FACULTY OF SCIENCE AND TECHNOLOGY

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Abstract

Sustained casing pressure (SCP) has in the later years received increased attention. SCP is the result of gas migration through failed or degraded well barriers manifesting at the wellhead as annular pressures that cannot be effectively bled off. Production and abandonment of such wells is associated with increased risks, but no consistently effective remediation technique exist today. For this thesis, a thorough literature review was conducted on mechanisms leading to leaks, both during well construction and later in the life of a well to provide a better understanding of the problem. The scope of the problem on the Norwegian Continental Shelf (NCS) and regulatory requirements pertaining to the affected wells is discussed. Remediation techniques and why these are often unsuccessful is presented and developments in technology for effective diagnosis and mitigation is discussed.

It is found that the problem can be caused by a variety of factors, and that effective zonal isolation is often compromised by microannulus formation between casing and cement sheath. Recent research has provided some promising solutions for treating the problem and useful insights to be used in the construction of new wells. Understanding the extent of mechanisms leading to SCP is important for solving and preventing the problem.

Acknowledgements

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Nomenclature

ACP	Annular Casing Pressure
APB	Annular pressure build-up
API	American Petroleum Institute
API RP	American Petroleum Institute recommended practice
BOP	Blow-out preventer
CARS	Casing Annulus Remediation System
CBL	Conventional bond log
CSH	Calcium silicate hydrate
EAC	Element acceptance criteria
GOM	Gulf of Mexico
LOT	Leak-off test
MAASP	Maximum allowable annulus pressure
NCS	Norwegian Continental Shelf
NOROG	Norwegian Oil and Gas Association
NORSOK	The Norwegian shelf’s competitive position (Norsk sokkels konkurranseposisjon)
PIT	Pressure-integrity test
PSA	Petroleum Safety Authority
PP&A	Permanent Plugging and Abandonment
RNNP	Risk level in Norwegian petroleum activity
SCP	Sustained casing pressure
SCVF	Surface casing vent flow
SSSV	Sub-surface safety valves
TS	Tensile strength
UCS	Ultimate compressive strength
VDL	Variable-density log
WBE	Well barrier element

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1 Introduction

Sustained casing pressure (SCP) is the appearance of pressure in a casing annulus that persists or reappears after efforts have been made to remove it (Sæby, 2011).

Its definition is any pressure in a well annulus, measured at the wellhead, that rebuilds after being bled down, which are not caused by well operations or changes in temperature. The pressure occurrence is termed *unsustained* casing pressure if the pressure is self-imposed by gas- or water-injection, or caused by temperature fluctuations (Sæby, 2011, Norwegian Oil and Gas Association [NOROG], 2008).

SCP typically occurs due to late gas migration in one of the well's annuli as a result of failed or degraded well barriers. A well barrier is an envelope of one or more dependent barrier elements preventing fluids or gases from flowing between zones in the well (NORSOK, 2021). The source formation of the leakage fluid can be the target reservoir of the well or shallow zones bypassed while drilling (NOROG, 2008, Xu & Wojtanowicz, 2001).

For land wells, the term Surface Casing Vent Flow (SCVF) is more often used for annular flow issues and describes the condition where gas or fluids are flowing from surface casing vent assemblies. In cases where wells are operated with open surface casing vents, flow from the annulus can escape through this vent and result in SCVF. For operations with closed surface casing vents, this flow will result in pressure build-up, often referred to as annular pressure build-up (APB) or annular casing pressure (ACP). Different terminologies are used in different jurisdictions. Regardless of its notation, flow issues and pressure build-ups in annuli are signs of failed well barrier elements and evidence of well integrity issues (Natural Resources Canada [NRCan], 2019, Normann, 2019).

Although most known occurrences of SCP are small and do not pose immediate threats of uncontrolled release, production, and abandonment of such wells are associated with risks (Wojtanowicz, Nishikawa & Rong, 2001). The Petroleum Safety Authority (PSA) regulations require two barriers present for all intervals with hydrocarbon flow potential for permanent plugging and abandonment (PP&A). SCP is evidence of one of these barriers being degraded and would not be acceptable for PP&A (NORSOK, 2021, Ringøen, N., May 10^{th}, 2021. Personal communication with PSA). The topic is becoming increasingly relevant as a large number of wells are nearing the end of their life and having to be permanently plugged with eternal perspectives.

A typical pressure build-up is illustrated in Figure 1.1. This figure is taken from a study by researchers Xu & Wojtanowicz (2001) and shows pressure build up in one of the casings analyzed. In the study it was found that 82% of casings (31 of 38) exhibited this pattern of pressure build up. After being bled off, the pressure quickly increases and stabilizes when approaching a certain level.

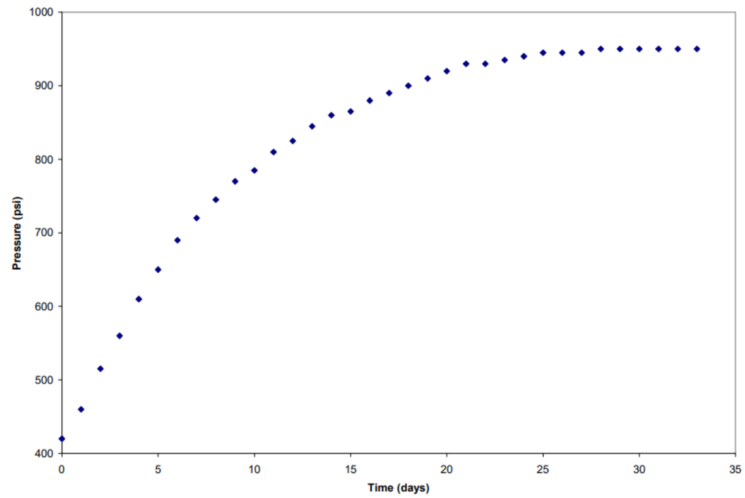


Figure 1.1: Typical SCP pressure build-up (Xu & Wojtanowicz, 2001).

