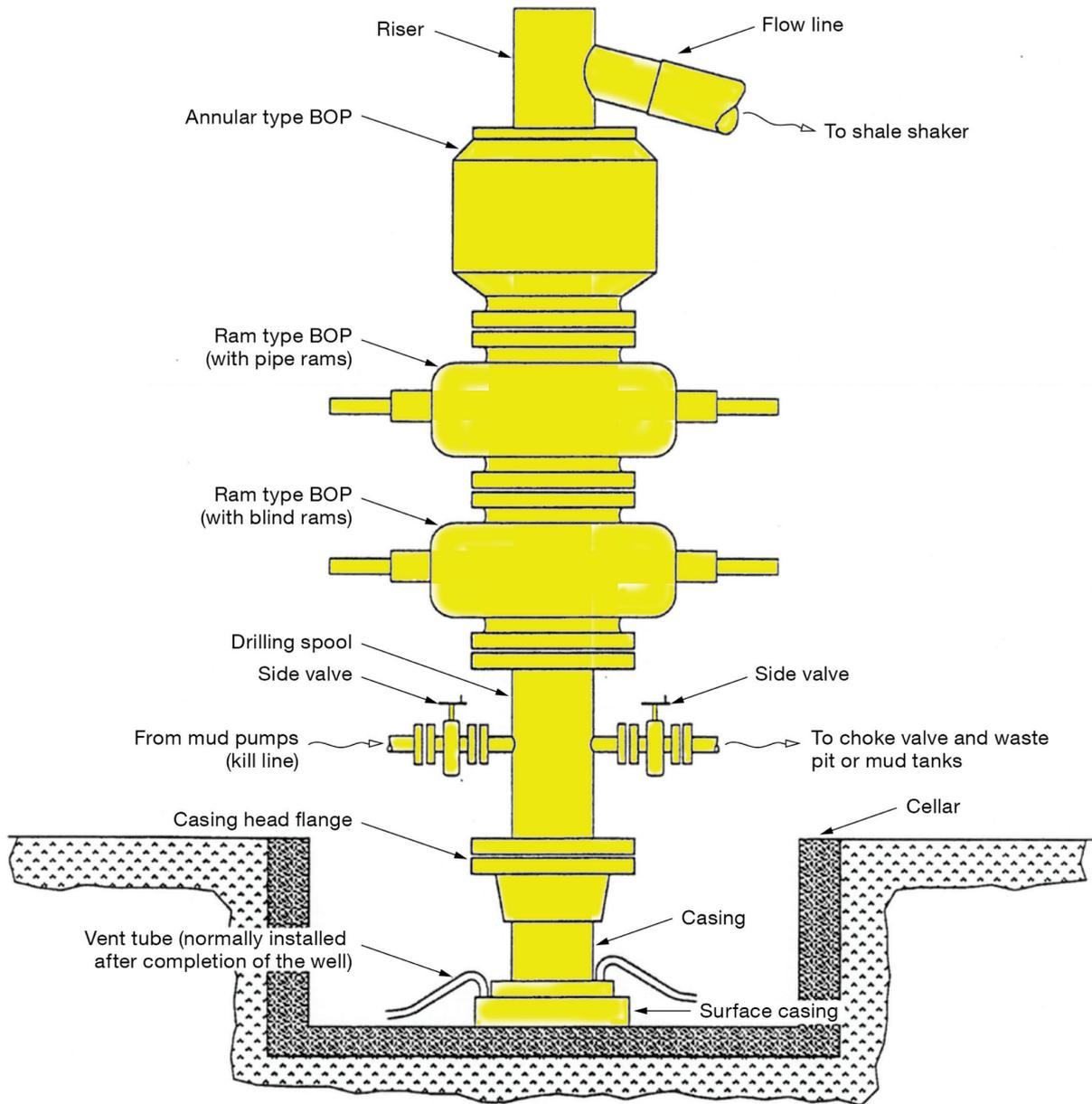
BOP equipment installed on a well **shall** be inspected, maintained, and function tested in accordance with API STD 53. Test pressures **shall** be not less than the maximum service conditions predicted by Section 2 (starting on page 11).

4.2.15.3

Operation of the BOP system **shall** be possible from at least two independent locations. One of these **shall** be adjacent to the driller's console and another **shall** be at a safe distance from the rig floor; a minimum of 10 to 20 meters from the wellhead/substructure and **shall** be sheltered from any possible action.

The accumulator location is one such possible position.

Figure 8
Typical drilling wellhead for use
while drilling with water or mud (non-aerated)



4.2.15.4

Elastomeric materials used in gate and annular type rams **should** be chosen to withstand the elevated temperatures and the quality of geothermal fluids likely to be encountered. Rotating type BOPs used during drilling and tripping in aerated fluid drilling operations **shall** use high temperature resistant elastomeric materials. The temperature rating of the seals **shall** be documented and drilling conditions managed to maintain wellhead temperatures below the seal temperature ratings.

4.2.15.5

Pumping units on accumulators **shall** be powered by a minimum of two independent power sources irrespective of proposed well depth but otherwise according to API STD 53.

4.2.15.6

Accumulator volumetric capacity **shall** be sized to allow for opening and shutting the annular preventer plus single closure of either pipe or blind rams but **shall** otherwise be sized according to API STD 53.

4.2.16 – Gas detection

An appropriate gas detector system comprising at least two sensors with the capability of detecting both H₂S and CO₂ **shall** be on site and functioning at all times while the rig is operating. Gas detectors **shall** be maintained in accordance with the manufacturer's OEM documentation, and **shall** activate both audible and visual alarms.

A gas hazard abatement plan **shall** be prepared and all rig crew and support personnel **shall** be familiar with its application.

Gas hazard escape equipment **shall** be provided at appropriate locations and available for use at all times when the rig is operational. All rig and support personnel **shall** be trained and competent in the use of emergency life support apparatus (ELSA) or equivalent escape equipment. At least one self-contained breathing apparatus (SCBA) **shall** be onsite, and at least two of the rig crew on every shift shall be trained and competent in its use.

4.2.17 – Rig instrumentation

Minimum requirements for rig instrumentation shall be:

- (a) Total weight indicator;
- (b) Tank volume and gain-loss indicators;
- (c) Standpipe pressure gauge;

- (d) Wellhead pressure gauge; and
- (e) Indicators for temperatures of rig pump suction fluids and returning fluids.

Other instrumentation **shall** include:

- (f) Pump speed indicators;
- (g) Rotary torque indicator;
- (h) Drilling fluid flow rate indicator (including air flow if appropriate) for downhole flow, return flow, or both;
- (i) Kelly height and rate of penetration indicators;
- (j) Drilling fluid density;
- (k) Recorders which record any or all of these parameters;
- (l) Rotary speed indicator; and
- (m) Makeup torque indicator.

Rig instrumentation **shall** be inspected, maintained and recalibrated as necessary at the start of each well, and at intervals specified in the OEM standards during drilling operations.

4.2.18 – Storage facilities

Storage facilities for hazardous substances used in the drilling operation **shall** protect them from the adverse effects of the local environment and **shall** ensure that they do not endanger rig personnel.

Fuel storage tanks **shall** be designed and located to minimise potential hazards and **shall** comply with relevant national and/or local/regional statutes and regulation.

4.3 Tools

4.3.1 – Drill pipe and drill collars

Drill pipe **shall** be manufactured and tested according to API Spec 5DP. Steel grades **should** be selected which will resist sulphide stress cracking (as covered in ANSI/NACE MR 0175/ISO 15156), but remain within the strength capacity required by the proposed drilling conditions.

If the drill pipe is internally coated to control corrosion then high temperature coating **should** be specified.

Drill collars and drill-stem subs **should** be manufactured and tested according to API Spec 7-1. Connection selection **should** be according to API RP 7G.

Drill string and casing tubulars **shall** be stored according to API RP 5C1. Pipe racks shall be designed, constructed and erected so that they do not deflect or settle significantly when fully loaded.

4.3.2 – Reamers, stabilisers and hole openers

Reamers, stabilisers and hole openers **shall** have the same connection as the drill collars with which they will be run, to minimise the number of crossovers in the drill string.

Near bit tools **should** have a box connection to suit the standard bit connection as listed in API Spec 7-2, and **should** be bored for the appropriately sized non-return valve.

Stabiliser and reamer components **should** be selected to withstand highly abrasive drilling conditions and **should** have additional hard facing to reduce excessive wear in any extremely abrasive formations.

4.3.3 – Drilling bits

Bits **should** be threaded to API Spec 7-2. They shall be selected according to the anticipated drilling conditions.

NOTE

- (1) Tricone bits are normally used for drilling. Where formations are known to have consistent properties, other bit types such as polycrystalline diamond compact (PCD) and hybrid matrix impregnated designs can perform significantly better than tricone bits.
- (2) Formations are often abrasive requiring additional protection of the bit against shirt tail wear and loss of gauge.
- (3) While sealed roller and sealed journal style bearings do give a longer bit life, bearing seal life is reduced at elevated temperatures. Bits are available with seals designed for higher temperature performance.
- (4) The elevated temperatures also cause expansion of bearing lubricants and unless there is provision for this expansion in the bit design then the lubricant can be extruded past the seals when running into a hot hole. When circulation starts, cooling and contraction of the lubricant can cause drilling fluids to be drawn into the bearings, resulting in reduced bearing life.

4.3.4 – Pipe handling tools

Hoisting tools **shall** be inspected and maintained according to API RP 8B.

Other pipe handling tools (for example, tongs, drill collar lifting subs) **shall** also be inspected and maintained in a safe and functional condition.

4.3.5 – Directional drilling and downhole measurement tools

Downhole instruments used to measure hole angle and direction or to collect data while drilling **should** be:

- (a) Rated for operation at appropriate elevated temperatures; or
- (b) Protected from limited periods of exposure to elevated temperatures (for example, by heat sinks, heat shields, or both).

The selecting of tools to be used for deflecting the hole direction **shall** consider the temperatures likely to be encountered.

NOTE

Positive displacement downhole mud motors that rely on an elastomeric stator for their operation do not always operate correctly at temperatures that are high enough to cause swelling of the elastomer. When available, high temperature stator elastomers offer longer downhole service.

4.3.6 – Fishing tools

Fishing tools incorporating elastomeric materials (for example, pack-off rubbers, seals) **should** be fitted with high temperature elastomers where available.

Fishing tools incorporating liquid oil-filled reservoirs (for example, containing hydraulic or lubricating oils) **should** use high temperature oils and **should** have provision for free expansion and contraction of the oil without applying undue pressure to any seals.

Where explosives are to be used downhole (for example string-shots, junk charges, perforating charges), the explosives, detonators, detonating cord, detonating system, and the wireline **shall** all be selected for the temperature and pressure conditions likely to be encountered. Explosives and associated items **shall** be stored according to local or national requirements and secured against entry by unauthorized personal.

NOTE

Mechanical or hydro-mechanical jars have been found to offer best performance under elevated temperature service.

4.4 Consumable materials

4.4.1 – Casing and accessories

Casings **shall** conform to API Spec 5CT or API Spec 5L.
Centralisers **shall** be complete with stop rings.

Casing accessories (for example shoe, float collar, stage cementing collar, hanger) **shall** be threaded and be of the same steel grade as the adjacent casing. If not of the same grade, then they **shall** be of a grade acceptable to the materials selection criteria and the predicted service conditions (both minimum and maximum) detailed in Section 2 (starting on page 11). Where the accessory is not threaded with the same thread as the casing, then the crossover connection **should** be as long as possible (up to the length of a joint of casing). It **should** also be of a material which satisfies the material selection criteria and strength requirements for the predicted service conditions detailed in Section 2.

