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Well Cement Integrity and Cementing Practices

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Abstract

The integrity of petroleum wells is important in protecting the environment from uncontrolled flows of hydrocarbons.

This report reviews the current state of knowledge of issues that may affect the integrity of well cements from the design, placement, through their operational life and long into the future.

The potential mechanism for direct contamination of aquifers (with flow-back fluids, formation waters) from hydraulic fracture stimulation when approximately 2000 m of rock exists between aquifers and petroleum reservoirs is extremely unlikely. The natural migration and leakage of biogenic or thermogenic gas from behind the well casing are more likely.

The down hole environment (temperature, pressure, formation water chemistry) will govern the design of the cement slurry and impact on the performance across the full lifecycle of a well.

The density and rheological properties will determine the success of the initial placement of the cement. Understanding the current state of the art in well placement procedures to minimize mixing of fluids with the cement slurry and the creation of mud channels is imperative to achieve As Low as Reasonably Practicable risk in the construction of wells.

During the operational life, variations in temperature and pressure will occur. Knowledge of the behaviour of the set cement material due to the curing temperature and pressure and thereafter changes in the material response (stiffness, ductility etc) owing to changes in temperature and applied stresses, including fatigue degradation due to loading cycles, is vital in ensuring the reliability of well designs.

Portland cements are known to have the potential to degrade in aggressive chemical environments, the down hole chemistry and its interaction with the cement sheath is therefore of paramount importance in ensuring integrity of a well is maintained long after the well has been decommissioned.

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Chapter 1

Introduction

Oil and gas have been successfully explored, developed and produced from various areas in South Australia for over 50 years, including extensive use of hydraulic fracture stimulation in the Cooper Basin since 1969. To date, there have been no reported significant environmental issues as a result of oil and gas operations in South Australia (South Australian Department of State Development, Energy Resources Division, 2015).

The large scale development and production of hydrocarbons from unconventional resources in North America through increased use of horizontal wells combined with hydraulic fracture stimulation has led to environmental concerns. Therefore, a study of well cement integrity and cementing practices has been performed to address public concerns that the environmental objectives set out by state regulation in the *South Australia Petroleum and Geothermal Energy Act* (Government of South Australia, 2000) and *South Australia Petroleum and Geothermal Regulations* (Government of South Australia, 2013) can be achieved.

The design of a well is dominated by the prevailing environmental conditions. The cement slurry is designed with due consideration of the ambient temperature, pressure, host formation rock and pore fluids in the rocks penetrated by a wellbore (e.g. formation waters, non-hydrocarbon gases and hydrocarbons). The slurry design will subsequently affect the performance of the well in achieving zonal isolation throughout the lifetime of the well (from initial placement, through it's service life and into the long term) as shown in figure 1.1.

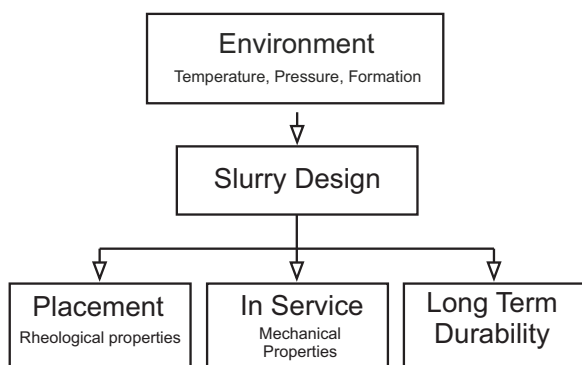


Figure 1.1: Project overview

In the short term, the slurry design is required to balance hydrostatic and hydrodynamic pressures from the formation and the drilling muds that it will displace in the placement process. The placement aspects of well construction will be addressed in chapter 2. The performance of wells under service conditions is discussed in chapter 3. Aspects of cement slurry composition and chemical reactions (hydration) will be addressed in chapter 4 along with a review of factors affecting the long term durability of well constructions beyond the service life.

1.1 Background

The design of a well cement job, is conducted by balancing the hydrostatic pressures of the cement slurry with the pore pressure and formation fracture pressure, as shown in figure 1.2. The pressures are further checked using a well cement placement simulator to ensure that dynamic pressure during the pumping of cement are not problematic.

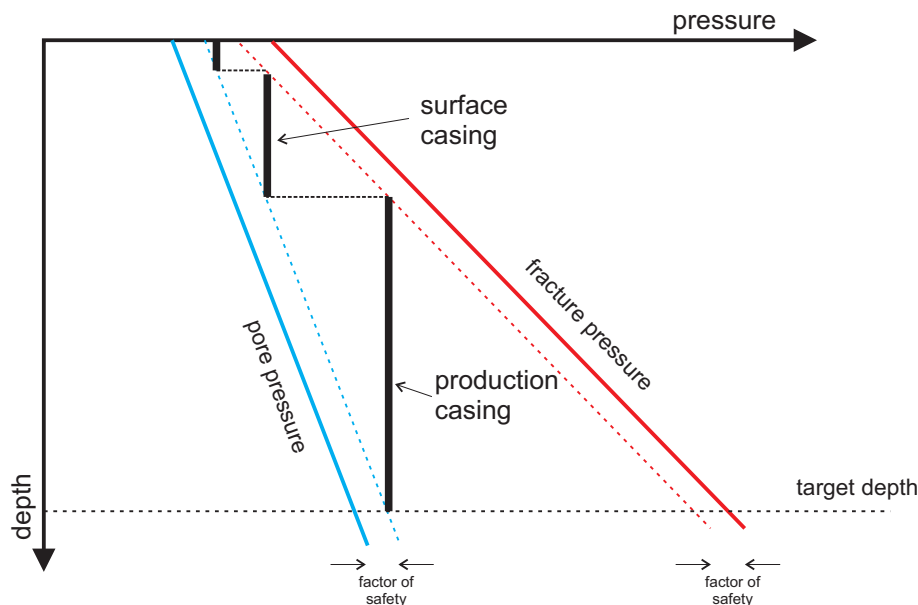


Figure 1.2: Well design - balancing of pressures

The *pressure window* between formation pore fluid pressures and the pressure required to fracture the formation rock will dictate the well architecture that is required. In the Cooper-Eromanga basins in South Australia, for example, a typical well is constructed with a short depth of *conductor casing* inside of which is a string of *surface casing*, followed by *production casing*. In many oil and gas basins, with a tighter pressure window, a further *intermediate casing* is also required to maintain the pressure balance to get to the desired depth.

A well bore is drilled to the desired depth of a given casing, during drilling the well bore is kept stable by keeping the bore filled with fluids to balance the pressures. After drilling a *casing string* (a number of lengths of tubing connected together) is placed into the well. When the full length of the casing string is in place the cement can be pumped into the well.

The existing drilling fluid is displaced from the main bore with the use of well cleaning fluids, which is designed to clean deposits of mud from the steel casing and from the formation rock. After well cleaning is complete a *spacer* fluid and the *cement slurry* are pumped through the central hole as shown in figure 1.3, and travels around the bottom of the casing and into the annular gap. The spacer fluid is designed to prevent contamination of the cement slurry with any muds.

Figure 1.4 shows a schematic of the final well construction. The well bore will not be perfectly vertical. The deviation from vertical, along with the amount of, and spacing of *centralizers* used in the well design will determine how concentric the casing strings are at a given location. The cement slurry can consist of predominantly two different cement mixes, a lower density lead cement and higher density tail cement to aid cement placement. The higher density tail

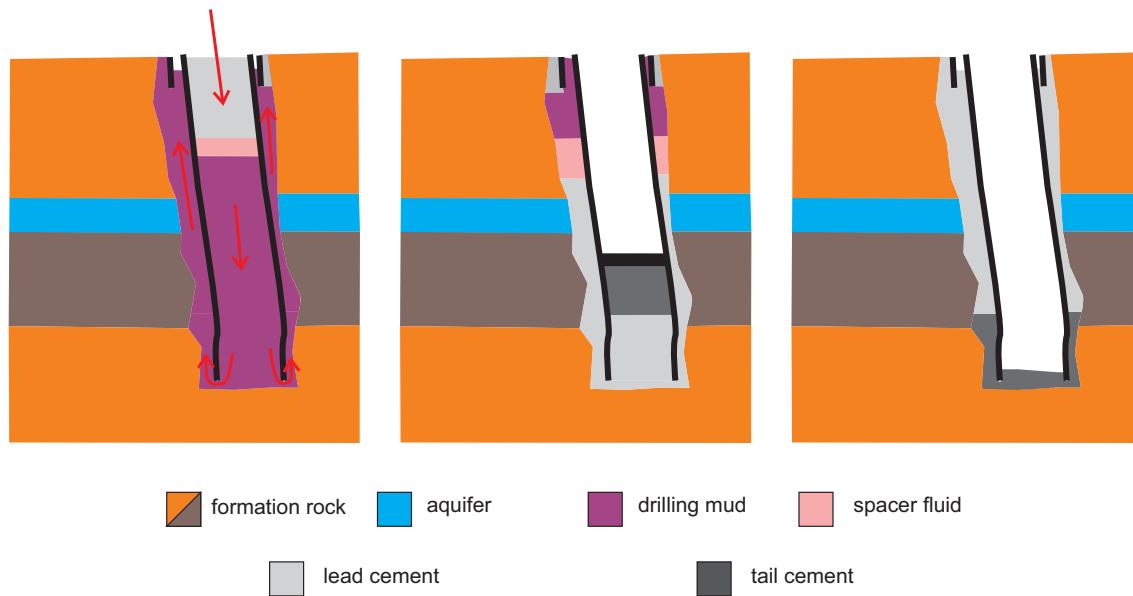


Figure 1.3: Cement placement

cement has superior strength properties to isolate hydrocarbons and permeable zones.

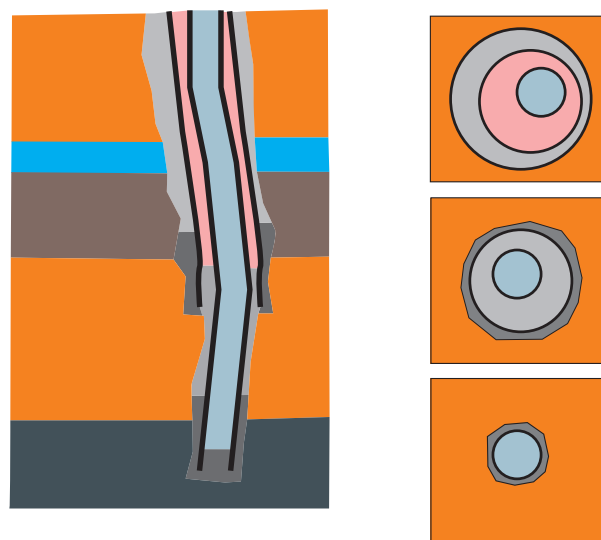


Figure 1.4: Schematic of a typical well

1.1.1 Well leakage pathways and sources of fluids

The interested reader is directed to the paper by Bonnett and Pafitis (1996), which gives a good overview of the migration mechanisms throughout the life of a well. The ideas presented in that paper, and reiterated by subsequent authors on the topic, are briefly presented here.

The leakage pathways by which fluids can potentially travel from a hydrocarbon reservoir up

to aquifers or the surface are shown in figure 1.5, which is reproduced from Celia et al. (2005), are:

- (a) between cement and outside of casing
- (b) between cement and inside of casing
- (c) through cement
- (d) through casing
- (e) in cement fractures
- (f) between cement and rock

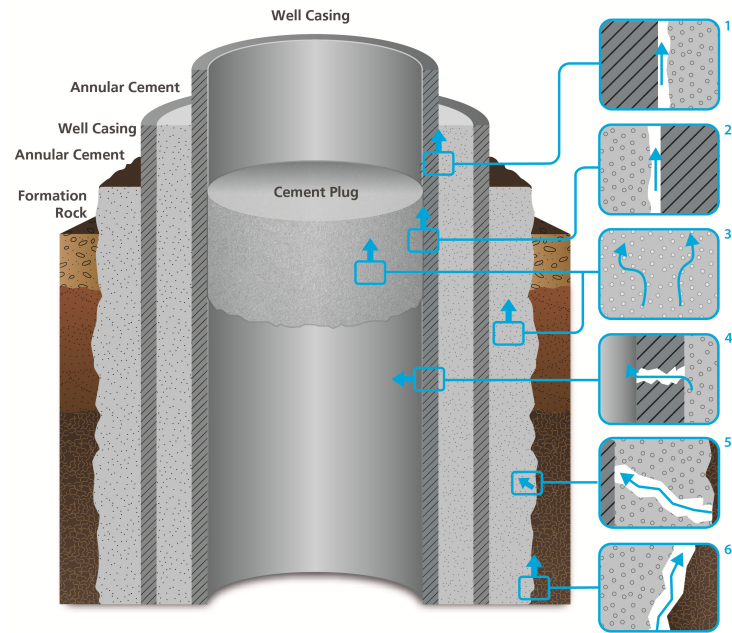


Figure 1.5: Potential leakage pathways, Celia et al. (2005)

The mechanisms (a), (b) and (f) describe transport through micro annuli, where tiny gaps between the components become the preferred flow path. In addition to the leakage pathways identified above, the potential pathway through mud channels in the cement sheath as a result of poor placement has been identified by this study and is discussed further in chapter 2. As can be seen in figure 1.5, contamination of aquifers or fluids reaching the surface may require a combination of the leakage pathways to occur.

The potential sources of fluids are (Davies et al., 2014):

- (a) a gas rich formation, such as coal
- (b) non-producing, gas- or oil-bearing permeable formation
- (c) biogenic or thermogenic gas in shallow aquifer
- (d) oil or gas from an oil or gas reservoir

and are shown in figure 1.6.

In order for fugitive emissions to occur both a fluid source and a pressure gradient must be present for transport to occur (Davies et al., 2014).

1.1.2 Well leakage occurrences

When discussing well failures it is instructive to distinguish between *well barrier failure* and *well integrity failure* (King and King, 2013). A well consists of a number of well barrier elements, for example the cement sheath, the casing strings, seals and valves. The failure of one of these barriers is coined a well barrier failure, but does not necessarily lead to well integrity failure. Well integrity failure is the unwanted consequence of all barriers in a sequence occurring that can cause a leakage pathway.

A risk analysis was performed by Ingraffea et al. (2014) of wells drilled in Pennsylvania from 2000-2012. From analysis of 75505 compliance reports for 41381 oil and gas wells they found loss of well integrity in 1.9% of production wells spudded (start date of drilling) between 2000 and 2012, and higher failure rates occurred in the North East counties. It should be noted that the statistical analysis presented in this paper is hotly contested as is the use of the terminology of *well integrity failures* instead of *well barrier failures*.