Common leak paths resulting in SCP are outlined with orange arrows in Figure 1.2. As illustrated, leaks can occur both from the inside through leaky connections and seals, between annuli and directly from reservoirs into casings through pathways in the cement. Understanding the source and leak path location is essential for effective SCP management and remediation (NOROG, 2008).

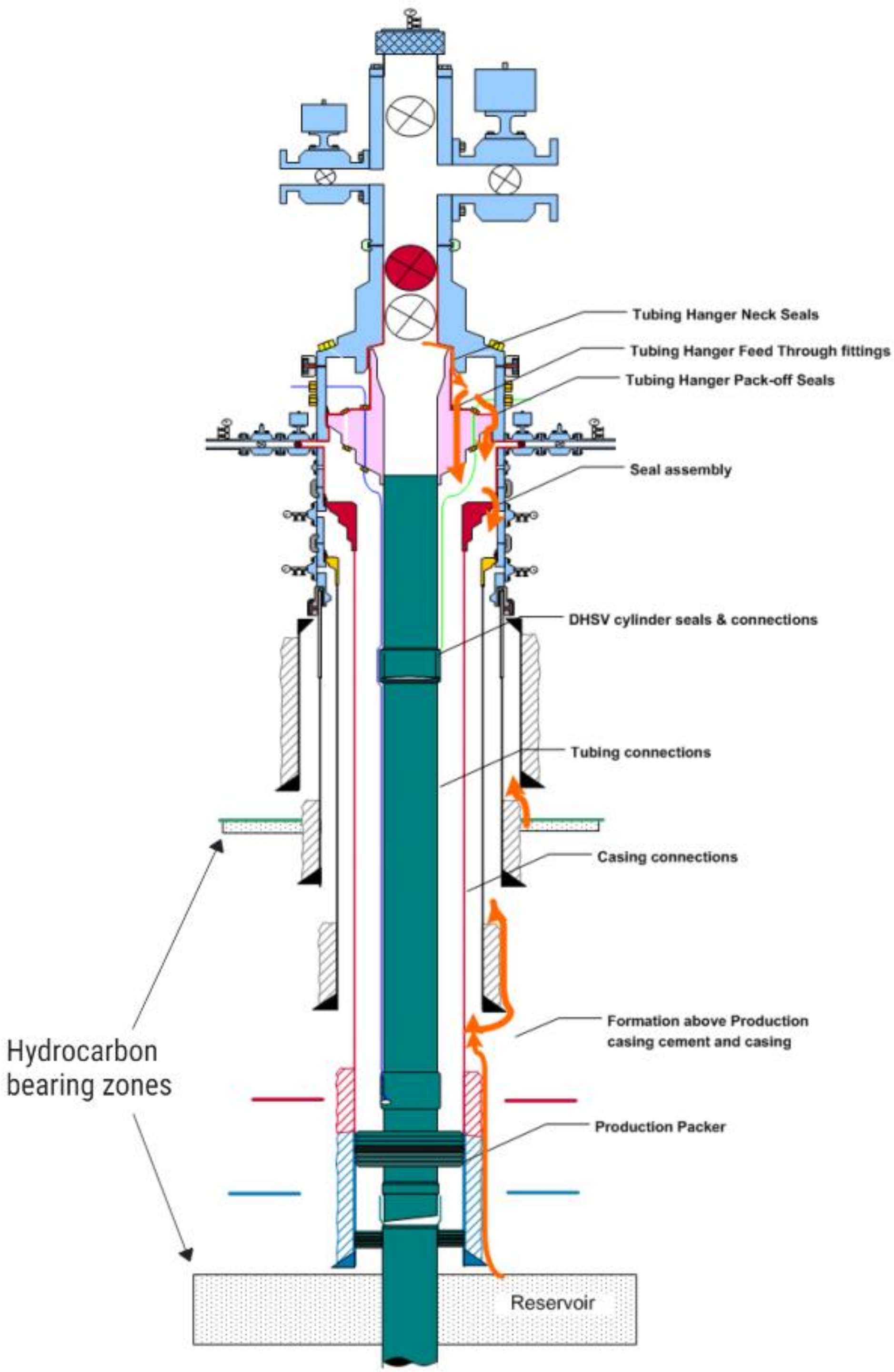


Figure 1.2: Common leak paths resulting in SCP (NOROG, 2012).

1.1 Scope and Objective

The focus of this thesis is to provide a better understanding of the SCP problem. Once established in a well, SCP mitigation has proven difficult and remediation techniques have low success rates. Workover operations are often required for successful mitigation due to the affected areas being hard to access. This involves a high cost, especially in offshore wells if a rig must be brought in. Ideally, the problem should then be eliminated by prevention. Causal mechanisms of SCP are therefore investigated, both during the construction and operational phases of a well. Permanent abandonment of wells on the NCS require a high level of well integrity, and since there is a high probability of more wells being abandoned than new wells constructed over the coming decades an emphasis is put on remediation in existing wells over prevention in new wells. This investigation also includes new technology proposed to aid in SCP mitigation. NCS regulations and occurrences are reviewed to assess the extent of the problem in the Norwegian industry.

1.2 Organization of the Thesis

The scope of the problem and affected wells are discussed in Chapter 2 to define the magnitude of the issue together with available integrity data for NCS wells. Integrity data ties together with the regulatory framework, which is presented in Chapter 3 to define the requirements pertaining to SCP and how this should be dealt with on the NCS. Chapter 4 provides a thorough review of mechanisms that can cause leakage paths leading to SCP. Diagnosis of SCP and its mechanisms is reviewed in Chapter 5. Available remediation techniques are reviewed in Chapter 6. The findings are discussed in Chapter 7.