4.4.2 – Cement and additives

4.4.2.1

Cement and cement blends used **shall** be of a quality that has predictable properties under all mixing, pumping, and predicted service conditions (including both low and high temperatures). They **should** be selected to withstand long-term exposure to geothermal fluids and temperatures.

NOTE

- (1) Cements from different manufacturers, while conforming to API specifications, do not always behave the same when used in geothermal conditions with blends and additives and at different temperatures.
- (2) The selected cement or cement blend should be capable of lasting the design life of the well under the expected subsurface environmental conditions (that is, pressure, temperature and fluid conditions).

4.4.2.2

Where a water supply of unknown water quality is to be used for cementing, laboratory testing shall be undertaken to establish the flowing, thickening, and strength characteristics of proposed cement slurries.

NOTE

- (1) Surface waters derived from heavily forested areas can contain sufficient dissolved organic materials to significantly retard the setting rate of the cement slurry.

- (2) Geothermal fluids are not always suitable for cement slurries.
- (3) Analysis of water for nitrate, pH, chloride, sulphate and dissolved silica is useful as these affect the hydration.

4.4.2.3

Retarders used for any cementing operation **shall** be selected after considering both the maximum and minimum likely circulating temperatures.

NOTE

Some retarders designed for high temperature use result in cement slurry that will not set for a very long time, unless a minimum temperature is exceeded. Conversely, low temperature retarders may be ineffective at high temperatures resulting in flash setting of the cement slurry before it is in place.

4.4.2.4

All additives **should** be functional under the range of service conditions possible for each cementing operation and each blend used. Their effect on slurry flowing, setting, and strength properties **should** be certified by the manufacturer or tested in a laboratory prior to use at the expected temperatures.

NOTE

Cement additives commonly used include:

- (a) Silica additives. While these are sometimes recommended to reduce the strength retrogression and porosity increase, which occurs in neat cement slurries, at elevated temperatures excessive amounts (for example, over 20% by weight of cement) is likely to incur deterioration of the cement in the presence of carbonating groundwaters;
- (b) Retarders;
- (c) Accelerators;
- (d) Friction reducers;
- (e) Fluid loss control agents. The requirement to cement the total length of each casing in reservoirs with pressures below cold hydrostatic pressures results in large differential pressures between a column of cement and formation fluids. This can result in annular bridging with high water loss cements;
- (f) Mica. This will not decompose under elevated temperatures whereas most organic loss circulation materials will; and
- (g) Slurry weight reducing agents. These products are used to produce low density cement slurries to reduce losses during cementing.

4.4.3 – Drilling fluid materials

Drilling fluid materials **shall** be selected to provide the required properties at the temperatures anticipated for the particular drilling interval.

NOTE

For drilling the near-surface hole where lower temperatures are expected, no special treatment is needed for water-based bentonitic fluids. As drilling progresses and temperatures increase, drilling fluids require chemical treatment to maintain the desired viscosity, gel strength, and water loss properties.

Barite or alternative weighting material shall be available to the well site to produce weighted fluids as required for kick control.

Drilling fluid materials **should** comply with API Spec 13A.

NOTE

The properties of drilling fluids using any of the wide variety of materials available, normally require laboratory testing to ensure satisfactory performance at elevated temperatures and pressures prior to use downhole (See API RP 13I). Locally available alternative materials can be acceptable.

4.4.4 – Composition and application of drilling fluids

Drilling fluids **should** be water-based, and may comprise some or all of:

- (a) Bentonitic clay;
- (b) Polymers; and
- (c) Chemicals to control the flowing and static properties.

Such drilling fluids are normally used down to the depth of the deepest cemented casing or liner. Thereafter, water is typically used.

NOTE

Bentonite-based fluids are not recommended for use while drilling the higher temperature openhole section below the production casing. If there are significant fluid losses to the formation in the production section, the bentonite could impair the well permeability when the well heats.

4.4.5 – Aeration materials

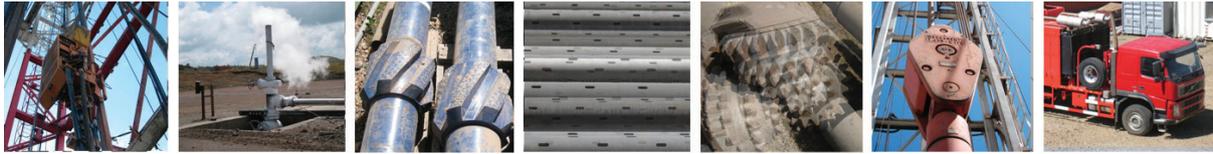
Materials used in aerated drilling fluids (for example foamers, defoamers, polymers, corrosion inhibitors) **shall** be selected to withstand elevated temperatures.

4.4.6 – Lost circulation material

Lost circulation material (LCM) to be pumped into the well **should** have a maximum size that does not adversely affect pump valve performance.

LCM used in casing cementation **should** not deteriorate at elevated temperatures.

Where cement plugs are used to seal zones of lost circulation during drilling, the cement slurry **shall** be formulated to produce a soft cement when set, to avoid kicking the well off into a new hole when attempting to drill out cement. When placed in a hot hole, the cement slurry **should** be retarded to ensure safe retrieval of the drill string.



5 DRILLING AND WELL TESTING PRACTICES

5.1 In this section

Section 5 covers the various activities involved in rotary drilling, completing, testing, and maintaining a well. Health and safety requirements during drilling operations **shall** be covered by the well owner's or construction contractor's safety management systems, or both in compliance with occupational health and safety statutes of the country where the drilling activity takes place.

NOTE

- (1) Geothermal drilling differs from conventional oil, gas, and water well drilling in the following principal areas:
 - (a) Temperature. Elevated reservoir temperatures reduce drilling bit performance, adversely affect drilling fluid and cementing slurry properties, reduce the performance of BOP components, increase corrosion rates and, in some reservoirs, provide a condition where loss of downhole pressure can result in reservoir liquid flashing to steam, resulting in a flowback or blowout from shallow depths;
 - (b) Geology. Many reservoirs are hosted in interlayered volcanic or sedimentary rocks, or both, and are commonly associated with local and regional faulting. As a consequence, highly permeable features are common and these can be implicated in depth intervals coincident with major losses of circulation. Shallow volcanics generally have low bulk densities and offer low resistance to blowouts; and
 - (c) Geochemistry. Geothermal fluids contain varying concentrations of dissolved solids and gases. These dissolved components can provide acidic or other corrosive fluids, and may induce scaling during well operations. Dissolved gases are normally dominated by CO₂ but also contain significant quantities of H₂S, both of which can provide a high risk to personnel and induce failure in both drilling tools and permanent well materials;
- (2) This code covers rotary drilling. Other drilling techniques include cable tool drilling, percussion drilling (utilising a downhole hammer) and jetting. Normally, they would be used only for relatively shallow drilling of hard rock or uncemented, unconsolidated formations, and consequently are not covered in detail in this code.
- (3) Wireline coring is not covered in detail in this code. But drilling practices described for conventional rotary drilling have general application to wireline coring operations. A conventional wireline coring operation adapted for geothermal drilling requires provision for the safe recovery of the inner barrel, and the use of a drill string without a non-return valve.

5.2 Competence and supervision of personnel

Personnel in immediate control of any drilling or workover operations **shall** be trained and competent in blowout prevention and control of geothermal wells, and one such person **shall** be directly in control of the rig while it is operational.

5.3 Drilling fluids and hydraulics

5.3.1 – Drilling fluids and hydraulics programme

The drilling fluids and hydraulics programme prepared in accordance with 4.1.2 (see page 59) **shall** be implemented and modified to suit the conditions encountered as drilling progresses.

NOTE

- (1) Drilling fluids are required to:
 - (a) Remove cuttings and formation gas from the well during drilling;
 - (b) Cool and lubricate the bit and drill string;
 - (c) Apply pressure to formation fluids for controlling flow into or out of the well; and
 - (d) Cool the formation, particularly prior to cementing.
- (2) Various drilling fluids are selected according to reservoir pressures and temperatures and the planned drilling techniques. Drilling fluids normally used include water, water-based bentonitic or polymer muds, aerated water or mud, stiff foam, mist, or air.
- (3) Oil-based drilling muds used in the oil and gas industry are not normally used in geothermal drilling.

5.3.2 – Monitoring the properties of drilling fluids

Fluid properties including density, viscosity, gel strength, water loss, and solids content **shall** be regularly measured and controlled.

NOTE

- (1) Static fluid pressures in geothermal reservoirs are normally less than those exerted by a column of cold water. Keep drilling fluid densities to a minimum to reduce losses, compatible with the requirements to control the inflow of formation fluids, and to ensure adequate hole cleaning. While mud specific gravity (SG) of 1.15 to 1.20 would be adequate in most reservoirs, an SG of over 1.9 could be required for short-term kick control.

- (2) For bentonite-based drilling fluids, elevated temperatures will normally cause significant increases in viscosity, gel strength, and fluid loss, particularly when circulation stops. With possible viscosity increase occurring downhole, viscosities measured at the surface could be lower than would otherwise be used in a cold well. High viscosities will increase pumping pressures and bottomhole circulating pressures, and will reduce the effectiveness of drilled solids' removal equipment at the surface. Marsh funnel viscosities would typically vary from 40 seconds in the cooler, upper hole to 35 – 38 seconds for deeper, hotter drilling.
- (3) Excessive gel strengths can cause high bottomhole pressures and losses of drilling fluids when circulation is restarted, and can result in high surge or swab pressures when running tubulars into or out of the hole. Gel strengths of 4.8 Pa (10 lbf/100 sq ft) would be typical for drilling at elevated temperatures. Excessive gel strengths can develop rapidly in stationary fluids at elevated temperatures.
- (4) Water loss from the fluid to the formation encourages the formation of a layer of thick mud or 'wall cake' as a lining in the hole. The wall cake assists the hydrostatic pressure from the drilling fluid to exert a stabilising pressure on the formation. But excessive water loss can build an undesirably thick wall cake in the hole, resulting in sticking of the drill string or casing in the hole. High temperatures tend to increase water loss and hence wall cake thickness. Water loss would normally be kept below 10 ml (cc)/30 minutes. Mud properties at higher temperatures can be deduced by measuring the high temperature fluid loss using standard API HTHP (high temperature/high pressure) test equipment (API RP 13B-1).

5.3.3 – Monitoring fluid volumes

The total volume of the drilling fluid, and the flow rate, temperature, and contents of any returns **shall** be monitored closely to provide earliest warning of an uncontrolled flowback of fluids from the reservoir.

NOTE

- (1) The following could indicate a potential flow of formation fluids into the well:
 - (a) A significant gain or loss of total volume which cannot be accounted for (for example, surface losses or aeration);
 - (b) A total loss of returns;
 - (c) A rapid increase in heat returned to the surface; or
 - (d) Formation gas in the returns,
- (2) The fluids may contain any mix of gas, steam or hot water and without proper BOP control may initiate an eruption of fluid from the well. See 5.5 on page 84.

5.3.4 – Circulation of drilling fluids

Drilling fluids **should** be circulated at a rate sufficient to lift cuttings from the bottom of the hole, and to cool the hole.

5.3.5 – Cooling drilling fluids

When return temperatures are hot, the returned fluids **shall** be cooled before recirculation to reduce deterioration of the fluid properties and to avoid boiling at the surface or in the well.