The CSIRO measured emissions from coal seam gas (CSG) (Day et al., 2014), 43 wells (less than 1 % of CSG wells across Australia) were selected for analysis, from a number of gas fields throughout New South Wales and Queensland. They concluded that emissions from zero to 44 g min^{-1} , the method employed was thought to show emission rates of less than $1 \times 10^{-7} \text{ g min}^{-1}$ could be reliably quantified. The highest emission being from a vent on a well pad and the lowest from two plugged and abandoned wells and a suspended well, the decommissioning of wells beyond their productive life is discussed further in 4.

Current approaches to decommissioned wells in Australia and internationally and management of the legacy were investigated (New South Wales Chief Scientist and Engineer, 2014). They concluded that integrity is considered low risk over decades as also found by a UK review jointly conducted by The Royal Society and The Royal Academy of Engineering (2012), but little research has been conducted over 1000+ year time scales.

Davies et al. (2014) analysed data from around the world to find occurrences of well barrier and well integrity failure. They found that well barrier or well integrity failure rates vary from 1.9% to 75%. This demonstrates the wide range of integrity or barrier failures reported, the statistics can be highly skewed by the geology and age of a given field and if barrier failures are included. The 75% figure quoted is for the Santa Fe Springs oilfield in California and is for integrity failures, which were observed from gas bubbling at the surface. This field was discovered in 1921 (Chilingar and Endres, 2005) and would have included particularly old construction and

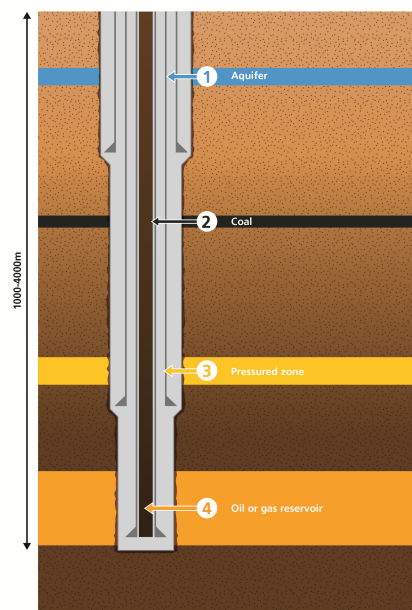


Figure 1.6: Potential sources of fluids, after Davies et al. (2014)

decommissioning techniques although the precise details of the well constructions and their ages is not given in the paper to allow a comparison with modern standards.

1.1.3 Risk

There are many definitions of *risk*. In engineering and occupational health and safety, the definition that

$$\text{Risk} = \text{Probability or likelihood of occurrence} \times \text{loss or consequences} \quad (1.1)$$

is often used. In the context of well integrity, Norwegian industry standards (NORSOK, 2013) define risk as the *combination of the probability of occurrence of harm and the severity of that harm*. Figure 1.7 shows how an acceptable level of risk is determined.

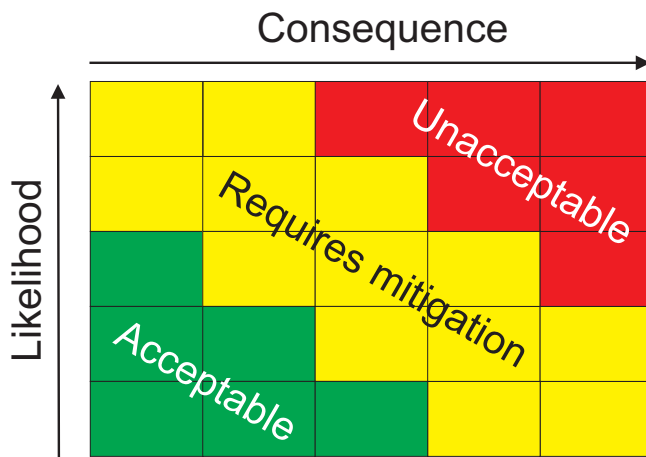


Figure 1.7: Risk assessment matrix

The likelihood of uncontrolled flows will be dependant upon how challenging the geology is in a given basin and the effectiveness of well construction to meet the objectives of creating and sustaining zonal isolation. The environmental consequences associated with potential uncontrolled flows from a petroleum well is very much dependant upon the geographical location of the well, the well construction standards and methods applied and the extent of any seepage from the well.

Legislation in South Australia (Government of South Australia, 2000, 2013) exerts that **As Low As Reasonably Practicable** risk *ALARP* is the minimum allowable standard for activity approval. Part 12 of The South

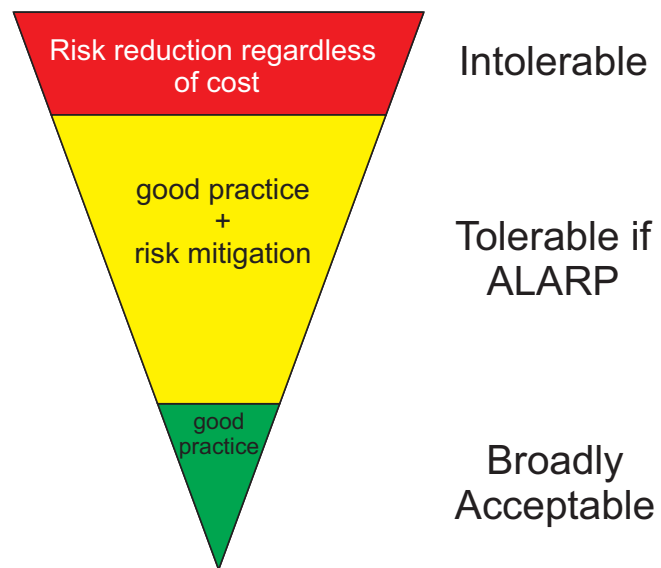
Australian Petroleum and Geothermal Energy Act (Government of South Australia, 2000), pertaining to environmental protection, states that in carrying out regulated activities, licensees:

- ensure that regulated activities that have (actually or potentially) adverse effects on the environment are properly managed to reduce environmental damage as far as reasonably practicable; and
- eliminate as far as reasonably practicable risk of significant long term environmental damage; and
- ensure that land adversely affected by regulated activities is properly rehabilitated.

As Low As Reasonably Practicable is a legal term that has arisen from safety practices and legislation in the United Kingdom (Government of the United Kingdom of Great Britain and Northern Ireland, 1974). In UK law, the term *reasonably practical* is used to mean that the risks need to weighed against the measures that would need to be undertaken to reduce / eliminate them and that these measures should not be *grossly disproportionate* in comparison to

the benefits gained. This is not a process of balancing cost and benefits however, it is presumed that measures to reduce risk will be implemented unless they can be demonstrated to be grossly disproportionate.

Figure 1.8 demonstrates the ALARP principle. Practices become higher risk than are considered as low as reasonably practicable with research and practical experience, therefore the intolerable zone increases as “solutions can be employed in a more logical and cost effective way” (Bonnett and Pafitis, 1996). This concept is exemplified in the context of pollution (leaks to the environment) from oil and gas wells by King and King (2013), and table 1.1 is reproduced, in abbreviated form, from their paper. As technology and working practices have evolved with time the potential for pollution has reduced and the threshold of the intolerable zone of risk in figure 1.8 moves downwards.



Time era (approx)	Operation norms	Figure 1.8 Potential for pollution
1820's - 1916	Cable tool drilling, no cement, wells openly vented	high
1916 - 1970	improvement in cement isolation	moderate
1930's to present	Rotary drilling, pressure control systems	moderate
mid 1960's to 2000	Improvement in gas tight couplings and joints	moderate (vertical wells), improving for horizontal wells
mid 1970's to present	Cementing improvements including cement design software	lower
1988 to present	Multi-frac horizontal wells, lower toxicity chemicals	lower
2005 - present	Well integrity assessments, premium couplings	Lower, particularly with strengthened state laws (US)
2008 - present	Reduced chemical hazard in fracturing chemicals, studies into real time well integrity tools	Lowest yet - increased design and inspection requirements

Table 1.1: Approximate time line for pollution potential by era, after King and King (2013)

1.2 Key questions addressed

Figure 1.9, shows the time line of a well, and leads to the key questions that require addressing in assessing the integrity of well cement over its entire life.

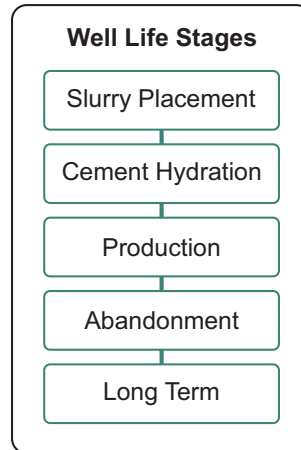


Figure 1.9: Lifestages of a well

- What is current best practice in cement placement operations and the behaviour of cements during placement to achieve isolation?
- How is the structural integrity of the cement sheath, to resist changes in pressures and temperatures during its operational lifetime, considered in well design?
- What are the properties and chemical compositions of cements for different environments to achieve zonal isolation?
- How can the integrity / condition of the cement sheath, subject to down hole environment, be assessed or predicted in the long term?

By addressing the key questions posed, key challenges and solutions to cement integrity will be identified for further investigation.

Chapter 2

Cement placement

In order to achieve proper zonal isolation and restore the natural barrier that was altered during drilling, adequate cement placement is critical. The key parameters in that process are:

- **Sufficient cement coverage** - the volume of slurry should be enough to bring the top of cement (TOC) above the zone(s) of interest where fluids could flow from / to (i.e. aquifers, hydrocarbon intervals).
- **Proper well conditioning** - the casing stand-off, fluid designs and placement pumping rates should allow proper fluids displacement and interface in order to mitigate the risk of mud channelling and slurry contamination and in order to ensure the quality of the cement sheath in the annular across all critical intervals.

The factors affecting a good cement placement are summarised by Bittleston and Guillot (1991) as:

- Wellbore geometry
- Cement slurry
- Centralization
- Mud conditioning
- Casing movement
- Washes / Spacers
- Cementing plugs
- Other casing hardware

and will be examined in more detail below.

2.1 Influence of the drilling process on successful zonal isolation

The success of a well cementing job begins with the quality of wellbore construction. Achieving a quality wellbore in terms of consistent gauge (diameter of the bore), minimal rugosity (small

scale variations on the surface of the wellbore surface) and the stability of the wellbore (Brufatto et al., 2003). During the drilling process the careful selection of appropriate drilling fluids for the given wellbore conditions is crucial to achieve good cleaning of the wellbore and minimise wellbore erosion (washouts, chemistry). The fluid hydraulics is crucial for this purpose, the engineers have control over:

- fluid density
- rheological properties
- frictional pressure losses
- flow rates

The drilling process may cause some damage to the formation. The cement slurry is a very dense fluid and a bad cementing job may cause fractures in the formation, hence the requirement to balance hydrostatic and hydrodynamic pressures as discussed in section 1.1 in describing the pressure window.

2.2 Sufficient cement coverage

2.2.1 Open hole (OH) size and determination of slurry volume

While drilling through different rock formations (hard, soft, unconsolidated), the hole diameter will inevitably vary from the drill bit diameter. To account for these variations (presence of wash-outs or tight spots), an excess volume is added to the theoretical volume of slurry. In the planning phase of a well, this excess is typically based on offset wells data and can vary between 25% annular excess (production hole) to up to 200-300% annular excess (surface hole where rocks are unconsolidated). These figures can be revised as necessary while drilling by collecting actual data (when available) through (Rae, 1990):

- Fluid caliper measurements
- Logging while drilling (LWD) data
- Wireline caliper log (1 arm to 6 arm caliper).

The degree of accuracy of these methods vary and a safety factor should always be accounted for to ensure sufficient cement coverage.

2.2.2 Lost circulation

Any fluid losses into the formation during a cement job could lead to a reduction in the height of the cement column, which could compromise coverage of the zone(s) of interest and could potentially lead to serious well control issues. Every effort should be made to mitigate that risk, which means (Baret et al., 1990):

- Fixing existing losses (if any) prior the cement job by sealing permeable formations
- Pumping excess quantities of cement to ensure that any small losses (not uncommon) do not compromise the overall cement coverage objectives

- Assessing the risk of induced losses during the cement job (static and dynamic security) and adjusting the design of the fluids and pumping rate accordingly: while pumping at a faster rate might enhance mud removal, the subsequent increase in friction pressure in the annulus combined with the increase in hydrostatic from the slurry column could lead to fracturing the formation and inducing losses. If the pressure window as illustrated in figure 1.2 is narrow, the addition of lost circulation material (LCM) in the fluids or performing two-stage cement jobs may be considered.

2.2.3 Verification of top of cement (TOC)

The top of cement can be verified visually when returns to surface are anticipated. Alternatively, the final lift pressure (differential in hydrostatic pressure between the annular and the inside of the casing) can give an indication of the actual top of cement, which can be verified later with a cement bond log or equivalent. Evaluation of the cement job is considered further in section 2.6.

2.3 Well conditioning

The type of mud used affects greatly the challenges faced during mud removal. In order to remain focused on South Australia, only water based muds will be considered in this section.

In order to provide complete zonal isolation, the drilling fluids and spacers (if any) need to be fully removed from the annulus and replaced by good quality slurry all around the casing during a cement job (Chen et al., 2014). Improper mud removal can result in mud channels in the annulus as shown in figure 2.1 and/or contamination of the cement slurry which would both compromise complete and permanent zonal isolation. Channelling would create a path for the formation fluid to flow through, allowing interzonal communication, figure 2.1 shows a) examples of bad cement placement due to low stand-off and b) good placement with acceptable stand-off (Kimura et al., 1999). Contamination of the slurry would alter both the slurry properties and the set cement properties which could compromise both well control and well cement integrity. Mud removal is affected by three different processes:

- Hole cleaning while drilling, ensured by controlled and optimized mud properties, regular wiper trips and good overall drilling practices to optimize hole geometry and stability (i.e. minimize wash outs, tortuosity, dog-leg severity and maintain well control)
- Mud conditioning prior to the cement job, to break gel strength, lower rheologies if necessary, reduce drilling solids and circulate out gas bubbles if any. It is recommended to circulate out at least 1.0 times (Bittleston and Guillot, 1991) (with even 1.5 to 2 times being suggested anecdotally) bottoms up to ensure there are no static pocket of muds in the annulus and that there is flow all around (improved circulation efficiency).
- Mud displacement from the annulus during the cement job is achieved by:
 - proper centralization
 - optimisation of the fluids design and placement
 - enhanced by pipe movement if possible.