2 Scope of the Problem

"No statistics for SCP on the Norwegian Continental Shelf (NCS) have been found, but the problem is believed to be significant", stated Jan Sæby of Norske Shell in his presentation in at the Well Integrity Workshop in May 2011 (Sæby, 2011). Available literature still does not offer good data on the scope of the problem on the NCS. PSA regulations governing petroleum activity on the NCS follow a trust-based system, as opposed to a supervision-based system like several other producing countries. NCS operators are therefore not required to report annulus pressures to the authorities, and PSA does not hold statistics on annular pressures or SCP occurrences on the NCS. Consequently, specifics regarding SCP problems on the NCS are not publicly available (Ringøen, N., May 10th, 2021. Personal communication with PSA). In order to understand the magnitude of the problem, we have to look at other producing countries' statistics.

The Mineral Management Service (MMS) show 11 498 casings strings in 8 122 wells in the Gulf of Mexico (GOM) exhibit SCP (Wojtanowicz, Nishikawa & Rong, 2001). A report by Wojtanowicz et al. (2001), analyzing casing pressure data form 26 wells, found that 85% of the wells (22 of 26) exhibited SCP problems. The study by Xu & Wojtanowicz (2001) analyzing pressure build-up patterns found similar statistics. Data from the Alberta Energy Regulator (AER) in 2016 shows that 5.8% of Alberta's near 440,000 wells have reported SCVF and that inactive and abandoned wells were the most prone to leakage. 10.3% of all inactive wells had reported leakage, and 7.0% of all abandoned wells had reported leakage. 96.7% of 10,326 leaking wells in 2016 were classified as non-serious (NRCan, 2019).

2.1 2006 PSA Well Integrity Survey

PSA performed a pilot survey in 2006 to evaluate the well integrity status of the NCS. In order to achieve representative statistics, 12 installations with 581 wells were chosen as candidates for the project. Abandoned and inactive wells were excluded, and a total of 406 wells, 323 production- and 83 injection wells were assessed. PSA then audited the seven relevant operating companies and requested well integrity status for the pre-selected wells (Vignes, Andreassen & Tonning, 2006).

18% of the wells surveyed, 75 of 406, reported to have well integrity failures/issues or uncertainties. Of these, 41 were producer wells (13% of total producer wells surveyed), and 34 were injector wells (41% of total injector wells surveyed).

The well integrity impact was classified into three categories; Category A - Well is shut in, Category B - Working under conditions/exemptions, Category C - Insignificant deviations for current operations. The well integrity impact was distributed as follows:

Category A - Well is shut in: 28 of 406 wells (7%)
Producer: 18 of 323 wells
Injector: 10 of 83 wells

Category B - Working under conditions/exemptions: 38 of 406 wells (9%)
Producer: 22 of 323 wells
Injector: 16 of 83 wells

Category C - Insignificant deviations for current operations: 9 of 406 wells (2%)
Producer: 8 of 323 wells
Injector: 1 of 83 wells

Peak intensity of integrity impairment was observed for 10 - 14 year old wells (wells completed in 1992 - 1996). It was found that wells from the early 1990s showed on average twice as high integrity impairment as other wells surveyed (Vignes et al., 2006). The survey also found that production tubing was the dominating failure component (NOROG, 2012).

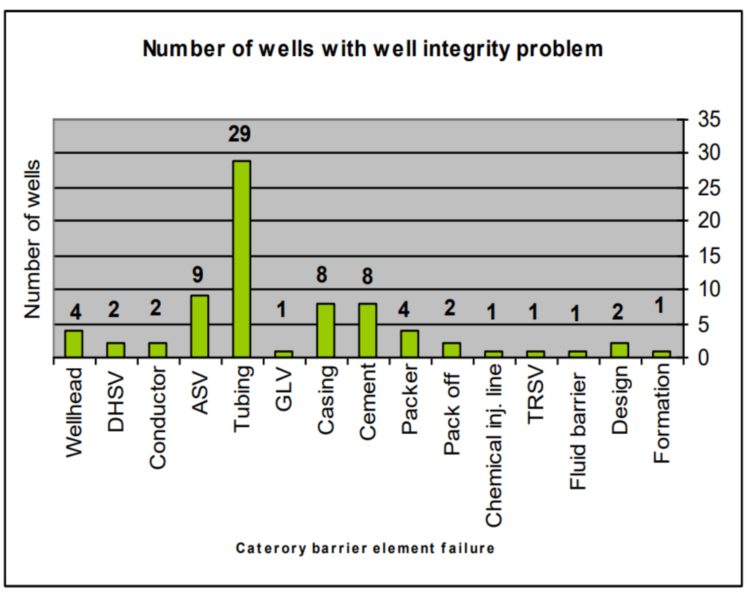


Figure 1.3: Number of wells with integrity problems, sorted by barrier elements (NOROG, 2012).

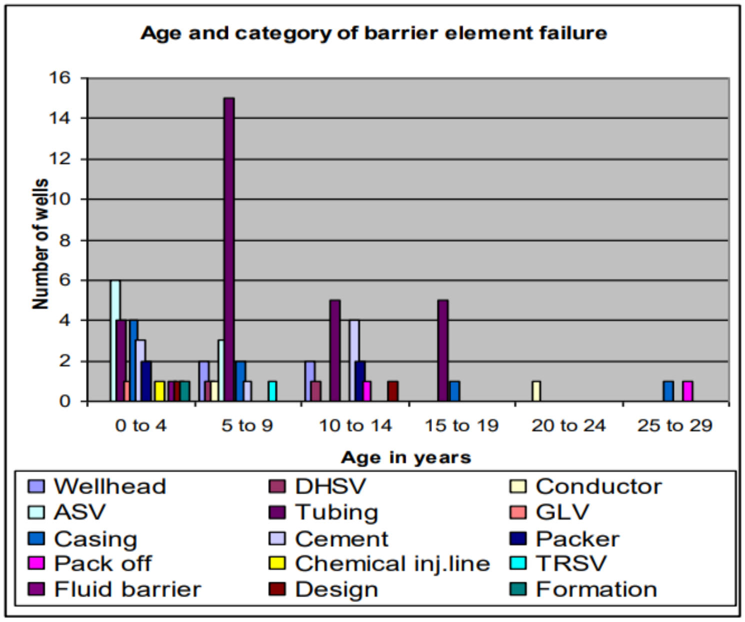


Figure 1.4: Age and category of barrier element failures (NOROG, 2012).