5.3.6 – Use of water as a sole drilling fluid

The use of water as a sole drilling fluid in sections other than the final open hole section **should** be avoided.

Where water is to be used as a drilling fluid, consideration **should** be given to pumping regular high viscosity sweeps to aid hole cleaning.

NOTE

- (1) The use of water will cause less damage to formation permeability than drilling muds.
- (2) Since water has a lower viscosity than drilling muds, the slip velocity of cuttings will be greater with water, requiring higher annular velocities to achieve adequate hole cleaning.
- (3) Annular velocities of at least 40 m per minute are used when drilling with water.
- (4) While drilling with water, whether with any returns to the surface or not, there is an increased risk of cuttings accumulating in various locations in the annulus. This is due to reduced velocity (for example, in areas of enlarged annulus such as adjacent to areas of enlarged hole, reduction in drill string diameter or increase in casing size). At low annular velocities cuttings will sink down the annulus resulting in stuck drill string.
- (5) The effects of accumulated cuttings are normally checked by regularly observing the depth of fill measured with the drill string without circulation or rotation, and by observing the drag and overpull when lifting or lowering the drill string.
- (6) Occasional mud sweeps may be necessary to retain the hole in a safe, drillable condition. While drilling the section of the well intended for production, minimising the volume and frequency of mud sweeps consistent with safe drilling, will reduce potential sealing of the natural permeability.
- (7) When drilling with water and with partial or no returns of drilling fluid, and if the water supply rate is limited, then continue drilling only as long as an adequate circulation rate can be maintained to achieve hole cleaning. If the water supply is inadequate, it is advisable to cease drilling and pull back to the casing shoe while the water storage is built up.
- (8) When drilling with water but without returns to the surface ('blind drilling'), a steady flow of water pumped down the annulus outside the drill string will help flush cuttings from the annulus. It will assist with both lubricating the upper drill string and cooling the shallower permeable zones (which will often be producing hot formation fluids into the well).

5.4 Drill string practice

5.4.1 – Drill string specifications

The following specifications apply:

- (a) The design, selection, and use of drill string components (for example, kelly, drill pipe, drill collars, core rods, downhole tools) **should** be according to API RP 7G or other recognised standard.
- (b) New drill string connections **should** be broken in by thorough cleaning, relubricating, slow make-up and application of appropriate torque for the style of connection as detailed in API RP 7G.
- (c) Thread lubricants recommended for use at elevated temperatures **should** be used for rotary-shouldered connections. Casing thread compounds **should** not be used on rotary-shouldered connections, see API RP 5A3.

5.4.2 – Monitoring make-up and break-out of connections

A calibrated tong torque gauge **should** be used to ensure that correct make-up torque is applied to drill string connections.

5.4.3 – Drill string inspections

Drill string components **shall** be inspected at regular intervals for wear, corrosion, cracking, pitting, and any other damage. Reamers, stabilisers and hole openers **shall** also be checked for cracking of body, blades and arms as appropriate. The intervals between inspections **should** be determined according to previous drilling and storage history of these components.

5.4.4 – Restriction of running speeds when tripping

Running speeds of drill string, both into and out of the well, **should** be restricted to a speed that does not:

- (a) Cause surge pressures sufficient to induce fluid losses to the formation; or
- (b) Cause swabbing pressures sufficient to induce inflow of formation fluids to the wellbore.

NOTE

A reduction in the pressure of high temperature water can induce boiling and flowback of fluids.

5.4.5 – Non-return valve

All drill strings run into a well **shall** contain a non-return valve in the lower end of the drill string.

5.4.6 – Cooling downhole tools when tripping

Depending on expected formation temperatures, cool fluids **shall** be circulated through the drill string at predetermined intervals while tripping. This is to avoid damage to any temperature-sensitive components such as jars, mud motors, electronic equipment, and drilling bits.

5.5 Well control

5.5.1 – When BOPs are required

A drilling wellhead (incorporating BOPs) **shall** be installed for all phases of drilling following cementation of the first string of casing, except:

- (a) Where reservoir fluids are excluded from the well by a cement or mechanical plug or packer inside cemented casing; and
- (b) Where it has been demonstrated that the well can be safely maintained in a quenched, non-discharging condition by pumping water into the well.

5.5.2 – Means of attaching drilling wellhead

The drilling wellhead **shall** be attached to the deepest cemented casing that extends to the surface, except where a shallower, larger diameter casing satisfies the design requirements of section 2 and the integrity of the cement between the shallower and deeper casings is adequate for the predicted service conditions.

5.5.3 – Provision for BOPs to shut off the well

The drilling wellhead **shall** have provision for complete shut-off of the well both with and without drilling tubulars in the well, together with provisions to control fluid flow from the well (that is, choke line) and to inject fluids into the well (that is, kill line). Both the kill and choke lines **shall** be below the points of shut off.

5.5.4 – Minimum drilling wellhead requirements

Minimum drilling wellhead requirements are a valve or ram type BOP fitted with complete shut off rams and an annular type BOP with kill and choke lines attached to the lower part of the lower BOP or to a drilling spool between the BOP and casing.

NOTE

It is normal to include some backup capacity by also having a ram type BOP fitted with drill pipe rams. A drilling valve may also be incorporated.

5.5.5 – Master valve installation

The timing of the installation of the master valve **should** consider these factors:

- (a) The susceptibility of valves to damage from tools run through the valve and to an accumulation of drilled and drilling solids and cement. Exposure to such conditions can cause the valve to malfunction.
- (b) The relative safety of installing the master valve at the completion of the well, considering the time required and risks inherent with lifting and removing the BOP stack and replacing it with the master valve and the time the wellbore is exposed with no primary isolation.
- (c) Any potential protection measures available to protect the permanent master valve if drilled through – for example, using a sleeve or flange with a smaller diameter.

5.5.6 – Underbalanced drilling

Where it is proposed to drill with a positive annulus pressure at the wellhead (for example, when drilling with aerated fluids or other underbalanced condition), a rotating blowout preventer and diverter **shall** be included in the drilling wellhead.

5.5.7 – Testing and inspection of BOPs

Requirements for inspection and testing of the wellhead equipment are:

- (a) Drilling wellheads **shall** be pressure tested after assembly and prior to drilling out cement from the casing.
- (b) BOPs **shall** be regularly inspected, function tested and maintained in accordance with API STD 53 (see 4.2.15.2 on page 69).

5.5.8 – Avoiding flowback or discharge of the well

Drilling practices that avoid initiating a flowback or discharge of the well **should** be adopted. These include:

- (a) Filling the drill pipe before attaching a circulating head or kelly and re-establishing circulation;
- (b) Pulling drill pipe from the well at a speed which does not induce swabbing of fluid from the well or reduction of downhole pressures to less than static formation fluid pressures;
- (c) Filling the well with liquid when pulling the drill string from the well;

- (d) Cooling the drilling fluid adequately prior to circulating down the drill string;
- (e) Pumping at an adequate rate to cool the well;
- (f) Refraining from pumping a drilling fluid containing entrained air or gas;
- (g) Using a drilling fluid with adequate density to give downhole pressures in the hole which are more than reservoir fluid pressures at the same depth (that is, drilling in an overbalanced condition);
- (h) Leaving the hole or part thereof filled with a fluid which has sufficient density and gel strength to avoid becoming gas cut over a period of time (for example, pilot holes during the period required to open the full length of the pilot hole to the desired diameter);
- (i) Reducing the rate of penetration to allow gas or heat to be circulated out when drilling through softer formations which may contain gas or high temperature fluids;
- (j) Pumping water to the annulus outside the drill string when drilling without fluid returns; and
- (k) Circulating drilling fluid in stages when running drill string into a hot well to remove heat from the well.

5.5.9 – Maintaining well control through continual monitoring of drilling parameters

Relevant drilling parameters **shall** be monitored continually. Some indications that the well may start or has started to flow back include:

- (a) Changes in the total volume of drilling fluid;
- (b) Signs of formation gas in the drilling fluid returns;
- (c) Increase in the temperature of the drilling fluid returns;
- (d) Increase in the flow rate of the drilling fluid returns;
- (e) A rapid increase in penetration rate or a drilling break (where the hole is advanced rapidly with little or no weight being required on the bit);
- (f) A loss of circulation;
- (g) An apparent loss of drill string weight while drilling, which is inconsistent with the rate of feed of drill string into the well; and
- (h) Contamination of the drilling fluid as indicated by reduction in density or increase in dissolved solids (for example, NaCl).

NOTE

- (1) When drilling without returns, a deeper loss of circulation may be indicated by a rapid loss of pumping pressure.
- (2) An influx of hot fluids into the well will cause the drill string to expand resulting in an increase in the weight on the bit.

5.5.10 – Well control procedures

Well control procedures **shall** be implemented at the first indication that a flowback may be possible or is occurring.

NOTE

Well control could include the following steps:

- (a) If there is drill string on the bottom, pull off the bottom to avoid becoming stuck;
- (b) Check whether the choke line is open or closed, depending on the preference for a soft or hard shut-in, and close an appropriate BOP (that is, blind rams if there is no drill string in the well, pipe rams if opposite drill pipe, or annular preventer if neither of the foregoing apply). Close the choke, if it is not already closed, and measure the drill pipe and annulus pressures. Determine if quenching the well will be tried, which assumes the cause is a thermal kick with no gas or pressure, by following (3), (4), and (8), or if the kick will be circulated out, following (e);
- (c) Pump drilling fluid to cool the well;
- (d) If a thermal kick is assumed and the flowback is actually from gas or an overpressured zone, conditions can deteriorate rapidly and result in loss of well control. The decision to assume it is a thermal kick that can be controlled using water needs constant review during the quenching process;
- (e) If the drill string is in the well, pumping down the drill string via the kelly or a circulating head is more effective than pumping to the annulus;
- (f) Control the wellhead pressure by gradually opening or closing the choke line maintaining sufficient pressure to prevent the returning fluids from boiling;
- (g) Fluids in a well (including drilling fluids) can be heated to temperatures significantly above 100°C. When the pressure on such hot fluids reduces, the water in the fluid will start boiling to steam. The steam will reduce the density of the fluid column in the well causing further reduction in downhole pressures and result in further boiling of water. Such boiling can be self-sustaining and accelerate until boiling occurs over most or all of the well depth. This phenomenon is distinctly different from the rising, expanding gas bubble considered as the basis for the kick control in oil and gas drilling BOP operating procedures; and
- (h) If there is any possibility that the flowback is from a gas zone or an over-pressured water zone, follow conventional methods of circulating out a kick.

5.5.11 – Managing hazardous gases

When hazardous gases are detected in the drilling fluid returns, all necessary safety actions **shall** be implemented to ensure that personnel are not at risk from the gases. In these circumstances, the bit **should** be pulled off the bottom, rotation continued, and the liquid flow rate (but not the air flow rate if aerated fluids are being used) increased. If necessary, the BOP **should** be closed and the well circulated back to the mud tanks through the choke line.

NOTE

Following initial actions to safeguard personnel and the well from the effects of hazardous gases, circulate the gas out of the well. If this is unsuccessful, control the rate of inflow of the gases by changing the circulating parameters if necessary. In extreme cases this could require drilling ahead without aeration of the drilling fluids, or instigating treatment of the returns to reduce ambient gas concentrations to acceptable levels.

5.6 Running casing

5.6.1 – Casing handling and storage

Casing **shall** be handled and stored as recommended in API RP 5C1.

NOTE

Because thermally induced stresses in casing often approach and sometimes exceed minimum specified yield stresses, the integrity of the string of casing relies on minimal or no physical or welding damage to the casing and its connections.