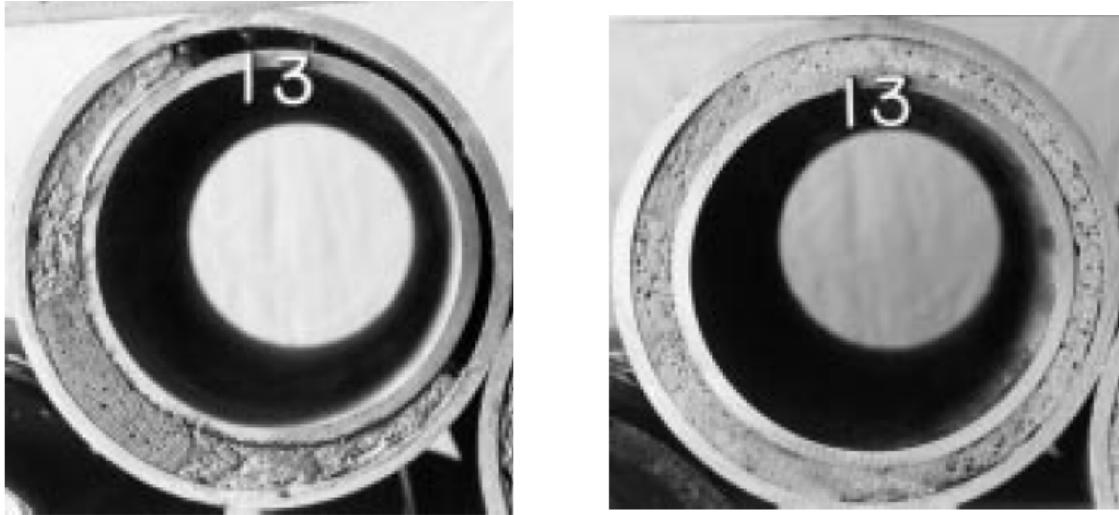


Figure 2.1: Mud channeling during cement placement, Kimura et al. (1999). a) poor placement and low stand-off, b) good placement and high stand-off

The displacement efficiency parameters and best practises, which have a direct impact on the cement quality in the annular are now focused on.

2.3.1 Centralization and stand-off

Jones and Berdine (1940) showed that casing eccentricity had an impact on cement channelling through the mud and proposed to centralise the casing to promote all-round cement coverage. The casing eccentricity is represented by the casing stand-off (STO) as shown in figure 2.2, and defined as

$$\text{Standoff} = \frac{\text{Actual clearance}}{\text{Concentric clearance}} \times 100 \quad (2.1)$$

100% stand-off means that the casing is perfectly centralized in the open hole (OH) and 0% means that the casing is lying on the low side of the OH. The lower the stand-off, the harder it is to remove the mud on the narrow side of the annulus and the greater the risk of cement channelling through the mud on the wide side of the annulus as shown in figure 2.1.

Some challenges are encountered while optimizing the stand-off:

- **Hole geometry** - The presence of wash outs (erosion of formation) or tight spots: in a large annular gap (space between the formation wall and the casing), providing good centralization might be difficult (floating centralizers); whereas tight spots could result in challenges running casing with many centralizers (increased drag). Bittleston and Guillot (1991) recommend that the borehole ideally be 3 inches (diameter) larger than the casing and a minimum of 1.5 inches larger than the casing and free of washouts.
- **Trajectory** - Deviation and tortuosity of the well, as shown in figure 1.4, have a detrimental effect on stand-off (STO) (Sanchez et al., 2012; Fry and Pruett, 2015).
- **Centralisers** - the type of casing centralisers employed as well as the number and spacing of the centralisers.

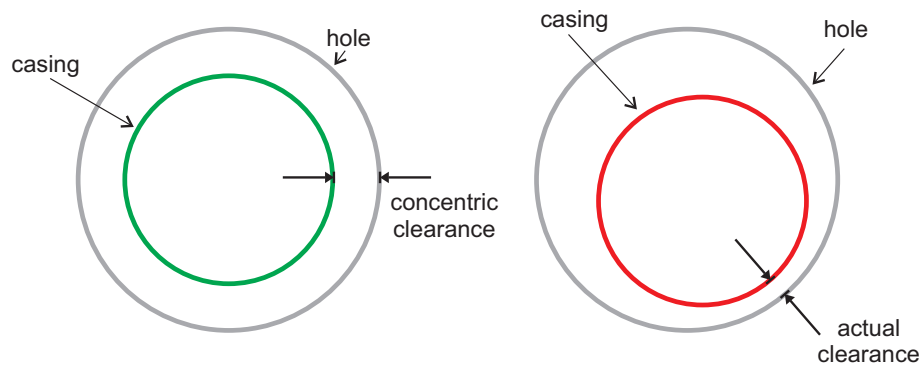


Figure 2.2: Casing stand-off

Since 1940, simulation models have been developed to predict casing stand-off during a cement job and optimize the type and placement of the centralizers (Liu and Weber, 2012). Although there is a general consensus to target a minimum of 70-75% stand-off (Bittleston and Guillot, 1991) from total depth (TD) up to and across the zones of interest, well cleaning engineering software simulations should be used to indicate if deviation from this minimum range are recommended (on a case by case basis). Smith (1987) state that centralizers are one of the few mechanical aids covered by API specifications (API specification 10D, 2015).

The casing eccentricity is also be an important parameter to consider when looking at the cement sheath around the casing and on stress concentrations during the life of the well and is discussed further in chapter 3.

2.4 Fluids design and placement

Washes / spacers are often used between the mud and cement slurry to isolate mud and cement when their fluid properties are incompatible and to enhance the mud removal.

The effects of incompatibility could be increases in viscosity (increase in “thickness of a fluid”), flocculation (where small particles in a fluid form lumps), solid settling, cement setting too fast or not setting at all or not building enough strength. Specific criteria are used to quantify that risk / effect (looking at the rheology of the mixtures versus the original fluid). If the mixtures exhibit lower or similar viscosity without sedimentation, the fluids are compatible. Any significant increase in viscosity would create issues while pumping (increase in friction pressure leading to fracture of the formation or un-pumpable mixture leading to job failure or challenging mud removal leading to poor cement placement). Hence the need to mitigate the risk of mud-slurry contamination by using spacers compatible with both mud and slurry and by using mechanical separators (wiper plugs in front and behind the cement inside the casing, where gravity would make the slurry fall through the fluids ahead due the density gradient).

The degree of compatibility between fluids is determined via a series of tests on the fluids mixtures (in %: 100/0, 95/5, 75/25, 50/50, 25/75, 5/95, 0/100). The most usual tests measure rheology, gel strength, stability (sedimentation), compressive strength, thickening time (API RP 10B-2, 2013). Slurries and mud are always presumed to be incompatible e.g. the intermixing of these two will have a detrimental effect on their properties. Hence the need to

have a spacer in between. Spacers are designed to be compatible with both.

Washes are pre-flushes with a density and viscosity very close to that of water. Like water, washes exhibit Newtonian fluid behaviour (low resistance to flow). These spacers are designed to be turbulent-flow spacers, which means their well cleaning efficiency depends on achieving a minimum critical flow rate to ensure turbulent flow. The recommended volume should be sufficient to have 10 minutes contact time in the annulus across the zones of interest. Both the critical rate and contact time can be verified using engineering simulation programs. Un-weighted spacer lightens the column of drilling fluid in the annulus (loss of hydrostatic pressure) and well control should be verified before use.

Weighted viscosified spacers are designed to work in effective laminar flow conditions. Effective laminar flow enhances fluid displacement by promoting a relatively flat interface in between the fluids (piston like displacement). In most cases, this will require to remain within a given pumping range for a given open hole size and given stand off. Such spacers therefore need to be designed and engineered carefully and will need (as a minimum) to satisfy a specific density and rheology hierarchy as shown in table 2.1.

$$\begin{array}{llll} \text{Density (mud)} & < & \text{density (spacer)} & < & \text{density (slurry)} \\ \text{Rheology (mud)} & < & \text{rheology (spacer)} & < & \text{rheology (slurry)} \end{array}$$

Table 2.1: Density and rheology hierarchy

These hierarchies might be difficult to achieve with sufficient increments when there is a narrow drilling window (very close pore and fracture pressures), when cementing long intervals with a narrow annular gap (increase in friction pressure which might induce losses at a normal pump rate).

A combination of both type of pre-flushes can be used to optimize well cleaning, prevent slurry contamination (Power et al., 2000; Guillot et al., 1990) and ensure well control.

Advanced displacement and well cleaning simulators should be used to assess the efficiency of the pre-flushes and the risk of channelling and fluid contamination. The pumping rate or minimum stand-off requirement might need to be adjusted based on such simulation outputs, to achieve the desired flow regime. Brufatto et al. (2003) for example, compare the results from a well placement simulator where a low stand-off is achieved in figure 2.3 resulting in low cement coverage at the top of the casing and a clear mud channel lower down with a successful cement job achieved with high stand-off in figure 2.4.

2.4.1 Pipe movement

Studies and simulation software indicate that pipe rotation (3 to 10 r.p.m.) and / or reciprocation (vertical movement) during wellbore conditioning and cementing operations improve the circulation and displacement efficiency. This facilitates cement placement. Due to operational concerns, pipe movement is however often limited. Reciprocation may also create surge and swab pressure which need to be evaluated for well control purposes. Surge pressure increases the pressure in the cement and hence reduces the safety margin to the fracture pressure, conversely the swab pressure reduces safety margin from the pressure in the cement to pore pressure.

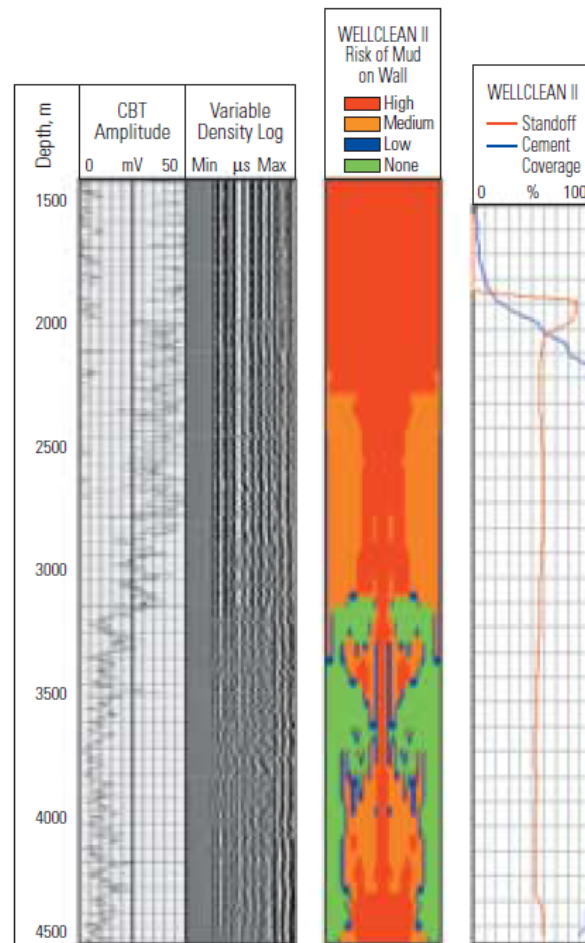


Figure 2.3: Example of a well placement simulation with poor zonal isolation, Brufatto et al. (2003)

2.5 Cement setting

When the cement has been placed, if the slurry mix is unstable, the free water in the slurry mix has the potential to ‘bleed’ and possibly form a channel within the cement (Brufatto et al., 2003). This phenomena is known as slurry instability.

As cement sets it undergoes a transition from fluid to solid state. The volume occupied by set cement is a smaller volume than the liquid slurry. This shrinkage can lead to a reduction in the cement pressure which if lower than the formation fluid pressure can lead to gas migration into the cement. A cement slurry is usually designed to achieve overpressure compared to the formation pore pressure for this purpose. Conversely, too much overpressure can lead to loss of cement mix water into permeable rock layers.

Cement shrinkage leads to volumetric reduction and can consequently lead to de-bonding between cement and casing or the formation. The shrinkage can also result in tensile cracks and consequently increased permeability to provide a migration path for fluids. Additionally, circumferential fractures may be created because of cement shrinkage leading to gas accumulation

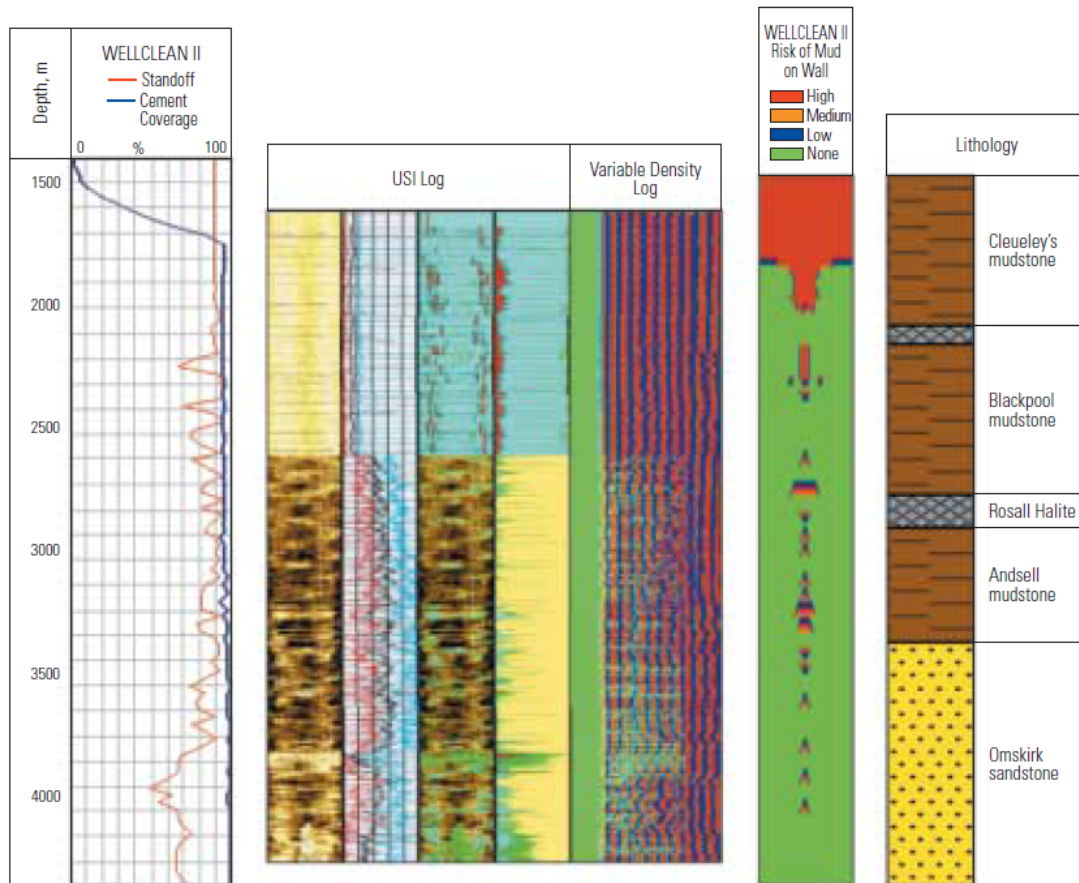


Figure 2.4: Example of a well placement simulation with good zonal isolation, Brufatto et al. (2003)

after the cement has set. The determination of shrinkage and expansion of well cement formulations is the subject of API standards (ISO10426-5, 2004), but only at atmospheric pressure.