All seven companies participating agreed that the well integrity status comprising the survey was representative of the current situation for the selected installations. PSA believed the findings to be representative of the general NCS conditions.

PSA initially executed the survey as a "pilot", and the report referred to above was termed Phase 1. Due to the significance of the findings, PSA claimed a more comprehensive study, Phase 2, should be commenced (Vignes et al., 2006). Phase 2, however, was never concluded (NOROG, 2012).

2.2 Well Integrity Categorization System

WIF developed a system of classifying wells for reporting purposes in response to industry and regulatory interest. The classification system is used by PSA to summarize the NCS well integrity status in a yearly report called the RNNP (risk level in Norwegian petroleum activity) report. The common categorization system also promotes consistency in operator reports of integrity status to PSA (NOROG, 2012).
The categorization system uses a color-coding system, for visual purposes, with the colors green, yellow, orange and red. The categorization is made of the entire well, and all conditions and WBEs should be evaluated together.

Category	Principle
Red	One barrier failure and the other is degraded or not verified, or leak to surface
Orange	One barrier failure and the other is intact, or a single failure may lead to leak to surface
Yellow	One barrier degraded, the other is intact
Green	Healthy well – no, or minor issue

Table 1.1: Categorization principles (NOROG, 2008).

Green category: A well will fall into the Green category if its associated risks are comparable to that of a new well with identical well design in compliance with regulations. Green category wells entirely fulfill regulatory requirements or have minor integrity issues that do not risk causing degradation of well barriers. A well exhibiting SCP can fall within the this category if there are no leaks through the primary or secondary barriers, no hydrocarbon in the annuli, annulus pressures are within the operating envelope and the leak rate into annulus is within acceptable criteria (rates stated by API RP 14B) (NOROG, 2008).

Yellow category: A well will fall into the Yellow category if it has an incremental, but acceptable, associated risk. These risks are *not negligible* when compared to a new well with identical design in compliance with regulations. Although there is increased risk associated with wells in the yellow category, the wells are in compliance with regulations.
Similar to Green category wells, a well exhibiting SCP can fall within the Yellow category if there are no leaks through the primary or secondary barriers, annulus pressures are within the operating envelope and the leak rate into annulus is within acceptable rates. A distinction is made for the presence of hydrocarbons and a well will fall into the Yellow category when the above criteria are met, but hydrocarbons are present in the annulus (NOROG, 2008).

Orange category: A well in the Orange category will have an associated risk higher than that of a new well with identical well design in compliance with regulations. Orange category wells are typically not in compliance with regulations, and repairs are required before being put into normal operation. One well barrier is intact and there will usually not be an immediate need for action.

A well exhibiting SCP will fall into the Orange category if the leak rate into annulus is outside acceptance criteria, but annuli pressures are within operating envelopes (NOROG, 2008).

Red category: A well will fall into the Red category if its associated risks are unacceptable and significant when compared to a new well with identical design in compliance with regulations. Red category wells are typically not in compliance with regulations and the need for attention or repairs is usually immediate. A well should be categorized as Red if one WBE in a barrier envelope has failed and one WBE in the other barrier envelope has failed, is regarded as degraded or its status is not verified.

A well exhibiting SCP will fall into the Red category if the leak rate into annulus is outside acceptance criteria and annulus pressure is above defined pressure limits (NOROG, 2008).

2.3 NCS Well Integrity Status – RNNP

The RNNP report is a yearly publication from PSA. The report measures the development in risk levels for all aspects of petroleum production. Relevant for this thesis are the data on well categorization (Petroleum Safety Authority [PSA], 2019). The RNNP report for 2020 found that 31% of wells on the NCS had a degree of integrity impairment, based on data reported by operators to PSA. The report does not provide reasons for integrity impairment.

Of the total 2087 wells, 69.0% were categorized as Green, 27.7% Yellow (570 wells), 3.0% Orange (62 wells) and 0.3% Red (6 wells). Five temporarily abandoned and one shut in well accounted for the wells in the Red category. The statistics are based on 13 operators, 2 of these reported to have wells in the Red category. Three operators reported all of their wells in the green category (PTIL, 2021).

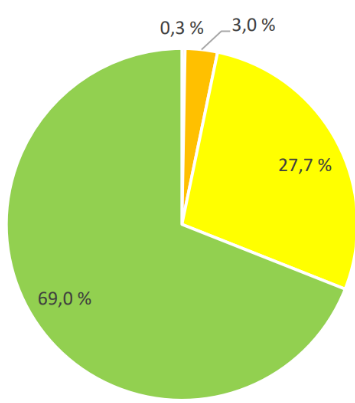


Figure 1.5: 2020 RNNP well categorization - Red category wells account for only a few pixels in the pie chart and are barely visible (PSA, 2021).