5.6.2 – Cleaning and inspecting casing threads

Except when cleaning and inspecting casing threads, the lower protectors **should** not be removed from a joint of casing until it has been pulled up into the mast. Prior to running threaded casing, thread protectors and handling-tight couplings **should** be removed, threads cleaned, visually inspected, relubricated, and the cleaned lower protectors screwed back on (or clamp on protectors).

5.6.3 – Drifting casing

Prior to running casing, the casing **should** be drifted on the racks using a drift dimensioned as prescribed in API Spec 5CT. Any casing joints that are bent, out of round, have damaged threads or are otherwise damaged **shall** be rejected and replaced by other joints of casing of the same grade and weight.

5.6.4 – Damaged casing

When the casing is run into the well, any casing joints that are bent, out of round, have damaged threads or are otherwise damaged **shall** be rejected and replaced by other joints of casing of the same grade and weight.

5.6.5 – Recording of casing tally

The length of all joints of casing and included accessories (for example shoe, float collar, stage cementers, hangers) **shall** be measured, recorded, and reconciled with the final casing tally run into the hole.

5.6.6 – Identification of casing differences

When casings of different grades, weights or connections are to be run, the different casings **shall** be positively identified, clearly marked, and laid out on the pipe racks in the programmed running order.

5.6.7 – Casing preparation and equipment

Prior to running any casing which is to be cemented into the well, all casing handling equipment and accessories, cementing materials, cementing accessories, measuring devices, and materials **shall** be on site and fully operational.

5.6.8 – Casing centralisers

Casing centralisers **should** be located by stop rings mechanically attached to the pipe body. Stop rings **shall** not be attached by welding to the casing. Casing centralisers **should** not be placed over couplings.

5.6.9 – Thread-locking

The bottom three joints of casing (including couplings if handling tight), casing shoes, floating equipment, and any other similar casing accessories located in the lower section of the casing string, **should** be made up with an epoxy or similar thread-locking lubricant. This is to avoid unscrewing of the accessory during subsequent drilling out and drilling operations. The thread-locking lubricant **shall** be formulated to perform satisfactorily at the anticipated elevated temperatures.

5.6.10 – Welding of casing

Where welding of or onto casing is unavoidable, a procedure appropriate to the materials and by welders qualified in that procedure **shall** be used. If H₂S might be present, welding **shall** conform to ANSI/NACE MR 0175/ISO 15156.

5.6.11 – Borehole preparation before running casing

Prior to running casing the hole **should** be free of ledges, dog-legs, and thick mud wall cake.

NOTE

- (1) Ledges or dog-legs can prevent running casing to the desired depth and induce unacceptable bending stresses in the casing.
- (2) The action of running the casing can result in cuttings or pieces of formation entering the well. An additional hole drilled below the planned casing shoe depth, usually about 3 m, can prevent such material filling the hole to a shallower depth than planned.
- (3) An additional hole also provides for thermal expansion of the casing.

5.6.12 – Fluid conditioning before running casing

Prior to pulling out the drill string in preparation for running casing into the hole, the hole **shall** be circulated until free of cuttings, the drilling fluid **should** be conditioned so that the fluid has minimal gel strength and minimal water loss, and cannot deteriorate significantly during the time required to pull out of the hole and run the casing. If a wiper trip is found to be necessary, do this immediately before running the casing.

NOTE

Running casing into drilling fluids with high gel strengths or high water loss or both can result in a loss of circulation, differential pressure sticking of the casing, or only partial removal of drilling fluids during any subsequent cementing operation.

5.6.13 – Casing running procedures

Casing **should** be run generally in accordance with API RP 5C1.

5.6.14 – Torque management for proprietary connections

Proprietary connections **shall** be torqued up following the manufacturer's recommended procedure. Torque **should** be adjusted according to the relative lubricity of the thread lubricant used on the casing (see 5.6.15).

5.6.15 – Thread dope

Thread dope **shall** comply with those prescribed in API RP 5A3 for casing. In API 5 A3 lubricants specified for rotary-shouldered connections are not necessarily suitable for use on casing threads.

NOTE

A number of companies manufacture casing thread lubricants. Different lubricants can have different lubricities. The lubricity or friction factor of various products can vary from 0.60 to 1.60 of that For API modified thread lubricant (API RP 5A3, Annex A). Unless specified otherwise by the casing thread manufacturer, recommended make-up torque assumes the use of 'API Modified' thread lubricant. Consequently, applied make-up torque is the recommended torque adjusted for the relative lubricity of the thread lubricant used.

5.6.16 – Making casing connections

When making up casing connections, a backup tong and a make-up tong (or power tong) **shall** be used. Using the casing slips in a locked rotary table instead of the backup tong **should** not be permitted.

5.6.17 – Control of casing running speed

Casing running speed **should** be controlled to avoid high bottomhole surge pressures and high acceleration loads. Where possible, such surge pressures **should** not exceed previous bottomhole circulating pressures.

NOTE

It is good practice to limit the total tensile load which may be applied while running casing (as shown on the weight indicator). If no restrictions are applied (see API RP 5C1), the total load can approach the lifting capacity of the drilling equipment.

5.6.18 – Avoidance of shock loadings

To avoid damage, casing running speed **shall** be reduced before inserting the slips.

NOTE

Severe shock loadings can be generated if the string is stopped suddenly, such as by lowering quickly into the slips. Such loadings are avoided by employing correct operating procedures.

5.6.19 – Maintaining fluid properties while running casing

With long strings of casing, running of the casing **should** be stopped at preselected intervals, the casing filled with drilling fluid, a circulating head installed, and the drilling fluid circulated through the casing to cool the well. During the period of circulation, the casing **should** be reciprocated to avoid differential sticking of the casing.

NOTE

The purposes of circulating the casing are to:

- (a) Replace annular fluid that can develop high gel strength under exposure to elevated temperature; and
- (b) Reduce the possibility of annular fluids reaching temperatures that can induce flash boiling of the annular fluid as it is displaced from the well.

5.6.20 – Controlling fluid temperature after running casing

When all casing has been run, the circulating or cementing head **shall** be installed and drilling fluid circulated. This is to minimise downhole temperatures before starting the cementing operation.

5.6.21 – Reciprocating casing

The casing **should** be kept in motion at all times (by reciprocation or rotation), except:

- (a) When it is necessary to have the casing stationary to install the cementing head, travelling plugs, or equipment required to operate downhole tools;
- (b) If the casing starts to become stuck; or
- (c) At the completion of the cementing.

5.7 Cementing casing

5.7.1 – Cementing programme

The cementing programme **shall** be designed and undertaken in a manner which is most likely to ensure that the total length of annulus outside the casing is completely filled with a good quality cement.

NOTE

If even relatively small volumes of cement slurry with excess water or small volumes of water are left entrapped by sound cement in the annulus between two casings, then subsequent heating and expansion of the water can induce collapse of the inner casing.

5.7.2 – Slurry volume allowances

Total slurry volumes **shall** include allowances for:

- (a) Displacement of contaminated slurries;
- (b) Over-gauge hole; and
- (c) Losses to the formation.

5.7.3 – Fluid conditioning before cementing

If the open hole has been exposed to or is filled with mud, then the primary cement slurries **shall** be preceded by fluids. The fluids **shall** be designed to maximise mud removal and minimise contamination of the primary cement.

NOTE

These fluids may include, but are not limited to:

- (a) Water spacers;
- (b) Chemical flushes to assist sealing loss zones or mud removal;
- (c) Dense mud spacers; and
- (d) A scavenging cement slurry with a high water content.

5.7.4 – Installation of cement delivery pipework

Cement delivery pipework **shall** be installed so that pumping of fluids to the annulus can be commenced immediately after the cement is displaced from inside the casing (that is, after the top travelling plug is in its final position). The cementing operation **shall** minimise the periods when the cement slurries are not in motion.

5.7.5 – Cement quality monitoring

Mixtures used for cementing **shall** be monitored and measured throughout the cementing operation to ensure that the concentrations of solids and additives are maintained as close as possible to design values.

NOTE

Quality control can be achieved by accurate premixing and monitoring of fluid densities, fluid viscosity and quantities of both wet and dry materials consumed at various stages of the cementing operation.

5.7.6 – Avoiding trapped water between casings

Additional primary cement **shall** be mixed and pumped to displace the high water content mixture from the well if:

- (a) A volume of primary cement containing excess water is pumped to the well; and
- (b) There is a possibility that the high water content mixture is likely to be displaced to a casing to casing annulus.

If sufficient materials are not available for this, then all cement **shall** be displaced from the well and the cementing operation started again. The nature of the returns from the annulus **shall** be continually monitored and correlated with the volumes pumped into the casing. This is so that the final location of any defective slurry can be calculated rapidly.

5.7.7 – Failure to place suitable cement between casings

If the fluid returns indicate that substandard material is likely to be in the casing to casing annulus at the time the cement slurry has been displaced from the casing, then the annulus **shall** be flushed with water from the top of the annulus to at least the shoe of the outer casing. This may require pressures sufficient to break down the formation below the outer casing shoe.

Care **shall** be taken not to exceed:

- (a) The collapse pressure of the inner casing;
- (b) The internal yield of the outer casing; and
- (c) The pressure rating of any lines or valves between the pump and wellhead.

5.7.8 – Backfill annulus cementing

The casing to casing annulus **shall** be recemented from the top of the annulus, using at least sufficient volume to fill the casing to casing annulus when:

- (a) 5.7.7 applies; or
- (b) The primary cement job does not reach the surface and so the casing to casing annulus has been flushed.

If the annulus does not fill up, then smaller volumes or batches of slurry **shall** be placed in the annulus. Leave an interval of time between each batch to allow previous cement to start setting (that is, ‘hesitation cementing’).

5.7.9 – Avoiding trapped water while backfilling

At no time after the commencement of backfilling with cement slurry **shall** water be allowed to enter the casing to casing annulus. If a volume of water or cement slurry with excess water enters the annulus then it **shall** be displaced as soon as possible from the annulus.

5.7.10 – Limitations to pressure applied to inside of casing or annulus

During any casing cementing operation, the pressure applied at surface **shall** be limited to prevent damage to the casings or wellhead from internal yield or casing collapse. This assessment **shall** be made over the entire length of the casing, and take into consideration materials properties, hydrostatic pressures both inside and outside of the casing, and any dynamic pressures introduced by fluid flow.

5.7.11 – Pressure test before drilling ahead

After completion of the cementing and erection of the next stage of the drilling wellhead and before drilling out cement from the casing, the wellhead **shall** be hydraulically pressure tested. Test pressures **shall** reflect the maximum service conditions anticipated during

all phases of drilling and completion relevant to that wellhead (see 4.2.13 on page 67). Test pressures **shall** be held for a minimum of 5 minutes and any leakage remedied. Casing and casing accessories **shall** be similarly tested above each accessory (for example liner lap, stage cementer, float collar, shoe). Should the pressure test indicate leakage from the casing, then the leakage point **shall** be cemented under pressure until an acceptable seal is achieved.

5.7.12 – Inadequate cement at the casing shoe

If the results from monitoring the cementing operation indicate that the cement around the shoe is inadequate then the shoe **shall** be squeeze cemented immediately after drilling the cement out of the casing.

NOTE

Assessment of the adequacy of cementing involves continual monitoring and recording of the returns and materials consumed during the course of every casing cementing operation. Correlation of such information with theoretical volumes of casing and annuli being filled provides information on the quality of the final casing cementation (for example, premature return of a fluid may indicate inadequate mud removal or collapsed hole; late returns may be caused by partial losses or over-gauge hole). The correlation is necessary to optimise remedial cementing operations and to assess the integrity of the final cementation.