Backe et al. (1998) designed an experimental method to measure slurry shrinkage, which was sensitive enough to measure shrinkage from hydration. There was a clear correlation between total chemical shrinkage and cement content. Zhang et al. (2010) performed experiments with water/cement ratios (W/C) ranging from 0.25 to 0.4, and temperatures 10 - 60° C. These experiments measured shrinkage, degree of hydration and setting time. Using a “boundary nucleation and growth model” they obtained good fits to chemical shrinkage data.

Thiercelin et al. (1998) performed instrumented annular experiments, using two concentric 1 mm thick and 80 mm high steel cylinders with external diameters of 111 mm and 196 mm. The cement was poured in the annular space after the steel cylinders had been heated to 77 ° C, a diagram of the experimental set up is shown in figure 2.5.

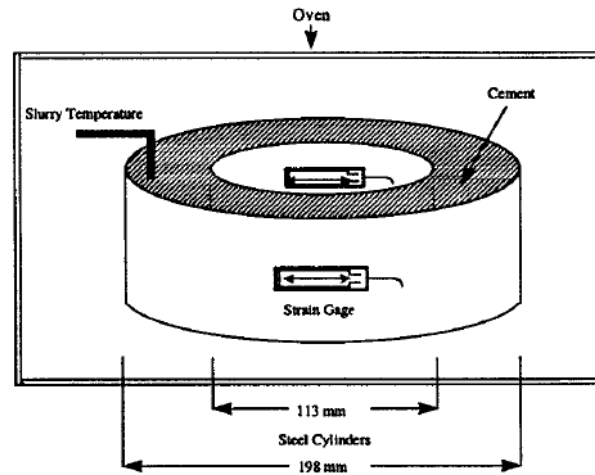


Figure 2.5: Instrumented annular shrinkage experiments, Thiercelin et al. (1998)

2.6 Placement quality assurance

Several evaluation techniques exist to verify whether the objective(s) of the cement job have been achieved. The selection of the evaluation technique(s) to use for a specific cement job will be dictated by the specific objectives, which vary from string to string as shown in table 2.2.

Casing type	Main objective
Conductor casing	Isolate unconsolidated surface formation
Surface casing	Seal off aquifer, support subsequent string and allow further drilling
Intermediate casing	Seal off depleted and/or over-pressure formation(s) and allow further drilling
Production casing	Provide zonal isolation of hydrocarbon intervals and prevent fluid migration

Table 2.2: Objectives in casing string design

An overview of available evaluation techniques (Smith, 1987) is itemised below.

- Temperature survey - uses the heat of cement hydration to locate cement behind casing.
- Noise log - can be used to locate fluid movement behind casing.
- Radioactive-Tracer surveys - tracer is added as a soluble salt to the cement mixing water.
- Bond logging - acoustic signal is transmitted into the casing, the arrival time and amplitude of the received signal are used to determine the bonding conditions.

Some techniques will only allow the determination of the top of cement, or the verification of the hydraulic seal at the casing shoe. More complex techniques will establish a full cement

map / imaging. The main techniques of temperature logging and acoustic logging, along with pressure testing are elucidated in the following text.

2.6.1 Hydraulic testing

Hydraulic testing allows verification of the isolation provided by the cement (i.e. no communication path).

A *positive pressure test* is generally performed at the end of every surface and intermediate cement job. It consists of two steps:

- The *casing test* should be performed at the end of the cement placement (after bumping the top plug, while the cement is still a fluid) to prevent damage of the cement sheath. Pressure is applied and held to verify the casing integrity.
- The *formation integrity test* (FIT) or *leak-off test* (LOT) is performed once the cement has set and after drilling the casing shoe and a few meters of the new formation. The pressure is increased slowly inside the casing and monitored. A pressure drop could indicate a poor cement job and a remedial job (*squeeze*) may then be required across the casing shoe. If the pressure holds, the hydraulic seal at the casing shoe can be established.

A *negative pressure test* or *inflow test* consists of creating a depression inside the casing and to monitor any inflow/pressure variation to ensure the seal is established in both directions. This is only used in specific situations, for example *cement plug* evaluation, top of liner evaluation, squeeze evaluation.

2.6.2 Temperature logging

The temperature logging technique is mainly used to determine top of cement. As the hydration of cement generates heat, a temperature survey several hours after the cement placement would show an increase of temperature across the cement column. This increase in temperature might not be sufficient across the low-density cements such as extended lead cement to determine top of cement. The accuracy of this method also depends on wellbore geometry, formation temperature, length of the cement column and slurry design.

Temperature logs can also be used while a well is on production to assess fluid channelling behind the casing and identify the need for remedial cement job.

2.6.3 Acoustic logging

The acoustic logging method is the most commonly used to qualify a cement job. It can be run several hours or several days after the cement placement and evaluates the quality of the bond (acoustic coupling) between the casing, the cement and the formation. It measures the attenuation of the sound signal as it propagates through the casing, cement and formation and returns to the sensor. This technique will help spot free pipe, partially bonded or fully bonded pipe. For proper interpretation, the log data must be validated (Quality Assurance / Quality Control and tool calibration), compared with the expected log answer (based on the

cement expected acoustic properties at the time of the log) and correlated with actual job and well data. A typical acoustic log is shown in figure 2.6, where the various graphical outputs are showing where the top of column of cement sheath occurs. In the case shown this is the top of cement as designed and clearly detected, note cement sheaths are not required or sometimes desirable to extend to the surface on all casing strings, so long as geological zones of interest have sufficient coverage.

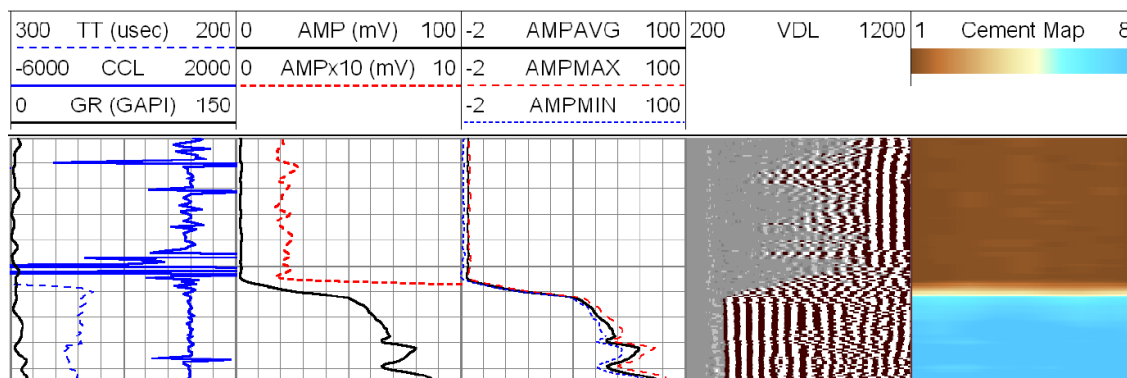


Figure 2.6: Typical acoustic/bond logs, taken from open file well logs in South Australia

If the presence of a microannulus is suspected, a sonic log should be run with and without pressurizing the casing. A comparison of the two attenuation rates should allow determination of the presence of a microannulus. If the **Cement Bond Log** (CBL, sonic log) does not improve with pressure, it is likely zonal isolation is compromised (presence of a larger microannulus or channel). A criticism of the acoustic logging technique is that a microannulus may not be detected if the casing is pressured, thus enforcing contact between the casing and cement even if the bond is compromised.

The distinction between contamination, microannulus and channeling can be ambiguous with sonic logs. The information might then be insufficient to determine the need / feasibility of a remedial cement job.

A more thorough evaluation can be obtained with ultrasonic imaging tool, whereby a rotating transducer is utilised to provide full coverage around the casing. This is superior to a linear transducer which will not provide a full picture. An ultrasonic tool will make a small part of the casing resonate and measure the echo response. If the pipe is free (i.e. there is fluid behind instead of set cement) it will “ring” (make a loud echo) as a large proportion of the signal will be reflected. However, if there cement is behind the casing, it will dampen the echo as a larger proportion of the sound wave will be transmitted through the cement. The effects will vary greatly depending on the slurry design and expected acoustic impedance of the set cement.

The ultrasonic imager will provide a qualitative and quantitative information of the nature of the material in the annulus, whether it is a liquid, a gas or set cement and can include percentage of each at each given depth. As for the sonic log, proper interpretation requires proper calibration of the tool, quality assurance and quality control of the log and correlation with the cement job data and well data (hole geometry, lithology, pipe stand-off, slurry design etc.).

Recent investigations into cement evaluation include an integrated approach to cement evalu-

ation (Enwemadu et al., 2012) and advanced techniques in integrated cement evaluation (Shaposhnikov and Findlater, 2013).

2.7 Gas migration

For formation fluid to migrate from a high-pressure zone to the surface or to a low-pressure zone, three conditions need to be satisfied simultaneously:

- The hydrostatic pressure in the annulus fails to compensate the pore pressure of the gas formation ($P_{hyd} \text{ column} \leq P_{pore} \text{ formation}$).
- Gas entry is allowed in the annulus (space of entry).
- Gas migration is allowed in the annulus (path of communication).

Several factors will act on these three conditions through-out the life of a well. In regards to cementing operations, three types of gas migration are considered:

- Immediate gas migration (during cement placement).
- Short-term gas migration (after cement placement).
- Long-term gas migration (after cement setting), this issue will be investigated in more detail in chapter 4.

Immediate gas migration can be easily mitigated by ensuring proper well control during the cement job (verification that dynamic and static fluid pressures remain between the formation pore pressure and fracture pressure). This requires good control of the slurry properties (mainly density) during the job execution (promoted by the use of an automatic density control mixing system if mixing while pumping or by prior mixing of the slurry).

Short term gas migration is more challenging to understand and to control. As the cement hydrates and is neither a fluid nor a solid, it loses its ability to transfer hydrostatic pressure. In this situation the annular pressure will decrease in the setting process. This is described as an annular pressure decay and poses the risk of locally dropping the hydrostatic pressure below the pore pressure. The slurry needs to be designed carefully to shorten that transition time (rapid gel strength development during cement hydration) and to control gas entry and gas migration in the cement matrix while setting (low permeability/porosity of the gelled cement, control of chemical shrinkage).

Complex models exist to evaluate the immediate and short-term risk of gas migration and should be used to design fit-for-purpose solutions.

Key parameters for slurry design are (Guillot, 1990):

- No Free fluid (separation of water from the cement/settling) as free water could generate the formation of a channel in deviated wells.
- Fluid loss control.
- Rapid set and gel strength development of the slurry.
- Low porosity / high solid volume fraction (SVF) slurry; and
- Low permeability slurry (addition of polymers, bridging agent, latex additives).

Key parameters for best practices in cementing are:

- Well conditioning; and
- Casing centralization

Key parameters for cement coverage are:

- Sufficient cement volume; and
- Obtaining a placement / post placement pressure close to the fracture pressure to maximize over balance pressure (OBP) at the end of the placement and minimize the critical gel strength period, which essentially means maintaining over balance longer during the hydration phase.

2.8 Conclusions

Many factors will affect the cement placement in a real well situation. Standards and guidelines are given to guide the engineer in the design.

Powerful fluid dynamics simulation models are available to optimise the cement placement. These tools allow the engineers to estimate and hence mitigate the risks associated with placement. These simulations can be run for a specific site and to design a fit for purpose well design.

Whilst the standards, guidelines and simulation tools available remain the same for different sites, the challenges posed at different sites, and the solutions to these challenges, will be different. In South Australia the well design in the Cooper Basin will therefore be different from that required in the Otway Basin.

Use of leading practices if adhered to can minimise this risks to the cement sheath integrity, for example:

- Ensuring communication between zones of fluids is isolated in the design of the well architecture.
- Providing, and quality assuring, cement coverage of any aquifers.
- Only performing casing tests on newly placed cement or after cement has set and gained sufficient strength, i.e. not performing casing tests on cement which has begun to set but has not developed significant strength, which can cause radial stress cracks and compromise the zonal isolation (Goodwin and Crook, 1992); and
- Understanding shrinkage phenomena at downhole conditions of temperature and pressure and potential access to pore fluids from adjacent rocks in the outer cement sheath.

Chapter 3

Integrity of wells in service conditions

Owing to the low permeability of intact cement (less than 0.1 mDarcy), if a cement is well placed as previously explored in chapter 2, the formation of micro-annuli and or cracking of the cement sheath poses the biggest risk to leakage (Lecampion et al., 2011) if connected hydraulically. Therefore, understanding and mitigating this risk is paramount.

Long term gas migration refers to the integrity of the cement sheath during the life of the well, and hence the formation of potential pathways through and around the set cement.

The long term migration of gas has received increased focus recently with more emphasis on potential environmental impacts in the oil and gas industry. Achieving the optimal long-term properties of the set cement to ensure integrity of the cement through-out the life of the well has developed rapidly over the past twenty years. There remains a lot of unknowns as comprehensive testing of mechanical properties of the cement is not typically performed (to allow reference to typical values or a database) owing to the logistical limitations, including the wide range of cement designs and the ability to cure and test specimens at the range of downhole conditions.

Several models exist and are being developed/refined to predict/assess the risk of failure of the cement sheath and the failure mode (i.e. failure in tension, in compression, formation of micro-annuli) and to better understand how to change the slurry to mitigate these risks.

It is also critical to understand all the stresses (mechanical and thermal) sustained by the cement sheath to identify realistic threats to the integrity of the well cement.

Methods to influence the set cement properties are developing fast, including:

- The possibility to increase compressive strength of the cement (higher solid volume fraction slurries, use of silica or micro-silica).
- The use of expanding cement (when anticipating micro-annuli) across hard formations only, otherwise can the cement can expand away from the casing.
- The use of flexible cement to improve set-cement flexibility (lower young modulus) to lower the risk of stress induced cement failure

In order that reliable structural analyses be performed to predict the performance of wells under in-service stresses three key questions are posed:

- What the loading scenarios that are envisaged to be encountered during the in-service lifetime of a well?
- How are materials tested at down hole conditions to obtain constitutive relationships?
- How rigorous are the modelling approaches?

These three questions are answered in the following text.

3.1 Loading scenarios

The stresses that a well is likely to be subjected to over the full duration of its in-service lifetime are crucial for predictive analyses to be performed. Identification of critical loading events such as pressure integrity testing on completion, drilling operations and stresses imparted on the well during high pressure hydraulic fracturing operations and their quantification for the given geological in-situ stress conditions is crucial in the prediction of the integrity of a cement sheath.

In order to preserve integrity, the cement sheath should resist against the stresses originated from different well completion and production procedures (Ravi et al., 2002) such as drilling, production processes (Wang and Taleghani, 2014), casing expansion and contraction (Jackson and Murphey, 1993).