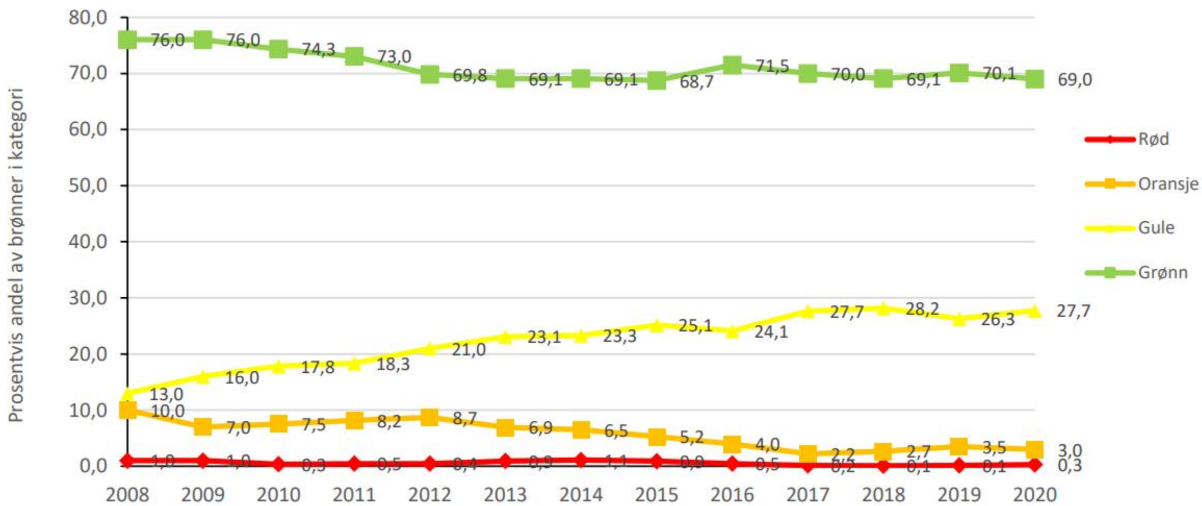


Figure 1.6: RNNP well categorization from 2008 – 2020. Wells in the red category have remained relatively constant since reporting started in 2008 (PTIL, 2021).

2.4 Summary

SCP is clearly a problem in a large number of wells, but statistics on the particular extent are not available on the NCS. SCP affected wells are categorized according to the Well Integrity Categorization System and reported potentially together with other integrity issues, causing these details to be “lost”. The study by Vignes et al. (2006) provides some insights into elements that have failed, but the types of issues caused by these failures are not included.

3 Regulations

3.1 PSA – Petroleum Safety Authority

Production of petroleum on the NCS is regulated by PSA. PSA is a state funded agency regulating all aspects of the industry, including planning, development, construction, activities, and decommissioning. PSA regulations are built on the «distribution of responsibility» concept, meaning that actors are responsible for handling the risk they own. Regulations on the NCS are therefore largely based on functional requirements. These requirements define which levels of safety must be achieved, but not how to achieve them. Operators are free to, and responsible for, developing solutions that meet the requirements set by PSA. This model is used in order to promote technological advances and operator responsibility. It also promotes trust between operator and authority.

Guidelines to the different regulations are developed by PSA advising how regulatory requirements can be met. These guidelines are based on both Norwegian and international industry standards, such as NORSOK and API, for solutions and procedures. If recommended methods are used, the requirements are considered to be met. If an operator applies a different solution in order to meet requirements, they are responsible for documenting that the requirement is met (NOROG, 2008, PSA, 2017).

Section 8 of the Management Regulations by PSA is stated as follows:

Management Regulations §8 – Internal requirements

The responsible party shall set internal requirements that put regulatory requirements in concrete terms, and that contribute to achieving the objectives for health, safety and the environment, cf. Section 7 regarding objectives and strategies. If the internal requirements are expressed as functional requirements, achievement criteria shall be set. The operator shall ensure agreement between its own requirements and between its own and other participants' requirements (Management Regulations, 2020, §8).

The responsibility for determining detailed requirements for annuli pressures is therefore left to the individual industry operator.

3.2 NORSOK D-010

NORSOK is a project started in 1993 with the purpose of ensuring safety and efficient production of petroleum resources in the Norwegian industry. The project is a collaboration between actors and associations in the industry and is mostly known for its set of nationally recognized industry standards. These standards act as company specifications where possible and serve as references in the authorities' regulations (Johansen, Langeland, Tangen & Haugland, 1996).

NORSOK D-010 is the governing standard regarding well integrity on the NCS. This standard sets the minimum requirements for solutions and equipment to be used by operators in well operations (NOROG, 2012).

NORSOK D-010 defines well integrity as "*application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well*" (NORSOK D-010:2021, 3.74).

Similar to PSA regulations, which solution to use in order to comply with the minimum requirements is not defined in the standard. Operators are themselves responsible for choosing a solution that meets the requirements set by NORSOK D-010.

The term SCP is not used in NORSOK D-010, but relevant requirements fall under the chapters "*General barrier principles*" and "*Production activities*". The applicable requirements regarding SCP are stated as follows:

5.2.3.6.2. Acceptable leak rates

The acceptable leak rate shall be zero, unless otherwise specified in EACs. For practical purposes acceptance criteria should be established to allow for volume, temperature effects, air entrapment and media compressibility. For situations where the leak rate cannot be monitored or measured, the criteria for maximum allowable pressure change (stable reading) shall be established (NORSOK D-010:2021, Chapter 5.2.3.6.2.).

5.6 Activity and operation shut down criteria

Criteria for shut-down of the activities or operations shall be established.

Normal activities and operations shall cease, when:

a) having an unassessed/impaired well barrier/well barrier element or a failed well barrier/well barrier element;
b) there is a high probability for exceeding allowable operating limits of well control equipment and other essential equipment;
c) H2S/CO2 content of fluids or gases exceeds personnel exposure limits, operating limits of the well control equipment and other essential equipment (NORSOK D-010:2021, chapter 5.6.).

9.6.4. Annulus pressure management

Maximum and minimum operating annulus pressures shall be defined for all accessible annuli. The operating pressure range shall be set to ensure that the design limitations (load cases) and verified test pressures are not exceeded for the individual annuli/ exposed WBE. For annuli open to the formation, the minimum formation stress should not be exceeded unless this is a planned contingency during the well design (e.g. subsea wells where B-annulus is not cemented).