5.7.13 – Removal of cement slurry from the cellar

All cement slurry (including contaminated slurry) discharged to the cellar or cellar drain **shall** be removed before the cement sets.

5.8 Lost circulation

5.8.1 – Minimising lost circulation

The following practices **should** be assessed and, where appropriate, employed to reduce likelihood of inducing losses of circulation while drilling:

- (a) Use drilling fluids which result in downhole pressures marginally above reservoir fluid pressures;
- (b) Control drill string tripping rates to avoid excessive swab and surge pressures; and
- (c) Maintain drilling fluid properties to avoid excessive build-up of wall cake and to ensure good hole cleaning.

5.8.2 – Curing losses

While drilling to the depth of the deepest cemented casing, reasonable attempts **should** be made to seal all loss zones as they are encountered. This is in order to ensure the best possible cementing of the casings.

NOTE

- (1) Partial losses may become sealed with mud during continued drilling, and may not require specific treatment beyond addition of LCM to the drilling fluid.
- (2) When a major or total loss of circulation is encountered, drilling some metres or tens of metres below the loss zone is more likely to ensure that the whole loss zone is covered prior to treatment.
- (3) Sealing of loss zones can be accomplished using LCM, gel (thick bentonite mixtures), or cement plugs. Alternative chemical sealing may also be effective. Plugs are normally given time to develop a gel or set strength before applying pressure to them (for example, before filling the well).

5.9 Directional drilling

5.9.1 – In this section

Section 5.9 covers drilling where the hole is intentionally drilled off-vertical using special tools towards a preselected target.

NOTE

Use of the following techniques and equipment may be necessary:

- (a) Survey methods to measure downhole inclination and direction of the hole so as to be able to calculate the hole position in three dimensions. Examples of survey methods include single-shot or multi-shot photographic surveys, mud-pulse or electromagnetically transmitted signals while drilling, and gyroscopic surveys;
- (b) Non-magnetic drill collars and, possibly, non-magnetic stabilisers, if magnetic type survey instruments are to be used;
- (c) Equipment to direct the drilling in the required direction and inclination and to correct the direction or inclination, as drilling progresses. Such equipment includes whipstocks, bent housing positive displacement or turbine-type mud motors, bent subs run above positive displacement, or turbine type mud motors and rotary steerable tools; and
- (d) Additional stabilisers, together with shorter, stiff drill collars.

5.9.2 – Selection of equipment

The selection of drilling equipment for directional drilling **shall** include consideration of additional capacity required to overcome drag from the inclined hole. Alternatively, the final well depth may require reduction to avoid exceeding available drilling equipment capacity.

5.9.3 – Kick-off point

The kick-off point, below which the hole is developed into an off-vertical hole, **should** be at least 50 m below the previous casing shoe.

5.9.4 – Drill string considerations

The drill string design, selection and use **should** take account of the limitations of API RP 7G for hole deviation. These limitations are not to be exceeded for the actual hole geometry and drilling environment.

5.9.5 – Avoiding damage to casing

Where the kick-off point is later cased off, care **should** be taken to avoid damage to the casing during subsequent drilling operations. This may include avoiding the rotation of hard-banded tool joints over intervals inside the casing where there is a change in hole angle or dog-leg, and pumping liquid down the annulus when drilling without returns of circulation. High temperature rubber protectors may be required on the drill pipe.

5.9.6 – Assessing damage to casing

On completion of the well, the casing condition **shall** be monitored for any damage, where:

- (a) The kick-off point and interval of hole where the hole angle is built up are inside casing; and
- (b) The section of hole below the casing subjects the casing to potential wear from subsequent drilling.

Any indicated casing damage **shall** be assessed. If it is likely to diminish the safety or integrity of the well then it **shall** be repaired.

5.9.7 – Directional surveys

Directional surveys **shall** be carried out over the complete wellbore length to accurately determine the well track.

NOTE

In both directional and straight holes, it is important to know the position of the well with reasonable accuracy. This is to ensure the correct wellbore path follows the planned trajectory and to know its position in the event a relief well must be drilled.

5.9.8 – Proximity of other wells

Drilling programmes for wells to be drilled from a multi-well site **shall** consider the proximity and status of other completed wells. If necessary, other wells may need to be closed or quenched during the drilling of critical sections of new wells.

NOTE

Intermediate casing shoe depths are normally selected to resist blowouts from the depth of the production casing. But if fluids from the openhole section of an adjacent, completed well can communicate with the hole for production casing in the well, then the previous casing seat can be subjected to higher pressures from the completed well. Without appropriate precautions (for example, quenching adjacent wells or modifying casing depths for the new well), a blowout can occur

5.10 Fishing

The following considerations apply to tools and tubulars used during fishing operations:

- (a) All tubulars and tools that are run into a well **shall** be measured, and all lengths and inside and outside diameters recorded, before running into the well;
- (b) All fishing tools and tubulars **shall** have a maximum outside diameter not exceeding the minimum drift diameter of the smallest casing through which the tool or tubulars will be run;
- (c) No drilling tools or tubulars **shall** be run into a well unless they have outside diameters or fishing neck diameters which provide adequate clearance between the tool and smallest casing or hole. This is to allow fishing of the tool or tubular using the fishing equipment which is available;
- (d) Allowance in depth calculations for thermal expansion and contraction of the fish and of the fishing string;
- (e) Thermal effects on fishing equipment; and
- (f) The operating limits of the drill-stem as covered by API RP 7G.

NOTE

- (1) Lead impression blocks can melt when exposed to the higher geothermal temperatures.
- (2) Hydraulic tools that rely on the viscosity of fluids in the tools are unlikely to operate satisfactorily at elevated temperatures if the fluid viscosity reduces significantly when heated.

- (3) Tools which rely on fluid containment or high differential pressures over flexible seals are unlikely to operate satisfactorily if elevated temperatures cause the seals to fail.
- (4) Fishing tools requiring lubricating or operating fluid to be contained in the tool require provision for expansion and contraction of the fluid as the tools are heated and cooled.
- (5) Electrical, electronic, and explosive equipment and materials used to locate and free lengths of stuck drill string have operational temperature limitations that require consideration when selecting materials and equipment. When running such materials and equipment into the well, reduce downhole temperatures as much as possible.

5.11 Well completion

5.11.1 – Baseline record for casing condition monitoring

Following well completion the inner cemented casing **shall** be logged. This is to confirm casing condition at the time of completion and to provide a baseline record for subsequent condition monitoring.

NOTE

For production wells and other high temperature wells this log is preferably performed before the casing becomes fully heated by putting the well on bleed or discharge.

5.11.2 – Running perforated liners

5.11.2.1

Prior to the perforated liner being run into the bottom of the well, the hole **should** be checked to ensure freedom from ledges or under-gauge hole. If necessary the hole **shall** be reamed from the previous casing shoe to the bottom of the hole.

5.11.2.2

When the hole has been drilled to the final depth:

- (a) Every effort **should** be made to wash all cuttings from the bottom of the well; and
- (b) The total length of the drill string in the hole at the time the bit is at hole bottom **shall** be checked to confirm the depth.

5.11.2.3

Before running the perforated liner, the potential for the well to kick or flowback during this operation **should** be assessed. Where there is potential for the well to come under pressure while running the perforated liner, there **shall** be provision to maintain or regain well control.

NOTE

- (1) Prior to running the liner, completely fill surface water and mud-tanks to provide the maximum quench water onsite in the event of a water-supply failure to site.
- (2) If there is any doubt about the ability to prevent the well flowing while running the perforated liner, check the well condition by running relevant downhole surveys to confirm downhole conditions while injecting cold water. If doubt still remains, then do a well response test should to determine how long the well will remain off pressure with a reduction or loss of water to the well.
- (3) If liner joints are perforated over the full length of each joint, closure of the BOP equipment across the perforated liner body will not provide reliable well control in the event of a well kick.
- (4) If liner joints are perforated over the lower half of each joint only, well control can be achieved by lowering the liner string to position an unperforated liner section through the BOP stack and sealing the top of the liner joint with the top drive or a suitable blank. This will allow the BOP equipment to be used for well control.
- (5) Keep a liner blank section (with the end sealed) on the rig floor, set up for rapid installation in the event of a loss of water or for any instances where the ability to shut-in the well during the running of the liner is required.
- (6) If there is inadequate time to install a joint of plain liner safely, consider and plan for dropping the liner down the well.

5.11.2.4

The time required to respond to a backflow condition **shall** be considered and minimised when running a perforated liner.

5.11.2.5

If a perforated liner is to be supported on hole bottom (that is, not hung) then sufficient liner **should** be run to extend from the final drilled depth (including any cored section at the well bottom) to a minimum of 16 m above the shoe of the previous cemented casing. The minimum casing length required **should** assume no thermal expansion and **should** allow for shortening through elastic helical buckling.

NOTE

Helical buckling is likely to be significant only where extensive lengths of over-gauge or under-reamed hole exist.

5.11.2.6

The perforated liner **shall** be run with an internally tapered guide on the top to facilitate easy entry of wireline instruments and drilling tools. The guide **should** have an outside diameter close to the drift diameter of the smallest casing through which the guide will be run.

5.11.2.7

If the perforated liner has been perforated in a manner that may leave obstructions protruding into or lying inside the liner, then such material **should** be removed either prior to running the casing or by scraping the liner after it has been run into the well.

5.11.3 – Installation of the permanent wellhead

5.11.3.1

Removal of the drilling wellhead and installation of the permanent wellhead **shall** be undertaken with the well in a fully controlled condition. If there is any possibility that, while pumping water into the well, it cannot be cooled enough to prevent backflow for the total time required to change the wellhead, then the well **shall** be plugged. This **shall** be done with a retrievable packer or drillable bridge plug or by a competent, pressure tested cement plug set inside the inner cemented casing.

5.11.3.2

All permanent wellhead components **shall** be pressure tested prior to installation on the well. Where possible, pre-assembled components **should** also be pressure tested as an assembled unit prior to installation.

NOTE

The CHF-casing connection (and CHF-master valve connection if the valve is installed at that time) will be tested when the BOP is attached to the anchor casing prior to drilling ahead (see 5.5.11 on page 88).

5.11.4 – Annulus corrosion protection

5.11.4.1

Where conditions warrant, a protection system **shall** be installed which prevents surface water entering the casing annuli and allows any gas that is migrating up the annuli to be vented away from the wellhead in a controlled manner (see also 2.11.4.3 on page 43).

NOTE

The purpose of the annulus protection system is to prevent rainwater entering the casing to casing annuli. Where rainwater is allowed to collect in the annulus between casings then geothermal gases flowing up the annulus, even at very low flow rates, can produce an acidic liquid which will corrode the casings and possibly expose the well to the risk of a wellhead failure.

5.11.4.2

The wellhead and exposed casings **shall** be sandblasted and painted with a high temperature paint system to afford maximum protection against corrosion.

5.11.5 – Maintaining drainage from the cellar

Following well completion and rig removal, drains from the cellar **shall** be cleaned and the site graded in a manner that ensures that water cannot accumulate in the cellar (see also 3.6.3 on page 54).

5.11.6 – Monitoring wellhead height

Following well completion and prior to allowing the well to heat up, the elevation of a fixed point on the wellhead (for example, the top of the CHF) **shall** be measured and recorded with reference to a permanent datum point installed on the cellar (see 3.5.2.4 on page 53).