3.1.1 Causes of pressure variations

Fluctuations in pressure magnitude along a well bore can happen because of the following reasons:

- Casing expansion/contraction (Goodwin and Crook, 1992).
- Completion activities, including when applicable, hydraulic fracturing.
- Loading from formation stresses such as tectonic stress, subsidence and formation creep (Zhang and Bachu, 2011)
- Change of pore pressure or temperature (Dusseault et al., 2000)
- Normal well production (Zhang and Bachu, 2011)

The condition of downhole cement is changed due to the imposed changes in pressure during the well lifetime. The changes in pressure mainly happen through four stages: well bore drilling, casing perforation, hydraulic fracturing, and production (Thiercelin et al., 1997).

The extent to which a particular casing string is subject to pressures in the production phase of a well's life is dependent upon whether production tubing is employed - i.e. whether higher casing strings feel the pressures imparted by hydraulic fracturing operations.

3.1.2 Causes of temperature variations

Fluctuations in temperature magnitude along a wellbore can occur due to the following reasons:

- Injections of hot steam (Albawi, 2013).
- Injections of cold water (Bois et al., 2009).
- Cement hydration (Neville and Brooks, 1987; Mehta and Monteiro, 2014).

Thermal stresses can result in downhole deformation. The diameter and circumference of steel casing expands due to the high temperature conditions, the resulting circumferential force generates a shear force at the interface of the cement and casing and result in cement-casing bond failure or radial fractures (Khandka, 2007).

3.2 Experimental tests

Many laboratory tests have been performed on the cement sheath to simulate the bottom-hole conditions of a wellbore and identifying the key parameters compromising of integrity of well cements. According to these experiments the mechanical properties of the cement sheath (elasticity, strength, expansion, etc.) play important roles in retaining well cement integrity (Boukhelifa et al., 2004). In this section the key parameters and their experimental determination are outlined.

Class G cement has a typical water cement ratio of 0.45 and density of 15.77 ppg or 1889.6 kg/m³ (Yuan et al., 2013). The key mechanical parameters are as follows:

- Stiffness (Young's modulus)
- Poisson's ratio (the ratio of lateral strains to a change in length of a sample of material)
- Unconfined compressive strength
- Tensile strength
- Hardening / softening of materials beyond their elastic state.

James and Boukhelifa (2008) recommended a set of measurements methods to determine the principal cement parameters (Young's modulus, Poisson's ratio, unconfined compressive strength (UCS), and tensile strength) as inputs for wellbore integrity models and they validated their approach by field evaluation at actual wells. They suggested using suitable load frame equipment with controllable load and displacement rates. Based on their results, Young's modulus and Poisson's ratio are independent of confining stress and tensile strength is 10% of the ultimate compressive strength (James and Boukhelifa, 2008).

In order to compare the static and dynamic mechanical properties of cement (Reddy et al., 2007) cured cement with different slurries under pressure of 3000 psi (20.7 MPa) and temperature of 190°F (87.8°C) for 72 hours in an autoclave and subsequently cooled at room temperature and de-pressurised slowly. According to this experiment, cement with the highest density has the highest stiffness. There is also a correlation between static and dynamic properties which states that dynamic modulus are about 1.6 times static modulus (Reddy et al., 2007).

Four different cement systems in terms of chemical additives, Young's modulus, and Poisson's ratio were examined under pressure variations (increasing and decreasing inner casing pressure by Goodwin and Crook (1992)). According to their experimental results the cement system with higher Young's modulus were more brittle and fails due pressure increases while the cement with lower Young's modulus was more ductile and remained intact.

3.2.1 Effect of curing conditions on the cement mechanical parameters

Handin (1965) examined the impacts of temperature, internal confining pressure, and pore pressure on ultimate compressive strength of oil well cements in the earliest tests found. Samples of different cement classes (class A, Incor, Unaflo, Pozmix A and Starcor) and additives were prepared all with a confining pressure of 3000 psi (20.7 MPa), but with different curing temperatures (110, 200, 320 & 350 °F or 43.2, 93.3, 160 & 176.7 °C). The majority of samples were cured for 7 days (air dried), however a series of samples were cured at 1, 3, 14 and 28 days. Uniaxial compression tests and triaxial compression tests with confining pressures of 7500 psi (51.7 MPa) and 15000 psi (103.4 MPa) were performed, the results are shown in figure 3.1 and demonstrate the increase in strength with confining pressure.

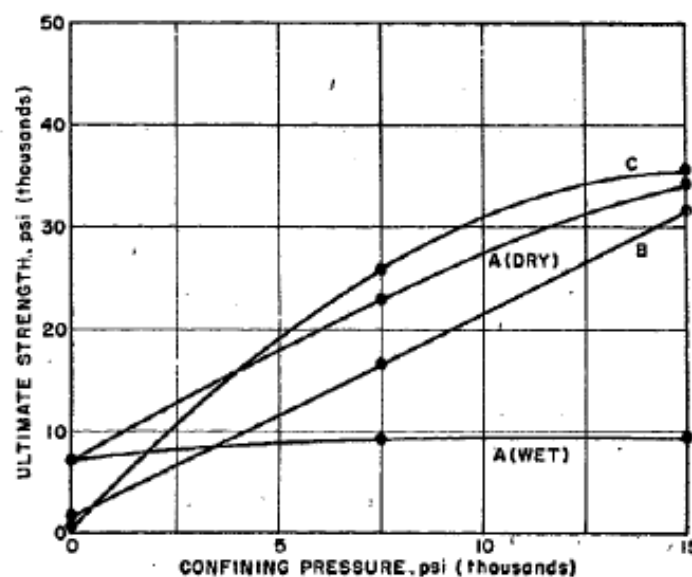


Figure 3.1: Plot of compressive strength versus confining pressure at room temperature, Handin (1965)

According to the findings of Handin (1965), even under very low effective confining pressure the conventional cement becomes very ductile as shown in figure 3.2. Additionally, he investigated the impact of temperature on the strength of cement in pressure of 15000 psi and 300 °F (148.9 °C). In one sample a 20% reduction in the strength of the cement was observed as the temperature increased from 75 °F to 300°F (Handin, 1965).

Odelson et al. (2007) investigated the effects of elevated temperature on the Young's modulus of cement paste as an indicator of mechanical damage. In their experiments, the samples at the age of 90 and 100 days were examined using displacement-controlled oscillatory bending tool, they ensured that additional microcracks were not occurring due to the applied loading. They demonstrate that the major losses in stiffness occurs predominantly when cement is exposed to temperatures in excess of 120° C. The primary mechanism for this loss of stiffness was summarised to be due to microcracking of the cement as the pore water expanded with temperature, and not through chemical changes and was seen to be independent of the mix design. The hydration

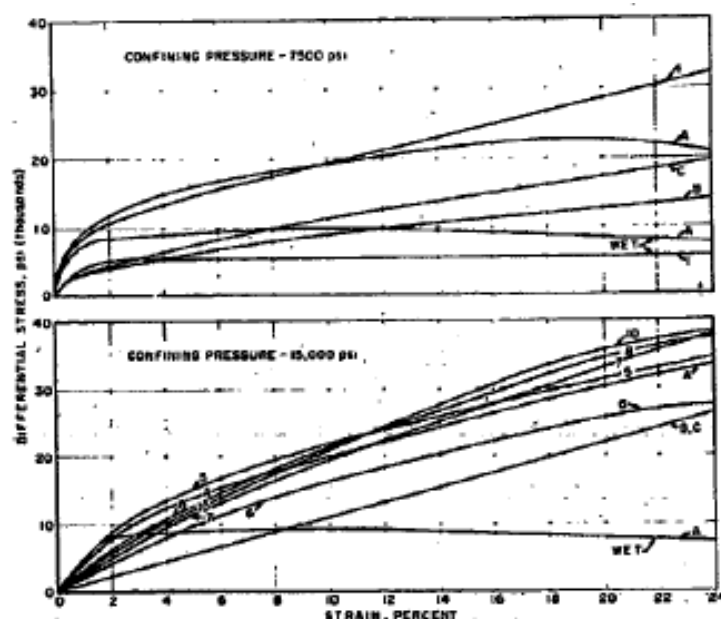


Figure 3.2: Plot of stress versus strain at room temperature, Handin (1965)

product CSH in cement (described in more detail in chapter 4) is typically reported to thermally decompose between 200 and 400°C.

Menou et al. (2006) performed experiments to investigate the temperature dependency on fracture energy (ductility in tension) of concretes and mortar. They used pre heated notched beam samples and performed three point bending tests until failure. They demonstrate that the fracture energy increased dramatically at 120 °C compared with specimens tested at 20 °C and remained relatively constant thereafter with increasing temperature (up to 400 °C). They also show reductions in the stiffness with temperature in the order of 50% at 120 °C in comparison to 20 °C.

Table 3.1 gives an overview recent of mechanical testing in the open literature. There is relatively little data published owing to the fact that cements are designed on an almost well by well basis. The results are difficult to compare owing to the variety of different mix designs, curing conditions, curing time before testing and sample sizes.

The results of Nasvi et al. (2012), who looked at the effect of curing temperature in a systematic manner are particularly interesting in revealing a strength retrograde after a curing temperature in the region of 55 °C. The results from their experiments are plotted in figure 3.4. This observation is confirmed by Makar and Luke (2011).

According to Makar and Luke (2011) the degree of hydration, and physical properties of cured cement is reliant on the curing temperature and time before exposing to high temperature in steam injection situations after setting. In geothermal wells, cement is exposed to high temperature before it sets which leads to different situations and different mechanical properties. Samples pre-cured at 35 °C for one day and then were exposed to 230 °C showed higher flexural and compressive strength compared with samples which were exposed to 230 °C immediately.

Teodoriu et al. (2012) provided a data inventory for cement class G characteristics by per-

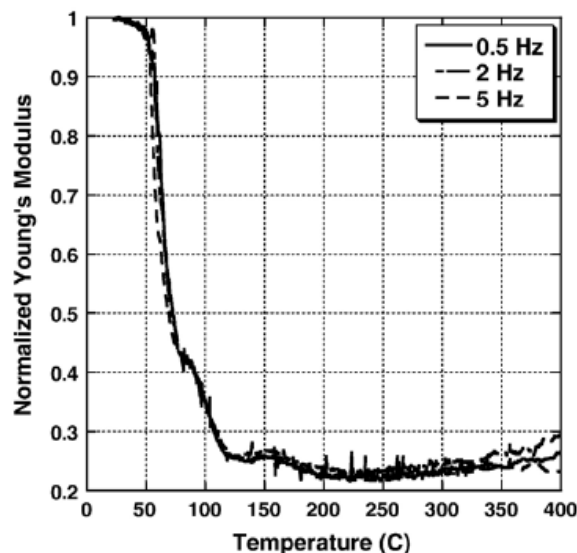


Figure 3.3: Stiffness reduction with curing temperature, Odelson et al. (2007)

forming experiments to determine and measure the mechanical properties of the cement. The experiments were performed under room condition and under elevated temperature and pressure. In order to measure and compare the compressive strength of the cement under different conditions, conventional unconfined and confined compressive tests were performed on the cubic samples under different curing conditions. The ultimate compressive stress of the cement class G cured at 65 °C was constant at 64 MPa. The compressive stress of the cement class G, cured at 100 °C and 18 MPa confining pressure, was measured as 47 MPa. The Poissons ratio was measured as 0.3 in room conditions and for the cement cured at 65 °C decreased to 0.2. However, in the third condition (100 °C and 18 MPa) the Poisson's ratio did not show any notable change. The Youngs modulus of cement cured at 65 °C was measured as 17 GPa. Yuan et al. (2013) cured cement class G in three different conditions: (1) room condition ;(2) 167 °F (75 °C) and atmospheric pressure 14.7psi (0.101 MPa); and (3) with 212 °F (100 °C) under 2610 psi (18 MPa) pressure.

3.2.2 Cyclic loading Response

Two very different regimes can be identified when examining the response of materials to cyclic loading. Vibration induced damage from a large number (typically thousands) of low amplitude loading cycles is generally represented by a Wohler or 'S-N' (stress versus number of cycles to failure) curve as shown in figure 3.5. This fatigue failure of the well cements could conceivably arise from the operation of drilling machinery.

A relatively small number of cycles can dramatically reduce the strength of a material that is subjected to high amplitude loading as shown in figure 3.6. This scenario is plausible for wells, with cyclic loading of the material possible both from changes on annulus pressure and temperature.

Yuan et al. (2013) investigated the behaviour of cements cured under different conditions subject

Table 3.1: Mechanical testing of well cements

Reference	Compressive strength (MPa)	Curing Temp. (°C)	Curing Pressure (MPa)	Curing time (days)	Sample shape and dimensions (mm)
Le Roy-Delage et al. (2000)	37	77	27	3	Cube 50.8×50.8×50.8
Le Roy-Delage et al. (2000)	39.2	114	20.7		Cube 50.8×50.8×50.8
Morris et al. (2003)	36.9	84	27	2	Cube 50.8×50.8×50.8
Guner and Ozturk (2015)	49	ambient	ambient	3	Cylinder 50×100
Nasvi et al. (2012)	27.8	23	ambient	3	Cylinder 50×100
Nasvi et al. (2012)	42.6	40	ambient	3	Cylinder 50×100
Nasvi et al. (2012)	50.7	60	ambient	3	Cylinder 50×100
Nasvi et al. (2012)	27.5	80	ambient	3	Cylinder 50×100
Teodoriu et al. (2013)	36	65		1	Cube 50.8×50.8×50.8
Teodoriu et al. (2013)	48	ambient	ambient	3	Cube 50.8×50.8×50.8
Teodoriu et al. (2013)	64	65		14	Cube 50.8×50.8×50.8
Teodoriu et al. (2013)	47	100	18	14	Cube 50.8×50.8×50.8
Yuan et al. (2013)	55.7	ambient	ambient	14	Cyl. 110×160 [†]
Yuan et al. (2013)	60.8	75	ambient	14	Cyl. 110×160 [†]
Yuan et al. (2013)	56.7	100	18	14	Cyl. 110×160 [†]
Labibzadeh et al. (2010)	10.95	ambient	ambient	1	Cube 50.8×50.8×50.8
Labibzadeh et al. (2010)	16.55	ambient	ambient	2	Cube 50.8×50.8×50.8
Labibzadeh et al. (2010)	14.24	38	2.8	2	Cube 50.8×50.8×50.8
Labibzadeh et al. (2010)	12.72	68	17.2	2	Cube 50.8×50.8×50.8
Labibzadeh et al. (2010)	18.82	82	41.4	2	Cube 50.8×50.8×50.8
Labibzadeh et al. (2010)	16.4	121	51.7	2	Cube 50.8×50.8×50.8
Labibzadeh et al. (2010)	4.59	149	51.7	2	Cube 50.8×50.8×50.8

[†]the Yuan et al. (2013) samples were hollow cylinders with an inner radius $r_i = 40$ mm.

to low cycle fatigue including the effects of temperature and confining pressure. Figure 3.7 shows (a) the sample tubing and moulds, (b) the cast dimension of the steel tubing and cement, (c) the applied loading and a photograph and a failed sample. Results from the tests are shown in table 3.2, showing the number of cycles to failure is dramatically reduced with the amplitude of the loading.