The following shall be considered when defining the operating range:

a) the effect of temperature changes (well stream, ambient) on the annuli pressures, especially during emergency shut down situations;
b) the available response time to bleed off or top up annuli;
c) variation in the tubing and annuli fluid densities; and
d) occurrence of pressure communication between annuli or escalation of risk if such communication should occur.

The pressure in all accessible annuli shall be monitored and maintained within minimum and maximum pressure range limits. All accessible annuli should be maintained with positive pressure for leak detection and pressures should be kept with differential pressure between all annuli.

The annulus bleed system should always be liquid filled. When gas has been bled off from the annulus, the annulus bleed system should be replenished with liquid. Hydrate inhibition shall be considered.

See Norwegian Oil and Gas Guideline no. 117, "Recommended guideline for well integrity" for defining the annulus pressure operating envelopes (NORSOK D-010:2021, Chapter 9.6.4).

In short, NORSOK requires monitoring of pressure in accessible annuli for detecting possible well barrier impairment. Operating envelopes are established to account for pressure changes caused by well operations and shut down criteria are established in order to keep HSE risks as low as reasonably practicable.

3.3 Norwegian Oil and Gas Guideline no. 117 – Recommended Guidelines for Well Integrity

Norwegian Oil and Gas Guideline no. 117 is a document by Norwegian Oil and Gas Association (NOROG) developed in participation with central parties in the Norwegian petroleum industry at the Well Integrity Forum (WIF). The guideline was developed to supplement the regulations and present recommendations and best practices for well integrity issues on the NCS, including SCP. NORSOK D-010 chapter 9.4.6 refers to this document for defining annulus pressure operating envelopes (NORSOK, 2021, NOROG, 2008).

Annulus pressure criteria are defined as follows:

6.3.2 Annulus pressure criteria
Excessive annulus pressures increase the probability of failures resulting in loss of containment and potentially uncontrolled release.
The objective when determining acceptance criteria for annulus pressure, maximum allowable annulus surface pressure at the wellhead (MAASP), is therefore to identify a pressure at which the probability of failure is as low as reasonably practicable and normal operation of the well is allowed (NOROG, 2008, Guideline no. 117, Chapter 6.3.2).

To summarize, NCS regulations do not offer specific laws or requirements on SCP. The issue falls under functional requirements for well integrity and well barrier elements, and operators are in large responsible themselves for determining acceptance criteria and pressure range limits. A general guideline and practices considered appropriate are presented in Guideline no. 117. Regulations are considered to be met if these practices are followed. Operators can choose to apply different practices to meet the requirements, but documentation that requirements are met must then be presented to the authorities (PSA, 2017). As of April 2021, PSA is working on updating the guidelines to the Management Regulations to include references to Norwegian Oil and Gas Guideline no. 117 (Ringøen, N., April 7th, 2021. Personal communication with PSA). The following section summarizes recommended practices on SCP according to Guideline no. 117 that would ensure regulations being met, sourced from NOROG (2008).

3.3.1 Recommended Practice

Monitoring and Detection

SCP can be caused by a variety of factors and can occur throughout the lifetime of the well. Regular monitoring to ensure early detection is an important part of SCP management.

NORSOK D-010 9.6.4 states that pressures in all accessible annuli shall be monitored and maintained within pressure range limits. This is done to ensure that the integrity status of a well is known at all times. Due to the effects of temperature and flow on annuli pressures, these parameters are also monitored in order to correctly interpret pressure changes and identify abnormal annuli pressures.

Significant pressure changes in annuli are expected during well operations such as producer start-ups, where a well will warm up, and shut-ins, where a well will cool down. Injection wells tend to be injected with fluids at lower temperatures than the surroundings of the well. This will cause a pressure increase when the well is shut-in as the temperature increases. After the start-up of a well, annuli pressures are expected to stabilize at the same levels as prior to a shut in - given that operations such as top ups or bleed downs have not been performed. Deviations from these expected pressure patterns can be an indication of SCP.

Build-up of SCP often happens over longer periods of time (illustrated in Figure 1.1) and detecting SCP behavior from short time interval data can therefore be difficult. The assessment of pressure trends over longer time periods, like weeks or months, are recommended for appropriate SCP diagnosis.

Leak Rates - API RP 14B

High leak rates are associated with unacceptable consequences if leak containment is lost. Acceptance criteria are therefore determined with respect to the consequences of an unintended or uncontrolled release to the surface. The objective is to identify a leak rate where a release does not lead to unacceptable consequences and the probability of an escalated situation is as low as reasonably practicable.

The American Petroleum Institutes recommended practice (API RP) 14B is an industry standard establishing requirements on sub-surface safety valves (SSSV). Acceptable leakage rates for SSSV are defined by API RP 14B as:

0.42 Sm^3/min for gas
0.4 litre/min for liquid

Leakages below these rates are considered to have acceptable and manageable consequences if released to surface. Although not intended to define SCP criteria, the rates stated in API RP 14B is regarded as applicable when determining SCP acceptance criteria. Using the API RP 14B criteria when determining acceptable leak rates through well barrier elements (WBEs) are also largely considered an industry norm and appropriate by Norwegian Oil and Gas Guideline no. 117 ((Normann, 2019, NOROG, 2008).

Escalation Potential Evaluation

After SCP has been confirmed, the escalation potential must be evaluated. Potential consequences of SCP depend on the amounts of flammable hydrocarbon gas contained in the annulus, which can be released if containment is lost. Determining the volume and mass of trapped gas is an integral part of the evaluation.

Volume

Hydrocarbon gas volume can be estimated by identifying the gas/liquid contact level in the annulus. This can be done using acoustic measurement techniques and tools such as an echometer. An alternative approach is to bleed off the trapped gas and replenish with liquid, measuring the volume of liquid required to fill the annulus.