5.11.7 – Rig release

The rig **shall** not be released until the well has been completed in a safe condition.

5.11.8 – Security of wellhead valves

Upon completion of works, the wellhead equipment **shall** be secured against operation by unauthorised personnel.

NOTE

This may be achieved by appropriate security or fencing, or by chains and locks.

5.11.9 – Specified operating range

Following well completion and before the well is put in service, the range of conditions under which the well can be safely operated **shall** be specified and documented. This specified operating range **shall** be reviewed throughout the lifetime of the well to ensure it reflects any changes in reservoir or well condition.

5.12 Well logging and testing

Downhole conditions **shall** be assessed by running downhole logs and tests. This assessment can be done during drilling, on well completion, and periodically throughout the life of a well.

5.12.1 – Types of well logs and tests

Well logs and tests carried out on geothermal wells can include any of the following:

- (a) Allowing or inducing the well to flow;
- (b) Downhole pressure-temperature-spinner surveys while pumping cold water into the well at one or more flow rates. The results of these measurements will indicate the depths to zones of fluid loss or gain and the relative flow rates into or out of those zones. The results may also indicate depths to an oversized or collapsed hole;
- (c) Pressure measurements taken at the depth of primary permeability while pumping water into the well at stepped, variable flow rates. Pressure changes with time as the flow is varied can be analysed to provide:
 - (i) Information on the average reservoir permeability
 - (ii) The well injectivity
 - (iii) Any near-hole anomalous permeability (for example, locally reduced permeability or ‘skin effect’ caused by mud damage);
- (d) Formation integrity of ‘Leak-off’ tests to assess formation integrity at a casing setting point;
- (e) Geophysical logs to map hydrothermal alteration and location of inferred fractures encountered in the wellbore;
- (f) Fluid sampling at the surface or downhole;
- (g) Sampling of cuttings returned to the surface via drilling fluids;
- (h) Examination and geological logging of cuttings collected during drilling and cutting of cores of formation, with their geological assessment of lithology, rank and intensity of hydrothermal alteration, fracture characteristics, and rock property testing (for example, density and porosity);
 - (i) Cutting cores while drilling;
 - (j) Running downhole logs to assess the placement of cement behind casing and the bond between the cement and casing;
 - (k) Down-hole cameras;
 - (l) ‘Go-devil’ runs wherein cylinders (drifts) of different diameters are run into a well on a wireline in order to measure internal clearance and identify the presence of blockages;

- (m) Spinner/fluid velocity profiles with or without fluid injection or discharge;
- (n) Mechanical calipers;
- (o) Logging tools utilising sonic or magnetic properties of the casing to assess the condition of casing and to identify areas of corrosion or erosion, any deformation in the casing or any failure of connections;
- (p) Logging tools utilising the sonic properties of rock to assess the productive formation;
- (q) Retrieval of downhole scale through scraping the casing;
- (r) Downhole video; or
- (s) Lead impression blocks to assess obstructions in the wellbore.

5.12.2 – Planning well logging and testing operations

5.12.2.1

The following **shall** be assessed with the same engineering rigour as other drilling activities:

- (a) Downhole and wellhead conditions anticipated during logging and testing activities;
- (b) The planned duration of those activities; and
- (c) Any changes to downhole conditions that could occur during that time.

NOTE

When used in fully heated geothermal wells slick wirelines are susceptible to embrittlement or corrosion in the saline geothermal fluids. Stainless steel slicklines are normally used for logging in a completed well. But bright or drawn-galvanised carbon steel well-measuring wire to API Spec 9A is normally satisfactory for use inside the drill pipe during drilling operations.

5.12.2.2

When logging or testing a well the following cautions **should** apply:

- (a) Where there is a possibility of the well coming under pressure while running downhole instruments, provision **shall** be made to control any flowback. If a lubricator or other wireline pressure control equipment is fitted to a tubular which is flanged to locate below the BOP rams, then neither the flange nor the tubular **shall** prevent complete closure of the well either by a wellhead valve or by the complete shut off BOP rams;

- (b) As flowing a well results in reduction of downhole pressures and erosive fluid velocities, the discharging of any uncased hole section can induce hole collapse;
- (c) Pressure measurements made in a well which contains mud or is providing only partial returns may not reflect formation fluid pressures;
- (d) Pressure measurements made in a well with a number of loss zones or with a controlling loss zone some distance above the bottom of the hole will probably reflect the formation pressure at the controlling loss zone only. The difference between pressures measured inside the hole and those existing in lower permeability intervals of the formation at the same depths can be large, particularly in reservoirs containing significant steam or gas;
- (e) Pressure measurements made inside the drill pipe may be of little value if there is an NRV in the drill string. Best results are obtained by using a flapper-type NRV, and pumping a small flow rate of fluid into the drill pipe to ensure that the valve remains open. Such measurements will reflect the pressure in the well at the bottom of the drill string only, and consequently pressure measurements taken at a number of different depths inside the drill string are not warranted;
- (f) Cooling of the hole from previous fluid circulation and loss of circulating fluid to the formation may affect the interpretation of temperature measurements;
- (g) Fluid samples taken from a well during drilling may be contaminated by drilling fluid or may consist entirely of drilling fluid;
- (h) All tools *should* be fishable;
- (i) Thermal effects on tools *should* be taken into account when selecting and running equipment;
- (j) Where appropriate, and particularly with wireline logs, data can be validated through comparable down and up logs; and
- (k) Depth calibration against well construction records, including, where applicable, provision for wireline expansion and stretch.

5.13 Drilling records

5.13.1 – *In this section*

Section 5.13 covers the acquisition and retention of data and other information gathered during drilling. It includes well logs or well testing carried out at the completion of the drilling process. The documentation and records required under each section of this code **shall** be permanently maintained and stored by the well owner and copies forwarded to the appropriate government Ministry, Agency, Department or Office responsible for the granting of geothermal drilling licenses or maintaining geological data.

5.13.2 – *Purpose of retaining drilling records*

Drilling records can be used for the following purposes:

- (a) As baseline input for subsequent well condition monitoring (see 6.3 on page 109);
- (b) For any well workover, intervention, or abandonment (see 6.5 [page 115], 6.6 [page 120] and Section 7 [page 123]);
- (c) As offset data to assist in the design and planning of subsequent wells;
- (d) To assist directional drillers to avoid collision by later wells and to ensure the well tracks are within legal boundaries;
- (e) To locate permeable zones and formation temperature and pressure conditions that can assist with the design of later well workover or abandonment, as well as for reservoir engineering purposes; and
- (f) To better understand geology and reservoir conditions.

5.13.3 – *Content of drilling records*

Table 9 describes the drilling and construction information that **shall** be recorded for each well, and permanently stored by the well owner and copies forwarded to the appropriate government Ministry, Agency, Department or Office responsible for the granting of geothermal drilling licenses or maintaining geological data.

Table 9
Content of drilling records

Information	Description
Well design	Complete well design documentation set out in 2.13 (see page 48)
Drilling programme	The steps and processes required to construct the well safely and in compliance with the well design (see 2.1.3 on page 11)
Design modifications	Any modifications to the well design or drilling programme made during construction
Daily drilling activity records	Daily drilling activity records including those components set out in 5.13.4 (see page 108)
Hole measurements	Depth and diameter of each hole size drilled
Casing specifications	The length, diameter, nominal weight or wall thickness, steel grade and connection-type of each string of casing run, including the length and coupling location of each joint of casing, and of all casing accessories (for example shoe, float collar, stage cementer, hanger, and crossovers)
Casing string depths	The final set depth of each string of casing
Cementing reports	Detailed reports of each casing cementation, including the quantities of materials used, the nature of returns to the surface, and any remedial cementing undertaken
Wellhead assembly	Details of the permanent wellhead assembly and cellar
Downhole survey data	Downhole survey data detailing depth, inclination, and azimuth of the well track
Unrecovered fish	Location and details of any fish not recovered from the well
Component failures	Any known or suspected failure in well components
Wellhead location	The surveyed location of the wellhead and the dimensional relationship between datum points in the cellar, drilling datum, and the permanent CHF
Lost circulation	Depths to and nature of any zones of lost circulation
Cores and cuttings	Details of cuttings and core samples retrieved from the well including geologist's description of formations penetrated. Such cores and cuttings <i>should</i> be adequately stored, marked, and recorded
Operating range	Specified operating range

5.13.4 – Daily drilling activity record

Table 10 describes the content of the daily drilling activity record that **shall** be maintained for each day of drilling or workover operations and copies forwarded to the appropriate government Ministry, Agency, Department or Office responsible for the granting of geothermal drilling licenses or maintaining geological data.

Table 10
Content of daily drilling activity record

Information	Description
Tool and drill string diameters	Length and inside and outside diameter of all tools and drill string run into the hole
Drilling bit details	Details of drilling bit diameter, make, type, serial number, jets, drilling time, drilled depth, and condition on recovery
Drilling depths	The depth drilled over specified time intervals throughout the reporting period depth
Consumables	Drilling consumables used, including the quantities, pumping pressures or flow rates, periods of use, rate of loss, and inflow and outflow temperatures, of drilling fluid
Drilling fluid properties	Drilling fluid properties (for example, density, viscosity, water loss, filter cake thickness, and gel strengths)
Drilling condition changes	Any material changes in drilling conditions including drilling breaks and obstructions or tight zones in the well, noting the times these events occur
Pressures	Standpipe and wellhead pressures
Drilling parameters	Ongoing measurement of drilling parameters (for example, weight on bit, rotary revolutions, both drill string and bit where they are different due to the use of a downhole motor drill string torque, pump rates, and all directional and other data captured through downhole sensors during operations)



6 WELL OPERATION AND MAINTENANCE

6.1 In this section

Section 6 covers the techniques and procedures to be adopted throughout the life of a well, following well completion. This includes operations pertaining to monitoring, inspecting, and repairing the well and wellhead components, and the discharging of the well. It does not include abandonment (see Section 7 starting on page 123).

6.2 Maintaining well integrity

Each well that has not been abandoned **shall** be operated and maintained to meet the objectives of this code, and be in general accordance with Section 2.

Any known deviation from the requirements of Section 2 (starting on page 11) **shall** require specific engineering assessment and an appropriate ongoing management plan.

When a potential defect is identified, additional monitoring or remedial work required to maintain the well condition **shall** be planned and carried out as soon as practicable, depending on the nature and the assessed risk resulting from that defect. Monitoring **shall** continue, at an appropriate frequency to allow for timely identification of any change in well condition, until the defect is remedied.

6.3 Well monitoring

6.3.1 – Well Monitoring Plan

A Well Monitoring Plan **shall** be established and maintained for both the downhole and surface components of all wells, taking into account:

- (a) The subsurface conditions;
- (b) The well operating range specified in accordance with 5.13.3 (see page 106);
- (c) Well history;
- (d) Changes observed in other wells in the field;

- (e) Ground subsidence;
- (f) Well configuration; and
- (g) Equipment availability.

The Well Monitoring Plan **shall** specify the inspection frequency for both downhole and surface components.

6.3.2 – Multiple Well Monitoring Plans

A Well Monitoring Plan can cover multiple wells or even reservoirs. Where this is the case:

- (a) The scope of the Well Monitoring Plan **shall** be stated, along with any individual wells or groups of wells that are specifically excluded from that plan; and copies forwarded to the appropriate government Ministry, Agency, Department or Office responsible for the granting of geothermal drilling licenses or maintaining geological data.
- (b) Processes **shall** be put in place to record any variation to the Well Monitoring Plan for individual wells or groups of wells.