Table 3.2: Low cycle - high amplitude fatigue test results Yuan et al. (2013)

Load (lbf)	Cycles
55115	15
55115	17
55115	14
77162	4
77162	5
77162	4

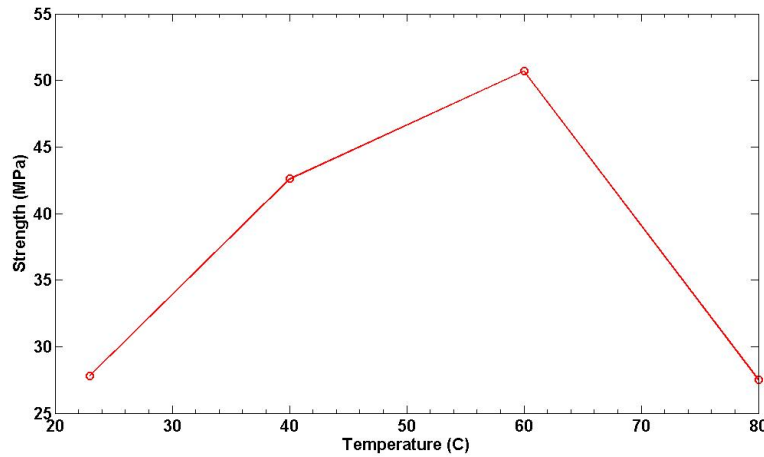


Figure 3.4: Effect of curing temperature on cement strength, Nasvi et al. (2012)

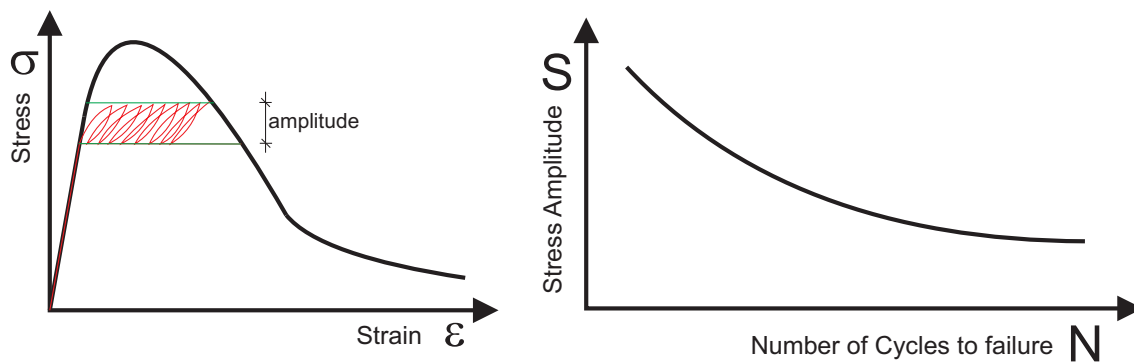


Figure 3.5: High Cycle - Low Amplitude Fatigue

In order to investigate the integrity of the cement sheath class H under cyclic loading Shadravan et al. (2014) introduced new high pressure and high temperature (HPHT) experiments set up with the aim of cement integrity evaluation under cyclic loading and finding fatigue failure cycles inside the cement sheath at elevated pressure and temperature. After curing the cement (class H + 35 % silica, to avoid strength retrogression at elevated temperatures) for 15 hours, with a confining pressure of 15000 psi (103.4 MPa) and temperature of 330 °F (165.6 °C). A differential pressure (1000, 2000 & 5000 psi) was subsequently applied cyclically on the casing as shown in figure 3.8. The reduced number of cycles to failure with pressure differential is shown in figure 3.8, radial cracks were observed to be the primary type of failure under cyclic loading.

The effects of cyclic temperature loading is a very recent development in the study of cement sheath integrity. Andrade et al. (2015) describe a one quarter scale test apparatus they have developed that is capable of inducing thermal cycles in the central annulus and subsequently measure the formation of cracks and micro-annuli using three dimensional computed tomography (CT) scanning of the samples. Figure 3.9, shows computed tomography scans capturing initial debonding and cracks in the cement and subsequent growth after temperature cycling. The results shown are for temperature cycles raised from 15 °C to 130 °C at a rate of 1.5

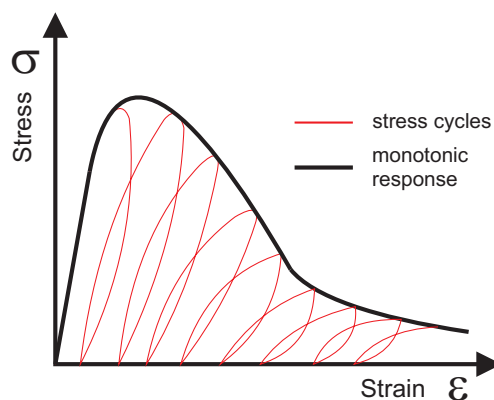


Figure 3.6: Low cycle - High Amplitude Fatigue

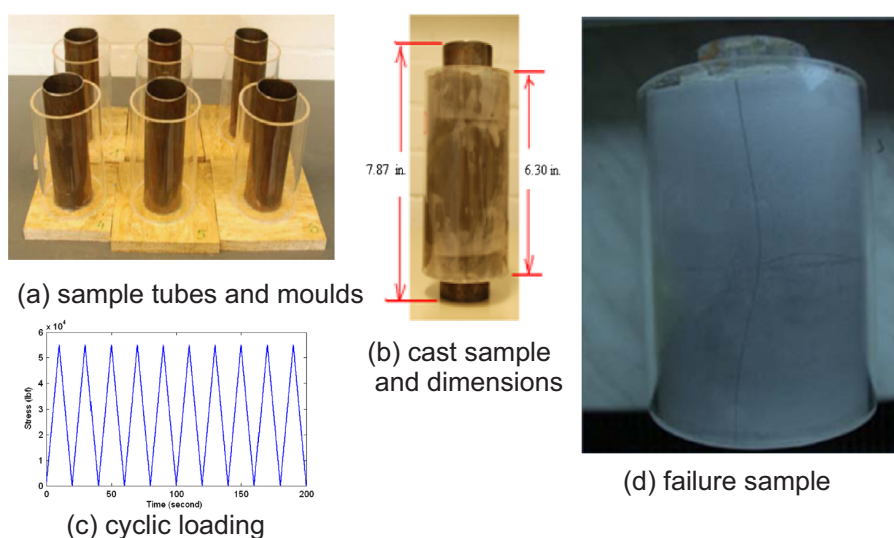


Figure 3.7: Low cycle - High Amplitude Fatigue testing Yuan et al. (2013)

°C/min, held constant for 4 hours, cooled to -1 °C at a rate of 1.5 °C/min and again held for 4 hours before raising back up to 130 °C.

3.3 Numerical modelling

In order to assess the integrity of cement sheaths, numerical simulations of the response of the wellbore to the various pressurising and temperature cycles that a well will be subject to over its service life will become increasingly common practice in the oil and gas industry. A short overview of current work follows.

Nabipour (2010) performed finite element modelling of the cement sheath using linear elastic materials with no consideration of debonding between the cement and casing. However, the parameter study (internal pressure, differential horizontal stress, casing eccentricity), demonstrates that the differential horizontal (formation) stresses are more significant than internal

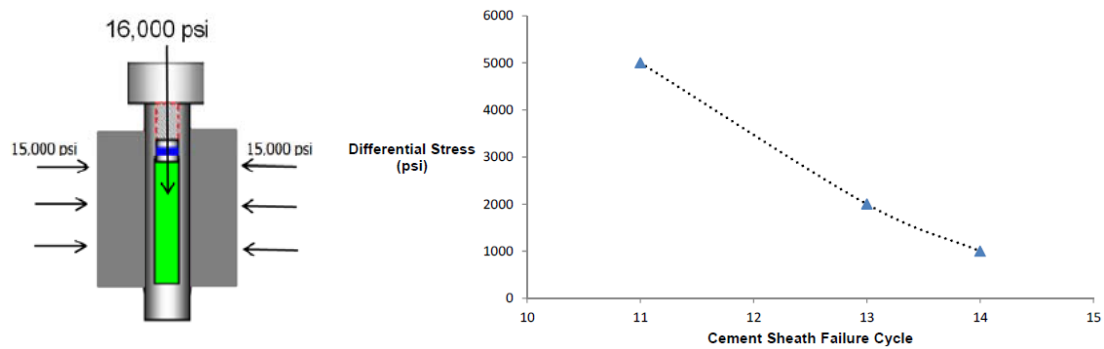


Figure 3.8: HPHT cyclic experimental set up and results, Shadravan et al. (2014)

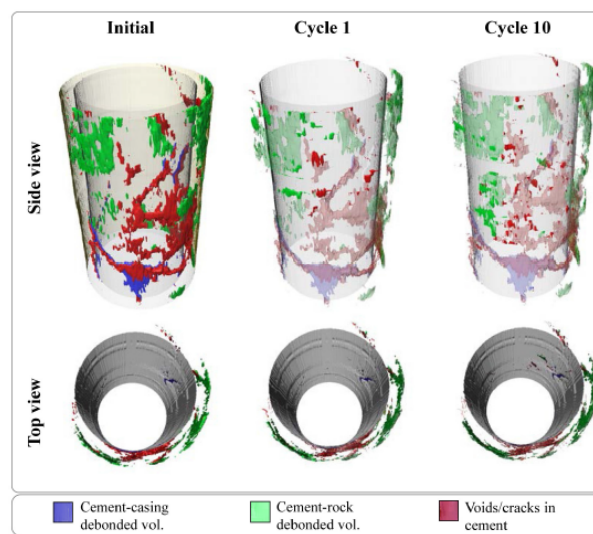


Figure 3.9: Results of cyclic thermal loading experiments, Andrade et al. (2015)

casing pressures and their interaction with the casing eccentricity will govern where the highest stresses occur.

Lecampion et al. (2011) studied the modelling of interface debonding (formation of microannulus) between casing / cement or cement / formation, in the context of CO₂ storage. They model the coupled micro-annular flow with the (elastic) opening of the micro-annulus under fluid pressure. Their primary concern was with CO₂ injector wells, but they postulate that this fluid driven debonding may also be of concern in hydraulic fracturing operations.

Bosma et al. (1999) performed finite element modelling of well sealant integrity, their model included heat transfer modelling and demonstrated the need for coupling of temperature and stresses.

Bois et al. (2013) discuss the mechanical mechanisms that could lead to loss of cement-sheath integrity before and during CO₂ sequestration. They strongly advocate the treatment of the cement sheath as a porous medium with consideration of temperature, as opposed to a one phase solid subject to external forces. This approach then leads itself to the simulation of numerous

mechanical events (mud pressure variations, formation stress variations, temperature variations in the wellbore, pore pressure variations in the cement, dynamic loading of the wellbore and cement property changes with time).

The modelling of cyclic loading failure mechanisms is particularly problematic. Lifetime analysis of High cycle - low amplitude fatigue is typically assessed using a 'Wohler' curve, but is limited to constant amplitude loading. Low cycle - High amplitude fatigue modelling is also problematic with current commercially available models, capturing loading-unloading hysteresis and therefore accumulative damage / plasticity when loading does not reach the current yield stress is not well accommodated for.

3.4 Conclusions

The following factors are crucial to the analysis of the integrity of well cements:

- the different cement compositions employed.
- the effect of different curing conditions on the properties of the set cement.
- the dependence of the material properties (strength, permeability, heat conductance etc.) with temperature.

Future work in predicting the integrity of well cements over the whole service life will require accurate laboratory techniques to quantify the key material parameters required in a given analysis. The accuracy of these parameters will be determined by how closely the laboratory conditions can mimic the real world downhole conditions.

3.4.1 Mechanical testing

It is important to consider the whole failure surface (different stress states), not just the compressive response of API standard 2 inch cubes. The response of cementitious materials is both vastly different under compression than it is in tension, with the uniaxial tensile strength being approximately 10% of the uniaxial compressive strength. Furthermore, the strength of the material is pressure sensitive, i.e. the strength of the material appears higher with applied pressure. Figure 3.10, shows the permissible stress state that a material is able to withstand before cracking or plastic deformation, τ is the shear stress and P is the pressure.

The reliability of the use of 2 inch cubes for the determination of the strength of well cements is questionable Garnier et al. (2007). In the field of structural engineering, compressive strength is also the most common measure of the quality of concrete. It has long been recognised in the field that the compressive strength of cylinders with an aspect ratio (length:diameter) of 2:1, gives a strength in the region of 70 - 90% of that measured in cubes (Kong and Evans, 2001). This difference is due to the confining effect of platten restraint that can make specimens appear stronger as it is not the uniaxial response, but rather a multiaxial response that is been measured.

In addition to the admissible stress state the deformation behaviour of a material is important to the behaviour of a well. Figure 3.11 shows two typical stress-strain plots for materials. The

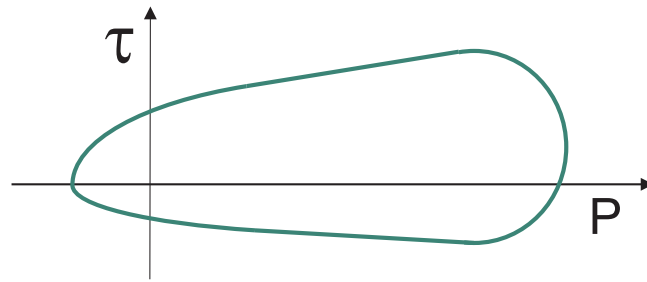


Figure 3.10: Range of permissible elastic stress states

red line shows a very stiff material in its elastic range and brittle beyond the peak stress, whilst the blue line shows a less stiff material which is far more ductile beyond the peak stress.

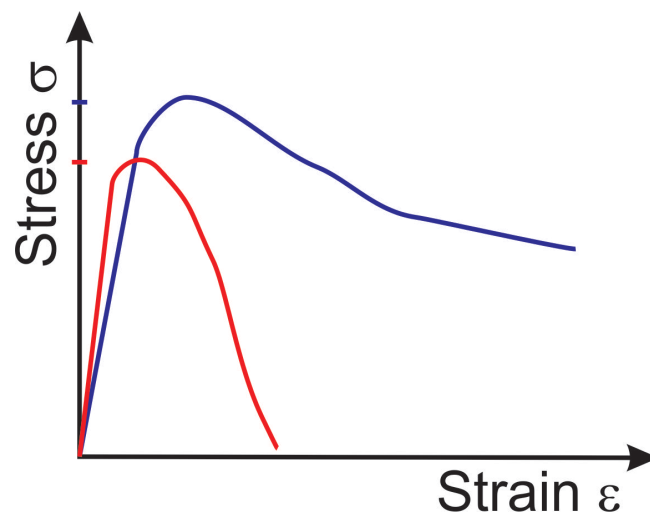


Figure 3.11: Deformation response of well cements

The majority of testing on well cements found in the open literature has been performed on Class G or Class H cements. For comprehensive structural integrity analyses to be performed, material property data is required for cement slurry blends used in practice, for example on lead cements (class G blended with bentonite) and high temperature blends (addition of silica fume).