Mass

Hydrocarbon gas mass is calculated based on gas properties, gas volume and annuli pressure. Gas will dissolve in liquids at higher pressures and liberate when pressure is decreased. Assessment of hydrocarbon gas volume should therefore be done at different pressure intervals, in order to make the best estimation of the total free hydrocarbon gas at standard conditions. Due to the uncertain nature of these parameters, conservative estimations are recommended.

In addition to volume and mass, a thorough escalation potential evaluation will consider source and mechanism of the leak, and risks posed to well components and the installation. Corrosion and erosion can result in increasing leak rates over time, and hostile reservoir fluids can cause degradation of well equipment. Such effects can also be magnified by frequent bleed downs of the annulus pressure. In some cases, introducing foreign fluids into the annulus can result in changes to load scenarios and lead to load cases not considered in the initial well design. The combined effects of potential degradation of well equipment and changes in load scenarios caused by SCP should be considered in the evaluation.

In rare cases, H_2S and radioactive agents can be introduced to the annuli through SCP. Such substances pose considerable HSE risks and an evaluation should verify that no such potential is present. NORSOK D-010 5.6 state that normal well operations shall cease when H_2S contents in fluids or gases exceed personnel exposure limits (NOROG, 2008, NORSOK, 2021).

Annulus Pressure Criteria

The probability of loss of containment and uncontrolled release increases with increasing annulus pressures. Acceptance criteria for annulus pressure, maximum allowable annulus surface pressure (MAASP) is therefore established at a level where the probability of failure is as low as reasonably practicable. A key part of SCP evaluation is investigating the potential pressures caused by pressure build-ups. Potential maximum stabilized pressure can be evaluated through controlled pressure build-ups. The MAASP should be clearly defined for such assessments. Build-ups should be discontinued if this limit is approached, regardless of pressure stabilization (NOROG, 2008).

4 Causes of Leaks

Wellbore leakage fundamentally requires a leak source, a driving force, and a pathway. The principle leakage fluid is natural gas, and source formations are often thin, gas-bearing strata bypassed during drilling to the target hydrocarbon reservoir (NRCan, 2019). The driving forces include reservoir pressure and buoyancy force due to the lower density of natural gas than crude oil or saline water. Leakage paths are typically attributed to the failure of annulus cement, but leakage can also occur from inside to outside the casing. The development of leakage paths can be attributed to two main categories. Defective well construction can create immediate concerns of cement integrity, while post-completion defects develop later in the lifespan of the well due to production and operations in the well. The following well construction principles are based on procedures described by Nelson & Guillot (2006) and University of Stavanger [UiS] (2018).

4.1 Well Construction

In order to fully understand the mechanisms and failure scenarios that can lead to leak paths and SCP, a basic understanding of well design is required. Ideally, the entire well would be drilled from surface to reservoir in one section and consist of one hole with a uniform diameter. This is, however, generally not possible due to geological and pressure challenges. Wells are therefore drilled in sections with casings being set at different intervals to isolate problem formations. General well construction with typical dimensions for a North Sea well is outlined in the following steps:

Drilling and installing a 30” Conductor casing – The conductor casing is the first and largest diameter casing used in a well. It protects shallow formations from drilling fluids and isolates unconsolidated surface formations from collapsing into the hole in the later stages. It serves as a foundation for the well head and blow out preventor (BOP) and carries the weight of all lower casing sections. In order to withstand the tensile forces and loads posed by other well components, the conductor casing is fully cemented from the seabed down to the casing shoe.

Drilling and installing a 20” Surface casing – After the conductor casing has been cemented, a 26” hole is drilled through unconsolidated shallow formations to approximately 600m. During drilling, mud is circulated down the drill pipe and across the face of the drill bit to remove cuttings, carrying these up to surface through the annular space between the borehole and the drill string. After drilling to the desired depth, the drill string is pulled from the hole and a 20” surface casing is installed. The surface casing consists of several 40 ft. casing sections with threaded connections, which are fitted together as the casing is lowered into the hole. After reaching the bottom, cement slurry is pumped down into the annulus between the casing and the borehole. The entire length of the surface casing is cemented. This cement sheath acts as a seal between casing and borehole, prevents unconsolidated shallow formations from collapsing into the deeper sections and protects the well against blowouts. A wellhead is installed on the surface casing to support the weight of subsequent casing strings.

Drilling and installing a 13 3/8” Intermediate casing – The intermediate casing is set in a 17 ½” hole extending down to 1500 – 2000m. At these depths there are chances of encountering formations containing fluid under high pressures, and a BOP is therefore installed on top of the wellhead to prevent uncontrolled releases before the any drilling takes place. The intermediate casing isolates the well from troublesome formations and protects the formation from fracturing due to the hydrostatic pressures provided by the drilling mud. The wellhead housing supports the intermediate casing while its’ cemented in place. Intermediate casings are usually cemented only partially, creating an open annulus between the surface casing and intermediate casing. This annulus is referred to as the C-annulus.

Drilling and installing a 9 5/8” Production casing – The production casing is the last casing in the casing string. A 12 ¼” hole is drilled through the target reservoir, and a production casing is installed. Similar to the intermediate casing, the production casing is also just partially cemented, creating an annulus between the intermediate casing and the production casing, referred to as the B-annulus.

Well Completion – After all casings have been set and cemented, production tubing is run inside the production casing in order to transport hydrocarbons to the surface. The annulus between the production casing and the production tubing, referred to as the A-annulus, is sealed off by a packer. The packer consists of rubber seals expanding between the casing and tubing and is installed just above the pay zone. The last step of well completion is perforating the production casing adjacent to the pay zone before hydrocarbon.