6.3.3 – Identification of defects and impairments

The Well Monitoring Plan **shall** be designed to indicate the presence of any of the following defects or impairments:

- (a) External, near surface, corrosion or leakage of the anchor casing;
- (b) Any corrosion leakage of the wellhead components;
- (c) Broken or perforated casing;
- (d) Failed casing connections (for example, by pullout, compressive telescoping, or fracture);
- (e) Leaks into or out of the casing;
- (f) Buckled or distorted casing;
- (g) Collapsed casing;
- (h) Corroded casing;
- (i) Annular flow outside the casings; and
- (j) Chemical deposition or scale.

NOTE

Techniques and tools that can be used to indicate, identify, locate, or quantify defects or impairments below surface are listed in 5.12.1 (see page 103).

6.3.4 – Observation of change

The Well Monitoring Plan **shall** provide for observation of the following types of change, all of which can be observed at the surface:

- (a) Changes in discharged fluid chemistry, enthalpy, pressures or flow rates of production wells;
- (b) Changes in surface manifestations of geothermal flow, and particularly the development of new hot areas on or near the well site;
- (c) Any indication of fluids entering into a cemented casing annulus at surface and any deterioration of that cement near surface (such as may arise from rain water draining into a cellar);
- (d) Alternatively, any variation in flow from casing annuli; and
- (e) Loss of pressure measured at a side valve when the well is otherwise known to be under pressure.

6.3.5 – Wellhead inspection and maintenance

6.3.5.1

In addition to the Well Monitoring Plan, or alternatively, as part of it, each wellhead **shall** have a documented annual inspection, and at least the following information **shall** be recorded by the well owner and copies forwarded to the appropriate government Ministry, Agency, Department or Office responsible for the granting of geothermal drilling licenses or maintaining geological data.

- (a) Wellhead pressure;
- (b) Well Status (for example, shut-in, bleed, production, injection);
- (c) Operating condition of wellhead valves;
- (d) Leakage from valve gate or valve stem seals;
- (e) Condition of protective paint systems;
- (f) Condition of the anchor casing;
- (g) Condition of the site and cellar drainage; and
- (h) Changes in the vertical position of the wellhead measured relative to other casings and to the cellar and the position of the CHF measured relative to the cellar datum.

6.3.5.2

All steel surfaces of valve bodies, flanges, studs, nuts, spools, casing, and similar equipment, **shall** be maintained to be substantially free of corrosion.

6.3.5.3

Where protective paint systems require renewal, all defective painted areas **shall** be cleaned to bare steel before fresh coatings are applied.

6.3.5.4

Where severe external corrosion of the anchor casing is apparent or suspected, the casings outside the anchor casing **shall** be removed to a depth where sound casing is exposed, and the casing inspected.

6.3.5.5

Where the inspection identifies external corrosion of the anchor casing to an extent that the pressure rating is assessed as being inadequate for the particular well, then the casing **shall** be replaced as described in 6.5.4 (see page 119). Such modification **shall** be recorded as required by the well monitoring plan.

6.3.5.6

Where the inspection identifies external corrosion of the anchor casing to an extent that the pressure rating for that well is assessed as still being adequate for the particular well, then the corrosion **shall** be removed and the casing painted.

6.3.5.7

The casing annulus protection system **should** be maintained and be effective in venting the annuli while also preventing inflow of rainwater into the annuli.

6.3.5.8

Following any remedial work on the near-surface anchor casing, the outer casings and the casing annulus protection system (5.11.4, see page 101) **shall** be reinstated.

6.3.5.9

Any equipment, the failure of which could adversely affect the integrity of the well, **shall** be free of leakage and in sound operating condition. This includes all flanges, tappings, fittings, glands, valves and similar equipment.

NOTE

- (1) Deposition of dissolved solids can inhibit or prevent correct functioning of some equipment, particularly pressure relief valves.
- (2) Leaks past gate seats, valve stems, and flange seal rings can be stopped by operating the valve, injecting or replacing appropriate sealant or packing material, or uniform tightening of flange studs or bolts as appropriate. If such action is not successful then further measures described in 6.6 (see page 120) will be needed.
- (3) For wells that are not in use it is good practice to install a blank flange to protect the exposed face of the master valve and assist with elimination of scale associated with small leaks at the valve gate seats. With blank flanges use a small bleed valve to blowdown any pressure build-up.

6.3.6 – Risk assessment

A risk assessment **shall** be made for each well using the results of the monitoring and well inspections. This assessment **shall** be documented and periodically updated in accordance with the Well Monitoring Plan and copies forwarded to the appropriate government Ministry, Agency, Department or Office responsible for the granting of geothermal drilling licenses or maintaining geological data.

6.3.7 – Remedial works

Any remedial works identified by the inspection programme **shall** be completed as soon as practicable. Where there is a potential for further deterioration that threatens personnel safety, immediate steps **shall** be taken to eliminate that risk or to reduce the risk of harm to a level as low as is reasonably practicable

NOTE

In some cases it may be possible to temporarily make a well secure by reducing the internal pressure. This can be achieved by bleeding off high gas pressure or maintaining the well on production to reduce the wellhead pressure, until appropriate remedial works are made.

6.4 Wells in operation

6.4.1 – Master valve

6.4.1.1

The master valve **shall** remain operational and capable of being closed at all times.

6.4.1.2

Except in an emergency situation neither the master valve nor the side valves **shall** be used as flow control valves and in particular the master valve **shall** not be used to close a flowing well. If the primary

control valves do not seal fully then all other control valves which can reduce the flow rate **should** be closed as much as is possible before closing the primary valve.

6.4.2 – Minimising rapid temperature change

Wherever possible rapid temperature change of well casings, cement sheaths, and the wellhead **should** be avoided. Controlled heating and cooling (and where possible, limiting the number of thermal cycles) may mitigate the effects of temperature change on the casing and wellhead. For production wells this may be achieved by putting or keeping the well on bleed, by increasing any existing bleed rate, or by injecting hot fluids into the well.

NOTE

When the upper sections of a well are slowly heated, the potential for failure of well components induced by rapid opening of the well should be minimised. This is because, for example:

- (a) Slow heating of any water entrapped between casings can allow flow of the expanding water through any microannulus between the cement and casings, thus preventing a build-up of pressure to a level that can collapse the inner casings;
- (b) As the casings are heated, upward movement of the casing is restrained by the development of a force between the casings and formation. This force is developed by bond stresses between casing and cement, compressive stresses between casing couplings and cement, and shear stresses within the cement (and within the casing). Slow heating of the well allows more uniform heating of all casings and cement sheaths, thus providing more uniform distribution of the stresses between the inner casing and the formation. Conversely, rapid heating of the well will develop high stresses close to the inner casing, possibly exceeding the strength of the cement over some depth intervals. Localised failure of the cement can allow undesirable movement of the wellhead and concentration of thermally induced strain at weak points in the casing. This can result in failure of the casing.

6.4.3 – Bleeding a well

Bleeding of a well **should** be done from a side valve upstream of the master valve rather than downstream of the master valve.

Bleed line pipework **shall** be designed and installed to allow vertical movement of the wellhead and for thermal expansion and contraction, and **shall** be adequately anchored to prevent uncontrolled movement in the event of a failure from corrosion, erosion or other cause (particularly at bends and elbows).

Bleed lines **should** be terminated at some distance from the wellhead to avoid corrosion of the wellhead from discharged fluids and to avoid accumulation of hazardous gases within the cellar or other low-lying areas.

6.4.3.1

Any flow from the well **shall** have the flow rate controlled by a valve, orifice plate, or any appropriate device other than those valves comprising a part of the permanent wellhead assembly. This requirement applies to both low flow rates from bleeding of the well and any larger discharge rates from production of the well

Bleed lines **shall** be designed and installed in such a way to avoid creating a health or environmental hazard or a noise nuisance.

NOTE

Abatement measures needed to avoid environmental hazards could include chemical treatment upstream of the discharge, installation of sound absorbing apparatus at the point of discharge, or routing the discharge into a volume of water (for example, into the waste sump at the well site).

6.4.4 – *Hang-down tubing*

Where a hang-down tubing string is installed through the master valve and this could impede the closing of the master valve, consideration **shall** be given to providing a means of either quickly removing the tubing to allow the valve to be closed, or providing additional isolation (see 2.11.6.7 on page 47).

6.5 Workovers

6.5.1 – *Purpose of workovers*

This section covers operations on a completed well using a drilling rig or similar equipment (such as a coil tubing unit) to achieve any of the following:

- (a) Repair or replacement of a wellhead component (for example, master valve);
- (b) Repair or replacement of damaged casing;
- (c) Removal of scale deposits from the well;
- (d) Installation or removal of non-cemented liner from the well; and
- (e) Any other work inside the well required to modify the existing conditions in the well (for example, perforating casing, isolating permeable zones, deepening a well, or side tracking a well).

This section excludes those operations that can be carried out with the master valve remaining functional throughout the works, such as is typically the case for wireline work (for example, broaching).

6.5.1.1

Workover operations **shall** comply with all the requirements of Section 5 (starting on page 79) and, in particular, the requirements for monitoring and managing CO₂ and H₂S that may be released from the well (see 5.5.11 on page 88).

6.5.1.2

Prior to any workover, a programme **shall** be drawn up detailing the relevant information on the well, and the operations to be undertaken. The programme **shall** include appropriate methods of well control for the duration of the workover operations.

6.5.1.3

Where gas is bled from the well, the method of bleeding **shall** be managed to avoid creating a hazard to personnel or the local environment.

6.5.1.4

Most workovers will require the well to be controlled in a manner that prevents it from discharging. Where the type of workover permits, consideration **should** be given to plugging the wellbore using a retrievable packer located inside the wellhead or casing, rather than quenching using cold water.

6.5.1.5

A permanent record **shall** be made of all workover activities, incorporating those relevant well construction details specified in Sections 1.8 (see page 10) and 5.13.3 (see page 106).

6.5.2 – Quenching

6.5.2.1

When quenching a well with cold water, every effort **should** be made to avoid damage to the well casing by gradually cooling the wellbore in a controlled manner.

6.5.2.2

Initial flow rates *should* be controlled at a low level for a period of time and then gradually increased until the well is off-pressure. A typical quenching sequence is to commence pumping at not more than 25 litres per minute for the first hour of quenching, increasing at 25 litres per minute increments every 30 minutes until the well is off-pressure. Where large pumps are used for quenching, the low flows will require recirculating some of the output back to the pump suction.

6.5.2.3

A consequence of quenching a 'live' well is the production of non-condensable gas, which will accumulate in the upper part of the wellbore. During well quenching and workover operations it will often be necessary to vent the non-condensable gases in order to control the wellhead pressure.

NOTE

Portable blowers can be used to disperse high gas concentrations near the wellhead or in the cellar.

6.5.2.4

In most circumstances 'top quenching' is the most practical means of taking a well off pressure. Care *should* be taken as top quenching can result in the cold interface between the well fluids and injected fluids moving down the wellbore, resulting in rapid, localised cooling of the casing.

NOTE

Where casing is stressed, damaged, corroded, or has sections of substandard cementation, rapid cooling of the casing can initiate tensile failures. In this case, the preferred approach is to snub tubing into the well to the shoe of the production casing. Then the well can then be initially quenched by pumping cold water through the tubing, later switching to top quenching before removing the tubing. This results in more gradual cooling of hot fluids in the annulus outside the tubing, and rapid, localised cooling of the casing is avoided.

6.5.2.5

Any gas pressure that develops in the wellhead *should* be slowly reduced by bleeding the gas from the well both prior to and during the quenching operation in accordance with 6.5.2.3 (see page 45).