The effect of loading rates can be significant in measuring material properties. It is therefore important to load sufficiently slowly to obtain static strength parameters. Strain rate dependant material parameters, by extension, may become important if the loading is significantly fast, but static strength parameters can be considered to be conservative.

Influence of Cement Curing Regimes

A given cement will possess different mechanical properties owing to the curing regime. This will in turn have different properties at the prevailing temperature and pressure conditions which cannot be assumed to be constant over the lifetime of the well.

Influence of Temperature on Mechanical Properties

In designing experimental test procedures for measuring the strength characteristics of a given cement it is important to model the full life of the cement. It has been demonstrated that loading then subsequently heating concrete specimens gives a different response than heating before loading (Petkovski et al., 2006). Therefore, it is imperative to replicate the correct in-situ temperature and pressure conditions during both curing and mechanical testing.

3.4.2 Numerical modelling

Structural analysis software packages are maturely developed technology that are already employed in the oil and gas sector for modelling geological stresses. There is the possibility to make use of this technology more widely in the integrity analysis of wells subject to the loading scenarios they will be subject to over their lifetime.

Bois et al. (2013) and Bosma et al. (1999) show that multi-physics modelling of solids is feasible and necessary for modelling the response of cements. Fluid-structure interaction has also been used to demonstrate the opening of microannuli (Lecampion et al., 2011) which could be extended to the creation of microannuli.

3.4.3 Loading and initial conditions quantification

The identification and quantification of temperature and pressure loading that a well will be subjected to over its lifetime will be an important part of future work in the determination of design guides or the building of reliable numerical models for the structural integrity of wells. Likewise the initial conditions (formation stresses, pore pressures etc) that a well is subjected to are vital in determining the stress range that a well may perform its role of achieving zonal isolation before cracking and / or the formation of microannuli could possibly compromise this objective.

Chapter 4

Long term integrity of wells

A study by Davies et al. (2014) estimated that there there has been in excess of 4 million onshore hydrocarbon wells drilled globally. Included in this dataset were 9903 wells that had been drilled in Australia (using data obtained from Geoscience Australia in 2013). The long term integrity of any *abandoned* (wells that have been decommissioned, see the following section), and potentially *orphaned* (where the company that operated a well is no longer responsible for it), wells is therefore of concern in assessing whether they pose a long term environmental hazard.

For fugitive emissions to occur both a leakage pathway and a pressure gradient need to exist, as discussed in chapter 1. In this chapter we will concentrate solely on the potential for well cements to degrade over time and thus contribute to the formation of a potential leakage pathway. The durability of the well cements in the long term, subject to the specific downhole chemical environment, temperature and pressure conditions is of focus. To this end the key questions to be addressed are:

- How are wells decommissioned at the end their service life?
- What are the chemical composition of fluids (CO₂, formation fluids, reservoir gases) that well cements are likely to come into contact with?
- How does the mix design of the cement affect its durability?
- What testing has been reported in the literature?
- How can accelerated ageing tests be extrapolated or applied to the long term (hundreds of years).
- What modelling tools are available (assumptions, limitations)?

4.1 Well decommissioning

At the end of a wells service lifetime a well is decommissioned. In the oil and gas industry this process is called *Plug and Abandonment* and is referred to in the literature as PnA or P&A.

This terminology is a legacy of less environmentally enlightened eras, but remains de rigeur in the industry.

The purpose of a plug and abandonment program is to ensure long-term isolation by replicating the natural barriers between the geological intervals. Although, cement plugs are generally placed for that purpose, they can be combined with mechanical wellbore barrier elements (downhole tools such as bridge plug or cement retainer), which act as sealing devices. In some cases, abandonment may require the need to *squeeze cement* (targeted remediation cementing) prior to setting a cement plug (i.e. filling of perforations in the well to access the hydrocarbons of perforations).

The decision to permanently abandon a well can occur at different stages:

- While drilling a well: if the hydrocarbon interval is insufficient for a well to be economical (dry hole), it will be abandoned instead of being put on production. In that case, the production casing will not be run and a series of cement plugs will be set in the open hole and inside the previous casing to restore zonal isolation.
- During/at the end of life of a production well when production becomes insufficient. In that case, each perforated interval inside the production will be abandoned (cement squeeze and plug). This can happen in several stages where depleted intervals will be squeezed off and plugged while non-depleted zones will still be producing.

Note: if annular-casing-pressure exists, it must be remedied to prior to final abandonment.

For a cement plug to be considered a barrier, it needs to be verified as such. There are several methods to verify a cement plug: tagging (and applying weight), positive pressure test and/or negative pressure test (an inflow test where the column of fluids above the plug is lightened to create an underbalance / formation fluid of the zone isolated by the plug). These methods should be applied after recommended waiting on cement (WOC) time to allow the cement to develop sufficient compressive strength / shear bond first.

4.1.1 Plug placement

The American Petroleum Institute (API Standard 65-Part 2, 2010) gives advice the design of a plug cementing job. When setting a cement plug, a small volume of slurry is pumped through a drill pipe placed at a specific depth and balanced across an interval, the drill pipe is then pulled out of the cement and the slurry is left to set.

Besides mud removal, there are specific challenges associated with that placement process. In a primary cement job (casing cement job), the use of wiper plugs ahead and behind the slurry prevent in-pipe contamination (the slurry is mechanically isolated from the other fluids inside the casing). While pumping a cement plug through a drill pipe, the slurry is in contact with the other fluids and contamination can occur at the interfaces (especially inside the drill-pipe, under the effect of gravity). Contamination can also be promoted by the use of an open-ended drill-pipe versus the use of a diverter tool (jetting effect causing mixing with the wellbore fluids as the slurry exits the DP).

The effect of contamination will be even more detrimental if the slurry volume is small and if the setting depth is deep (longer travel distance). Contamination could severely alter the

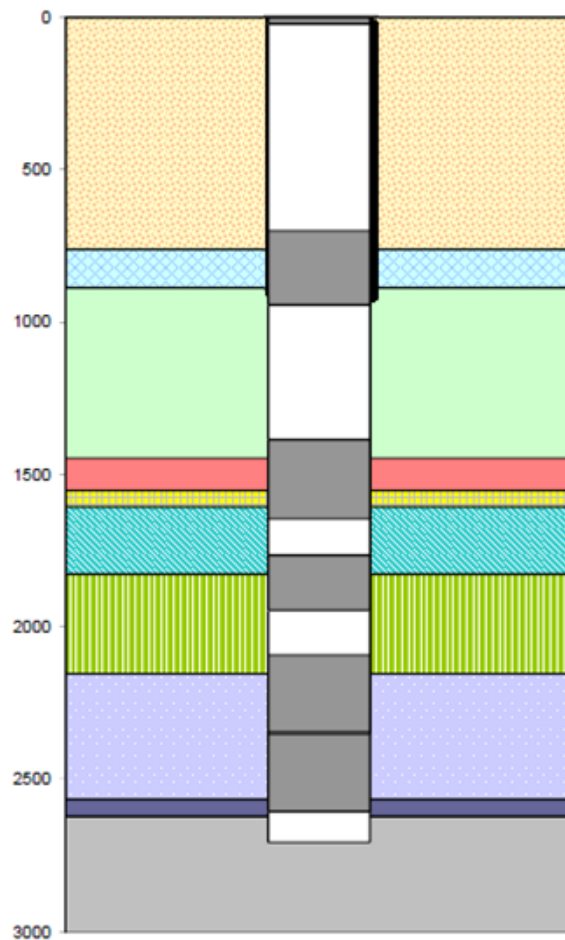


Figure 4.1: Plug placement

Figure 4.2: Plug placement - fluid mixing risk

slurry and set-cement properties and lead to plug failure due to insufficient strength and / or insufficient cement coverage. Hence the importance to verify the plug after placement. There are simulation models to assess that risk and help optimize the plug placement.

That risk can be mitigated by using a mechanical separator inside the drillpipe (foam balls, wiper darts combined with dart catchers), by increasing the volume of slurry, modifying the fluids design and / or increasing the volume of spacer ahead / behind. Contamination can also happen while pulling the drillpipe out of the balanced cement plug (it is recommended to use a stinger for the plug placement) or if the plug is over-displaced.

A cement plug placement may suffer from poor placement if the base is unstable. With gravity, the slurry will have a tendency to fall through the fluid below if the cement density is greater than the fluid in which it is being set, this slumping can be more pronounced with pipe deviation due to fluid swapping. It is therefore recommended to either place the cement plug on a solid

base (on bottom of hole, on top of a hardened cement plug or a mechanical plug), or on top of a viscous pill. There are also specific tools to mitigate this risk.

4.2 Plug design

In addition to the general slurry design characteristics, specific properties are required for abandonment cement plugs such as: rapid compressive strength development, low permeability of the set cement, adequate fluid-loss control if set in open hole (or if squeezed) and no sedimentation. To preserve the integrity of the cement plug, it is also crucial to have adequate bonding with both the casing and the formation (sufficient shear stress of the bond), to avoid shrinkage of the set cement plug (it is possible to use an expanding agent if appropriate) and to have long term durability to chemical attack (Marca, 1990).

4.3 Chemical composition of formation fluids

Zivica et al. (2012) provide a literature review on acid attack of geothermal cements, where the acidity of the formation waters, coupled with high temperatures and pressures can have a detrimental effect on the durability of cement materials. The rate of deterioration were surmised to be affected by the following factors, with respect to the solution aggressiveness:

- acid kind
- solution concentration
- contact conditions
- ambient temperature rise
- environment pressure rise
- temperature and pressure common effect; and
- combinations of the above factors that can increase the aggressiveness of the solution.

4.4 Cement composition

Zivica et al. (2012) summarise the factors in cement composition to resist acidic attack:

- cement type
- cement content
- water-cement ratio
- curing conditions; and
- pore structure

The composition of well cements is governed by American Petroleum Institute specification (API specification 10A, 2002), newly incorporated as a ISO specification (ISO10426-1, 2009). Eight classes of cement are specified (A-H) with three grades pertaining to sulphate resistance; ordinary (O), moderate (MSR) and high (HSR). The focus in this study is on class G well

cements, as the use of lower classes is almost non-existent in current Australian practice. However, it should be noted that some legacy abandoned wells may have been constructed from lower grade cements.

4.4.1 Cement ingredients

Early Gypsum and lime cements were *nonhydraulic* (unstable in water), the ancient Greeks and Romans created *hydraulic* cements with the addition of *pozzolanic* materials that react with lime (Mehta and Monteiro, 2014).

Portland cement does not require the pozzolanic material to form water resistant properties. It is a mixture mainly comprising of lime, silica, alumina and iron oxide mixed together to form complex products formed in a kiln and subsequently cooled to form *clinker* and mixed with gypsum (CaSO_4) to prevent flash setting (Neville and Brooks, 1987). Common sources of calcium are limestones and chalk, but clays, which contain alumina (Al_2O_3) and iron oxide (Fe_2O_3), or dolomite ($\text{CaCO}_3 \cdot \text{MgCO}_3$) are usually present as impurities. Clays and shales are added as an additional source of silica (Mehta and Monteiro, 2014). The presence of aluminium, iron and magnesium and alkalis help the formation of calcium silicates at lower temperatures.

The reaction of clay and limestone in the cement kiln, leads to the creation of the four main compounds that comprise the clinker are shown in table 4.1 (Neville and Brooks, 1987; Hewlett, 1998).

Table 4.1: Cement compounds Neville and Brooks (1987)

Compound	Composition	Abbreviation
Tricalcium silicate	3 $\text{CaO} \cdot \text{SiO}_2$	C_3S
Dicalcium silicate	2 $\text{CaO} \cdot \text{SiO}_2$	C_2S
Tricalcium aluminate	3 $\text{CaO} \cdot \text{Al}_2\text{O}_3$	C_3A
Tetracalcium aluminoferrite	4 $\text{CaO} \cdot \text{Al}_2\text{O}_3 \cdot \text{Fe}_2\text{O}_3$	C_4AF

The final stage of cement manufacture is the pulverising of the clinker in a ball mill and the addition of gypsum to control early setting. During the manufacturing process the chemical compound composition is subject to close monitoring and control. The final clinker is quantitatively analysed using photomicrography and X-ray diffraction.

In Australia the largest provider of well cements is Adelaide Brighton Cement Ltd, their primary product is AUSTWELL Class G (High Sulphate Resisting) cement (Adelaide Brighton Cement Ltd, 2013), their product safety data sheet lists the following ingredients:

Ingredient	Formula	Concentration
Portland cement clinker	not available	< 97 %
Gypsum	$\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$	3 - 8 %
Limestone	CaCO_3	0 - 5 %
Chromium	Cr^{6+}	< 20 ppm
Quartz	SiO_2	< 1 %

4.4.2 Cement hydration products

The cement powder is mixed with water in very controlled ratios which then chemically reacts to form hardened cement paste. The water to cement ratio (W/C) has a very strong influence upon the final set mechanics properties of the cement.

The compounds C_3S and C_2S are the most important for the strength of the final set cement. C_4AF represents a small quantity in the composition, but reacts with gypsum and may accelerate the hydration process. C_3A contributes little to overall strength of set cement, but does contribute in the early stages of hydration (chemical reaction of cement powder with water), therefore retarders are used to slow the setting time. This compound particularly susceptible to sulphate attack in set cement, for this reason C_3A content is limited in API classes of cements.

The product of C_3S and C_2S and water is $C_3S_2H_3$ with some of the lime $CA(OH_2)$ content separating out in the process. $C_3S_2H_3$ is abbreviated to C-S-H and is a micro-crystalline hydrate that is the firm, hard mass. A cement containing a high proportion of C_2S would be expected to be more durable to acidic and sulphate environments, in comparison to a cement with a high proportion of C_3S .

4.4.3 Cement additives

There exist a large number of cement additives used in well cementing, however many of these additives can be grouped by their major function (Smith, 1987):

- Accelerators, for increasing the hydration process and the development of strength.
- Retarders to slow the hydration process to keep the cement slurry workable (fluid like state) for longer.
- Lightweight additives, to reduce the weight and hence hydrostatic pressure.
- Heavyweight additives, to increase the weight and hence hydrostatic pressure.
- Lost circulation control agents.
- Filtration control agents.
- Friction reducers, to control the dynamic fluid pressure. In structural applications these are commonly called plasticisers and are used to enhance the workability.
- Speciality materials.

In addition to the additives identified above, the ambient temperature in wellbores can lead to *strength retrogression*, particularly in temperatures above 110°C. the CaO / SiO_2 ratio of the cement hydration product is lowered to below 1.3 through the addition of silica flour (Mehta and Monteiro, 2014).

4.5 Cement degradation mechanisms

An overview of the chemical deterioration mechanisms in concrete, and hence cements, is given in figure 4.3.

Some of the most well known and high profile degradation mechanisms of concrete structures have occurred due to “Reactions involving formation of expansive products” deterioration mech-

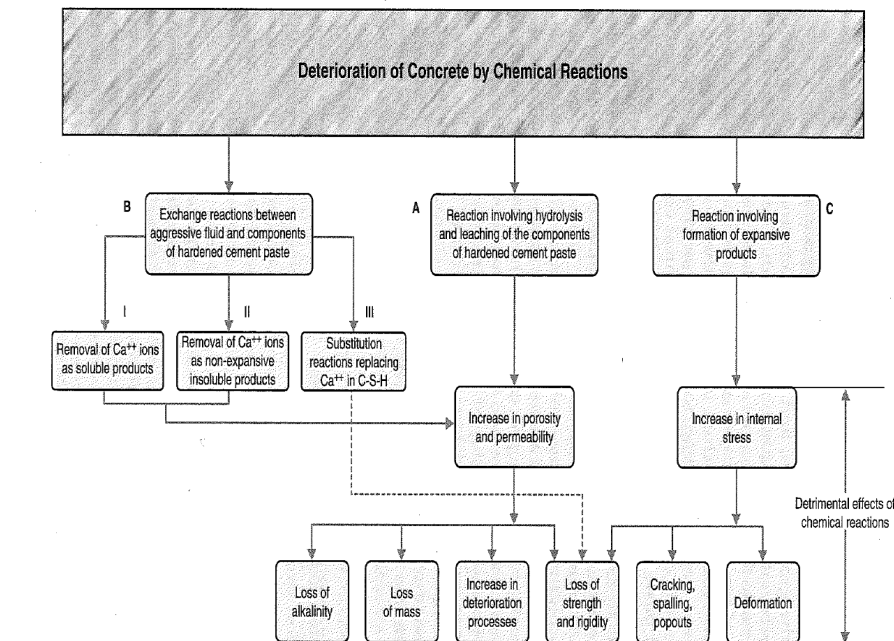
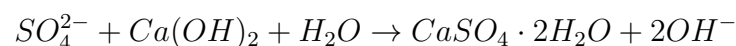


Figure 5-15 Types of chemical reactions responsible for concrete deterioration. A: soft-water attack on calcium hydroxide and C-S-H present in hydrated portland cements; B (I): acidic solution forming soluble calcium compounds such as calcium chloride, calcium sulfate, calcium acetate, or calcium bicarbonate; B (II): solutions of oxalic acid and its salts, forming calcium oxalate; B(III): long-term seawater attack weakening the C-S-H by substitution of Mg^{2+} for Ca^{2+} ; C: sulfate attack forming ettringite and gypsum, alkali-aggregate attack, corrosion of steel in concrete, hydration of crystalline MgO and CaO . (From Mehta, P.K., and B.C. Gerwick, Jr., *Concr. Int.*, Vol. 4, pp. 45-51, 1982.)

Figure 4.3: Deterioration of concrete by chemical reactions, Mehta and Monteiro (2014)

anism in figure 4.3. The spalling of concrete, particularly observed in marine environments, is due to chloride in sea salts causing corrosion of reinforcement bars. Chemical reactions with some aggregates in concrete have led to the expansion and damage of concrete due to a process known as Alkali-Silica-Reaction (ASR). These degradation mechanisms are not encountered in well cements due to the absence of reinforcing bars and aggregates in the cement slurries used in well construction.

The chemical interaction of the cement with formation waters could lead to potential degradation of the cement. Sulfates are commonly found in formation waters and can react with calcium hydroxide in cement to form gypsum (Bensted, 1998):



the gypsum then reacts with hydration products in the set cement to form *ettringite*. The products of these reactions (gypsum and ettringite) take up greater volume. Sulfate resistance of cement is increased through the replacement of $3CaO \cdot Al_2O_3$ (C_3A) with ferrite (Bensted, 1998).

Exposure of well cement to carbon dioxide CO_2 , can lead to carbonation. This process may occur due to exposure to moist air (Bensted, 1998) and has received recent attention due to the use of CO_2 for enhanced oil recovery and investigations into the feasibility of carbon storage.

4.6 Experimental testing on cement degradation

A number of researchers have performed degradation tests on oil well cements. An upturn in interest in recent years has occurred with the examination of the use of carbon capture and storage, with examination of potential leakage of the CO₂ and potential degradation of wells in contact with CO₂ saturated brine.

Lécolier et al. (2007) performed ageing experiments on API class G well cement at 80 °C and 7 MPa confining pressure in brine, they performed characterisation tests of the cured material (mercury intrusion porosimetry MIP and X-ray diffraction XRD) and investigated the ageing rate with replacement versus non-replacement of water. Duguid (2009) performed CO₂ degradation experiments to calculate the time to degrade 25 mm of cement, temperatures of 20 °C and 50 °C were used, with a leaching solution of CO₂-saturated 0.5 M NaCl solution saturated with SiO₂. The cement was LaFarge class H sulfate resistant cement W/C = 0.38, cast in sandstone cylinders.

The mutually coupled effects of chemical and mechanical effects on degradation have been recognised by Ozyurtkan and Radonjic (2014), who sought to test the effects that fractures in cements, and thus higher effective permeability, has on the deterioration under chemical action. They tested API class H cement W/C = 0.38 cured at room temperature in water (pH 13), with two halves glued to create an artificial fracture. Distilled water with NaCl and KCl salts at concentrations 0.3455 M and 0.0046 M respectively, equilibrated with CO₂, 14.7 psi / 0.1 MPa 21 °C, was used in flow through experiments with a flow rate of 2 ml/min for 100 days. A confining stress of 4.14 MPa was applied to the specimens. The deterioration was measured with the use of material characterisation testing (Helical CT, microCT, XRD, MIP). Similarly the coupled degradation effects were explored by Bois et al. (2013) who performed triaxial tests on class G portland cement in contact with CO₂. The samples were prepared under 8 MPa confining pressure 90°C and a temperature of 140°C. They performed carbonation tests and coupled chemo-mechanical tests, their results also show material characterisation (X-ray tomography, scanning electron microscopy SEM, XRD, thermal gravimetric analysis TGA) and mechanical response to isotropic compression and creep. The results were followed with a discussion on the need for an integrated approach to integrity.

Kjellsen et al. (1990) examined the effects of curing temperature on pore structure of cement paste hydrated at different range of temperatures by using mercury intrusion porosimetry. They discovered that the pore structure of hydrated cement paste is highly affected by curing temperature. Cement paste hydrated at higher temperatures have higher porosities. This has a direct effect on the cement permeability. Therefore, cements which cured in higher temperature have lower durability.

The extrapolation of results from laboratory tests, that through necessity need to be able to be performed over relatively short periods (< 1 year), is problematic in the long term prediction of the potential for chemical deterioration of well cements. Numerous techniques may be performed in a laboratory situation to accelerate any ageing processes, but how reliable the results are is questionable. Heating will speed up reaction rates, but the transport of fluids in the pore structure of the cement will remain constant, conversely degradation can be worse in laboratory samples where surface:volume ratios can be much higher than experienced in the field (Bensted, 1998). Obtaining field data is troublesome as the integrity of a well where cores are taken will inevitably be compromised. However, Carey et al. (2007) were able to obtain

field core samples of well cements and shale caprock after 30 years exposure to a CO₂ flooding operation.

4.7 Numerical modelling of cement degradation

Owing to the difficulty in performing experimental degradation experiments, in terms of duration of experiments, the number of potential combinations of pore water and cement compositions, temperature and pressure variations; the use of numerical modelling tool to predict the long term fate of cements is crucial.

There exist numerous commercially available numerical tools that can be applied to the prediction of cement life time modelling. One such tool is ToughReact (Xu et al., 2004) which couple pore water movement, heat transfer and geochemical modelling and has been applied to predict the alteration of wellbore cement in the context of CO₂ storage (Gherardi et al., 2012; Geloni et al., 2011).

Deremble et al. (2011) has also investigated the chemical reactions of CO₂ with cement performing numerical simulation and investigating the general stability criterion of a given pathway. Huet et al. (2010) also applied reactive transport modelling of cement in CO₂, with details of numerical model employed and numerical experiments that were conducted to validate their approach.

4.8 Conclusions

When investigating the long term integrity of wells there arises the need to define when a well is no longer fit for purpose? Criteria defining when a well would require remedial work will need to be defined, for example:

- strength based criterion - no longer able to withstand imposed stresses
- permeability based criterion - no longer able to maintain zonal isolation

Experimental testing of cement degradation needs to be performed in an accelerated manner to produce results in a reasonable timeframe. This can be achieved by the use of elevated chemical concentration levels or temperatures, pore flow would be difficult to accelerate (but achievable in a centrifuge). However as the physics and chemistry is inherently coupled, how accelerated ageing tests can be performed in a reliable manner is debatable. Experimental modelling can however be used for the validation of numerical models

Numerical models exist that could potentially describe chemical degradation, but owing to the problems with validating their performance over long time scales these methods should only be seen as state of the art forecasting and reliable predictions.

Most degradation tests found in the open literature were performed on ‘pure’ class G cements. Experimental results regarding the long term performance of lead cements (class G blended with bentonite) and high temperature blends (addition of silica fume) are required.

A database of formation fluid compositions that a cement sheath could come into contact with would be required. The chemistry of the formation waters could then be used as inputs to the numerical simulations tool available to perform forecasting.

Chapter 5

Conclusions & Recommendations

An exhaustive literature review of well cements and cementing practices would be an almost impossible task. In depth treatments of the subject can be found in the books by Smith (1987) and Nelson (1990) (and its updated 2nd edition Nelson and Guillot (2006), weighing in at 773 pages in length). This review has therefore focused on identifying potential problems that may be encountered and where future research could address to raise the threshold of what would be considered As Low As Reasonably Practicable measures that could be undertaken reduce any risk.

5.1 Cement placement

The placement of well cements is a relatively mature technology owing to its importance to the success of a well to produce. The technology has advanced considerably the 1820s when wells were open drilled and left uncemented and continues to advance as the challenges and objectives of a well change with time. Creating zonal isolation between fluid bearing geological zones encountered with depth, and not merely hydrocarbon bearing layers, has become a crucial objective in well design and the regulations governing their construction in South Australia. Not all fluid bearing zones need to be zonally isolated, indeed some zones are in natural communication, and require assessing on a well-by-well basis.

Well design and quality assurance is overseen by the South Australian Governments Department of State Development to ensure that any newly constructed wells conform to the regulations and international best practice. Ongoing projects are identifying existing wells that require repair in order to meet modern standard of construction and eliminate the risk of leakage.

5.1.1 Recommendations

Some simple best practices if adhered to can minimise this risks to the cement sheath integrity, for example:

- Ensuring communication between zones of fluids is isolated in the design of the well architecture.

- Providing, and quality assuring, cement coverage of any aquifers.
- Only performing casing tests on newly placed cement or after cement has set and gained sufficient strength, i.e. not performed on cement which has begun to set but has not developed significant strength, which can cause radial stress cracks and compromise the zonal isolation (Goodwin and Crook, 1992).
- Understanding shrinkage phenomena at downhole conditions of temperature and pressure and potential access to pore fluids from adjacent rocks in the outer cement sheath.

5.2 Integrity during service life

Examination of the threats to well cement integrity during its operational lifetime is an emerging field. Identification of the of the loading (pressures and temperatures) that different segments of a well might endure will be crucial in identifying if any operations could lead to compromising a wells integrity and inform mitigating measures that could be performed.

In considering the components of a wells cement sheaths response to loading, an understanding of the material properties of the cements is of paramount importance. The material properties will be affected by:

- the temperature and pressure at which the cement sets; and
- the temperature and pressure at which the cement is subject to loading.

There is some data in the open literature available regarding the properties of ‘pure’ class G and H cements. In practice, the cements are blended with many additives, the most frequently used being to create lower density lead cements and additives used to overcome problems at elevated temperatures. Data on the material properties of cement blends are difficult to find in the open literature.

5.2.1 Recommendations

It is recommended that:

- How the cement sheath strength is incorporated in existing well design procedures is clarified.
- An inventory of loading scenarios is compiled (possibly on a basin by basin basis), in order that integrity analyses may be performed. This would need to include:
 1. Maximum static pressures exerted, from casing tests and in production activities.
 2. Cyclic pressures and temperatures that a sheath would be subject to.
- A comprehensive experimental program of measuring the mechanical properties of cement blends used in practice. This would need to include:

1. Curing of the cement at the expected in-situ conditions (pressure, temperature and exposure to water).
2. Evaluation of the experimental testing procedures in order that results can be verified to be independent on the rate of loading and specimen size.
3. Performing a number of compression experiments at downhole temperature to gain an understanding of any potential increased malleability and increased unrecoverable strains that may not be observed in room temperature testing.
4. Performing a range of cyclic loading experiments to understand the fatigue behaviour of well cements.

A University of Adelaide PhD research project has been initiated to begin investigating some of these recommendations and will be published in open, peer reviewed literature in due course.

5.3 Long term integrity

Chemical degradation of well cements way beyond the operational life of the well is a fast emerging field. Researchers have begun to perform experiments in laboratory conditions to measure the effect of chemical reactions between cements and waters encountered underground. Recreating real long term (1000+ years) degradation in a short experiment time (1 year) is very challenging. Similar to the integrity during the operational life of a well, very little data is openly available on the performance of lead cements. Simulation tools are being used to try to forecast the long term behaviour.

5.3.1 Recommendations

It is recommended that:

- An inventory of formation fluid compositions is compiled (on a basin by basin basis), to include:
 1. Chemical compositions of the fluids in different geological layers that the wellbore will be exposed to.
 2. Temperature of fluid sample (chemical reaction rates increase with temperature).
- Details of chemical compositions of cement blends for given depths is collated.
- Numerical modelling of cement degradation exposed to fluids using current state of the art modelling tools in order to have a forecast lifetime of a cement under long term conditions.
- A comprehensive test program of ageing tests with different cement blends is initiated, in particular:
 1. Performing ageing tests of a range of cement blends and formation water chemistries, in order that the numerical tools can be better validated and degradation mechanisms better understood.

2. The efficacy of accelerated ageing tests for the long term prediction of cement degradation is investigated.

A PhD project at the University of Adelaide has begun on the numerical simulation of well cement degradation to address a number of the points raised.

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