6.5.3 – Wellhead removal and replacement

6.5.3.1

Replacement of wellhead components (for example, master valves, side valves, seal rings, spools, and near-surface casing) may be undertaken using a retrievable packer set inside sound casing (or into an appropriately designed wellhead) to prevent the well flowing during the workover.

6.5.3.2

The general procedure to install a retrievable packer is:

- (a) Snub the packer into the well to the setting depth;
- (b) Set the packer; and
- (c) Where the design of the tool permits, take an upward pull to ensure that the packer is adequately anchored into the casing or wellhead.

The pressure above the packer **should** be bled off and the effectiveness of the packer seals confirmed before mechanically releasing the drill pipe from the packer or removing any wellhead component.

NOTE

If the well has been in production for any period of time, the **shallower** zones around the well will have been heated. In this case any water left above a packer set just below the wellhead could heat up with time and geyser out of the well, presenting a potential hazard when the wellhead equipment is removed.

6.5.3.3

Where a retrievable packer or other isolation is not used, the well **shall** be gradually quenched according to 6.5.2 (see page 116) and kept in a totally quenched condition for at least twice the estimated maintenance time required. After ensuring that the well will remain quenched, the replacement of components can then proceed.

6.5.3.4

When a well has been quenched and wellhead components removed, the well **shall** be kept in a fully quenched condition until it is secure. There **shall** be an adequate and secure water supply to the site to ensure that the well can be kept in a fully quenched condition for the maximum period that the well is likely to remain unsecured. If necessary, additional water storage or backup supply facilities **shall** be installed on site.

6.5.3.5

When the wellhead maintenance includes replacement of casing involving welding, any welding **shall** be in accordance with the welding procedures referred to in 2.11.5 (see page 45).

6.5.3.6

If the well has been quenched for the replacement of a section of casing involving welding, then the well **shall** be kept in a fully quenched condition in a manner that prevents cold water coming into contact with the casing being welded.

6.5.3.7

Care **shall** be taken during the cutting and removal of any section of casing to avoid damaging adjacent sections of casing.

6.5.3.8

If the wellhead maintenance results in damage to the annulus protection system (see 5.11.4 on page 101), then this **shall** be reinstated on completion of the works.

6.5.3.9

If the wellhead maintenance results in a change in elevation of the CHF, then the new height of the flange **shall** be surveyed and recorded on completion of the works.

6.5.4 – Downhole works

6.5.4.1

A drilling wellhead including BOPs **shall** be installed in any well that has potential to discharge during any phase of downhole works.

6.5.4.2

If the installation of new casing (scab liner) across a section of damaged or failed casing is planned, then the new casing **shall** be completely cemented over its full length. The scab liner and the well as re-completed **shall** comply with section 2. Prior to running the scab liner, a pressure test **shall** be carried out to determine if the damaged section of casing will accept water. If any significant leak is found, the loss points **shall** be located, any damaged casing aligned, and the loss points squeeze cemented prior to running the new casing. The wellbore below the scab liner **should** be isolated from any squeeze cementing, casing installation, and cementation operations.

NOTE

This may be achieved by setting a drillable plug or packer set inside the larger casing below the shoe of the new casing, or by using an external casing packer below a stage cementer in the new casing string.

6.5.4.3

When drilling scale in a permeable well, fluid returns and pump pressures **should** be continually monitored.

NOTE

When drilling scale from inside the casing, drilled scale can bridge and block the remaining hole through the scale below the bit. If this occurs then the flow of cooling fluids to the productive zones is prevented and can result in the well flowing back after a short period of time. When subsequent drilling passes any such blockage allowing the drilling fluid to travel downwards, cuttings above the bit can cause the drill string to become stuck.

6.6 Suspended wells

6.6.1 – Design of cement plugs for suspended wells

When a well is suspended, the following apply:

- (a) A cement plug or plugs **shall** be placed to provide not less than 100 m of continuous sound cement inside the production casing;
- (b) The cement plug **should** be placed on a bridge plug or packer located at or near the production casing shoe and not less than 10 m above the top of any liner;
- (c) The cement plug **should** also be placed in a manner that minimises dilution of the cement slurry by fluids in the well;
- (d) The cement materials **should** be selected to withstand ambient fluids and temperatures, and to develop a limited compressive strength to avoid casing damage when the cement is subsequently drilled out;
- (e) The casing above the sound cement **should** be filled to the surface with a weak bentonite and cement type of filler; and
- (f) The cement plug **shall** be pressure tested to a sufficient test pressure and duration to confirm the cement plug is sound and provides sufficient integrity for the duration of the well suspension.

NOTE

Depending on the purpose of the suspension, the cement plug may be placed higher in the casing to allow perforation or to achieve other objectives.

6.6.2 – Removal of the wellhead

Where a well is suspended in accordance with 6.6.1, the wellhead can be removed down to but not including the CHF.

6.6.3 – Protection of exposed CHF

For a suspended well where the wellhead has been removed the CHF and near-surface casings **shall** be protected against corrosion or damage.

6.6.4 – Inspection and maintenance

Suspended wells **shall** be inspected according to 6.3.5 (see page 111) and maintained in a safe condition for the period of the suspension.

6.7 Well site maintenance

The well site **shall** be maintained in accordance with Section 3 (starting on page 49) during well operations up to and including abandonment.

6.8 Well operation and maintenance records

The Well Monitoring Plans, risk assessments, well inspection, condition monitoring, and well maintenance records required **shall** be permanently stored by the well owner. Records of workover operations and other wellhead maintenance **shall** comply with the requirements of 5.13 (see page 106) and provisions of 1.8 (see page 10).

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7 WELL ABANDONMENT

7.1 In this section

This section covers the considerations and requirements when abandoning wells.

7.2 Purpose and requirements for abandonment

A well may be abandoned for one or more of the following reasons:

- (a) Resource management, including reduction of draw-off and flow between different sections of a reservoir;
- (b) The well has reached the end of its useful life;
- (c) Well components have failed or deteriorated in a manner that renders the well potentially unsafe or not economically repairable; or
- (d) The well is to be unused for a long period (particularly where the well is located in an aggressive environment requiring frequent repair or maintenance).

The abandonment of a well requires sealing it in a permanently safe manner which precludes the possibility of any internal well flows from the reservoir to shallower formation or to surface. Permanent structures **shall** not be placed over abandoned geothermal wells. There **shall** be no provision for future reinstatement.

7.3 Well assessment prior to abandonment

The condition of the well components as they may affect either the abandonment operation or the long-term effectiveness of the abandonment **shall** be assessed from existing records. Investigations **shall** provide sufficient understanding of the well condition before planning and executing the abandonment operation. Information **shall** be gathered on:

- (a) Static downhole temperatures;
- (b) Static water levels and pressures;
- (c) Any annulus between casings which is not sealed; and
- (d) Any changes in heat flow on or adjacent to the well site, which may be associated with deterioration of well components below ground level.

7.4 Abandonment operations

7.4.1 Drilling wellhead

A drilling wellhead including BOPs **shall** be used during abandonment operations.

7.4.2 Quenching

The well **shall** be quenched according to 6.5.2 (see page 116).

7.4.3 Preventing interzonal flow

Where an objective of abandonment is to prevent interzonal flows below the production casing, then the well **shall** be backfilled from total depth to the production casing shoe. This **should** be done with granular heat-resistant materials (for example, fine gravel) which are graded to give a low porosity and placed in a manner which does not cause bridging of the hole during emplacement.

7.4.4 Design of cement plugs for abandonment

In a permanent abandonment, cement plugs that are continuous over the length of the casing **shall** fill the production casing. The bottom of the cement plug **shall** be set as close as possible to the production casing shoe. Cement placement **shall** be programmed to minimise dilution of the cement slurry with fluids present in the well. Cement materials **shall** be selected to provide minimum deterioration of the set cement with time.

Cement plugs **shall** be placed in stages from the production casing shoe up. Each stage **should** be allowed to set before placing subsequent cement plugs. The well **should** be monitored for losses or gas flows between stages and pressure tests **shall** be undertaken where practicable to determine the integrity of cement plug and casing.

Where conditions warrant, consideration **shall** be given to placing cement around the casing shoe of the deepest cemented casing.

7.4.5 Preventing annular flow to surface

Where an annulus outside the innermost cemented string of casing is suspected of being inadequately sealed and might allow interzonal flow or flow to the surface, then every reasonable attempt **shall** be made to seal the annulus by squeeze-cementing.

If the annulus cannot be squeeze-cemented from the surface, then perforation and squeeze-cementing or removal of the upper joints of casing prior to filling the well with cement may be considered.

7.4.6 Removal of cellar and casing

The cellar and casing **shall** be removed to a depth below ground level that is unlikely to affect future ground use.

NOTE

Permanent structures *should* not be placed over abandoned geothermal wells.

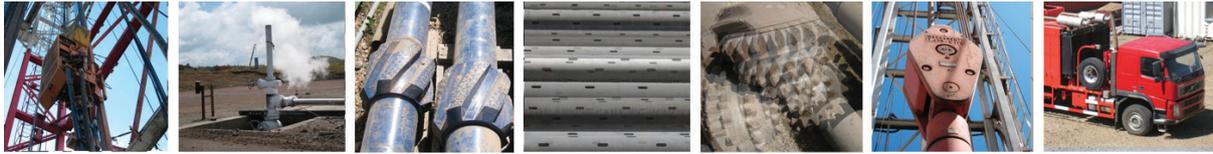
7.5 Well abandonment records

Following permanent abandonment, the well owner **shall** survey and permanently store the elevation and plan location of the top of remaining casing.

7.5.1

Records of abandonment operations **shall** comply with the requirements of 5.13 (see page 106) and provisions of 1.8 (see page 10).

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APPENDIX A – Consolidation grouting

(Informative)

A1

This appendix provides guidance for consolidation grouting where this is necessary to improve shallow conditions at the well site.

NOTE

- (1) Consolidation grouting can achieve the following:
 - (a) Increase the load bearing capacity of shallow formations;
 - (b) Reduce the frequency and severity of fluid losses while drilling the initial part of the well; and
 - (c) Strengthen the formations immediately below the drilling equipment so that if a blowout results in geothermal fluids flowing up outside any casings, then the flow is diverted away from the drilling equipment via the weaker material outside the volume of grouted material.
- (2) Some soil types can be damaged by consolidation grouting weakening the strata. Such soils would not normally be grouted.

A2

Consolidation grouting consists of a number of slim holes drilled and cement grouted in stages in a pattern. The hole pattern final depths are designed so that the volume consolidated approximates an inverted cone of base diameter centred on the well and which includes the area occupied by primary drilling equipment. See Figure A-1 for a typical layout of consolidation grouting.

NOTE

This can be achieved by drilling 100 mm diameter holes in a regular pattern centred on the proposed well centre. Holes closest to the well would terminate at 30 m, holes furthest from the well at 10 m, and holes in between would terminate between 10 and 30 m. Each stage would not exceed 5 m in length and applied pressures need to be limited to avoid fracturing the formation or causing uplift (for example, 10 kPa per metre of depth to the top of the stage being cemented).

A3

Alternate (primary) holes should be advanced and cemented in 5 m stages. Intermediate (secondary) holes should follow.

NOTE

The drilling and cementing of secondary holes provide an indication of the reduction in permeability achieved by the primary holes. If no reduction is achieved then additional infill tertiary holes are likely to be needed within sections of the total pattern.

Figure A-1
Typical layout of consolidation grouting