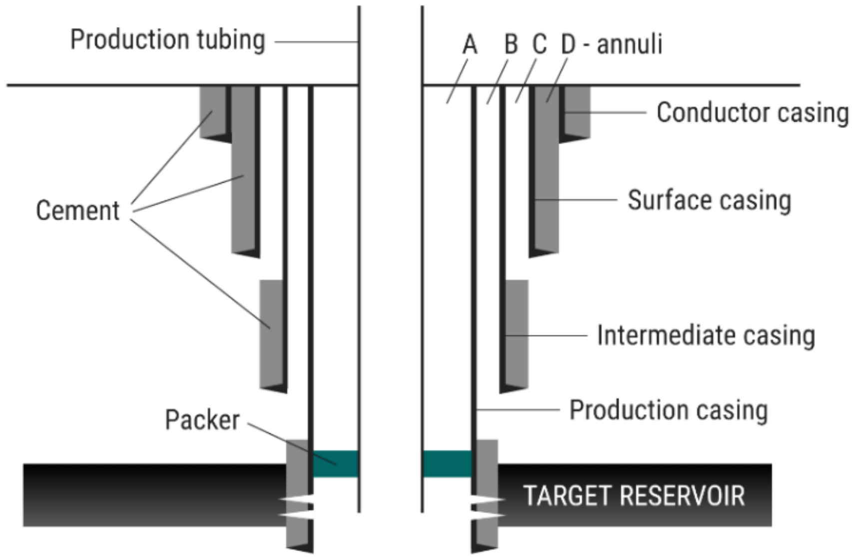


Figure 4.1: Basic well construction – based on schematics from UiS (2018).

4.1.1 Primary Cementing

The cementing process described above is called primary cementing. The main objectives of the primary cement job is providing zonal isolation and supporting the casings, and a properly executed primary cement job will provide a continuous and impermeable seal within the annulus that isolates all zones along the wellbore (Docherty et al., 2016). The process is planned and executed carefully as the operators only have one chance at a successful primary cement job (Nelson & Guillot, 2006). Poor primary cement jobs are a major cause of leakage paths (NRCan, 2019).

In most cases, the cementing process follow the same principles regardless of the size and type of the casing. Cement mixtures are designed based on casing type, depth, pressure, temperature, and factors regarding the section of the borehole that is to be cemented. A slurry of cement, water and cement additives is mixed and pumped down the casing and into the annulus. After drilling to the desired depth and installing the casing, the annulus is filled with drilling fluids. In order for the cement to achieve a good bond and effective zonal isolation, drilling fluids must be removed from the annulus prior to cement placement. A spacer fluid is therefore pumped into the casing prior to the cement slurry to condition the borehole and displace the mud upwards. The cement is followed by a displacement fluid, which displaces the cement into the annulus, where it is left until set (Beirute, Sabins & Ravi, 1991).

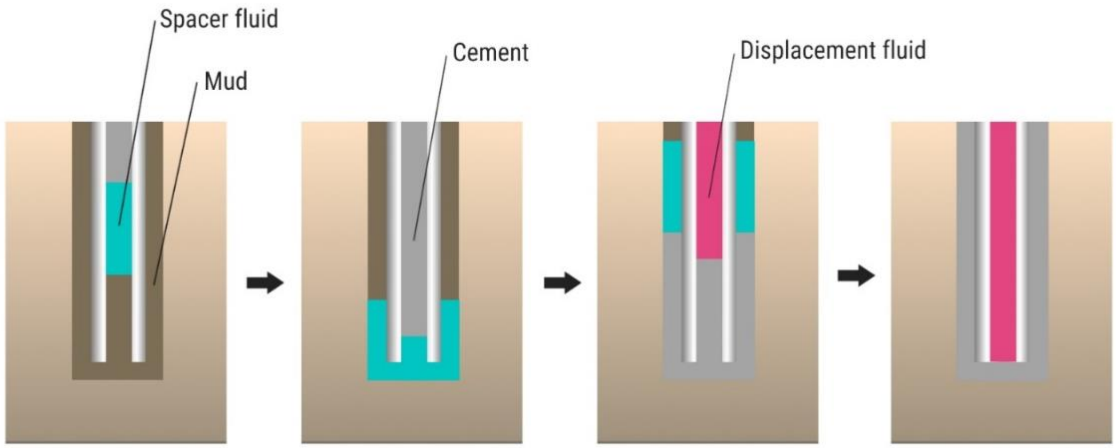


Figure 4.2: Primary cementing and hole conditioning – based on figures from Nelson & Guillot (2006).

4.1.2 Hole Conditioning and Mud Displacement

Proper hole conditioning means establishing a borehole free from cuttings and debris, and with mud in a «displaceable» or «circulatable» state in order to allow the spacer fluid to displace the mud up through the annulus (Beirute et al., 1991). To achieve effective mud displacement, the operation must ensure that drilling fluids are thinned and dispersed, and debris are lifted out of the annular space by a spacer fluid. Weakening and thinning mud cake and clearing the casing from drilling fluids are also objectives of the spacer. Typically, drilling fluids and cement slurries are incompatible and can form a highly viscous mixture if allowed to mix. The spacer is compatible with both and is therefore pumped between them to avoid this from happening. This is where the name – spacer – comes from (Docherty et al., 2016).

Modern spacer fluids are designed to have specific fluid properties, and solvents and surfactants are often added to improve cleaning and displacement efficiency. Because some volume of the spacer fluid will contaminate the cement, the spacer fluid chemistry is designed such that cement properties are not altered. In wells drilled with oil-based mud, surfactants can be added to the spacer fluid in order to change the wettability of the casing and formation from oil-wet to water-wet, like the cement, prior to cementing.

The flow regime of the spacer fluid is also considered, and a turbulent flow is typically preferred for hole conditioning. During turbulent flow, the spacer fluid moves in erratic circular motions and the fluid velocity remains nearly the same throughout the borehole, which provides better cleaning of mud cake from the borehole walls. In laminar flow, fluid flow lines are parallel and individual particles move with parallel paths which makes the removal of mud particles caught on the borehole walls difficult (Docherty et al., 2016). Improper hole conditioning and poor mud displacement can result in leakage paths and lead to SCP, and will be further discussed in a later chapter.

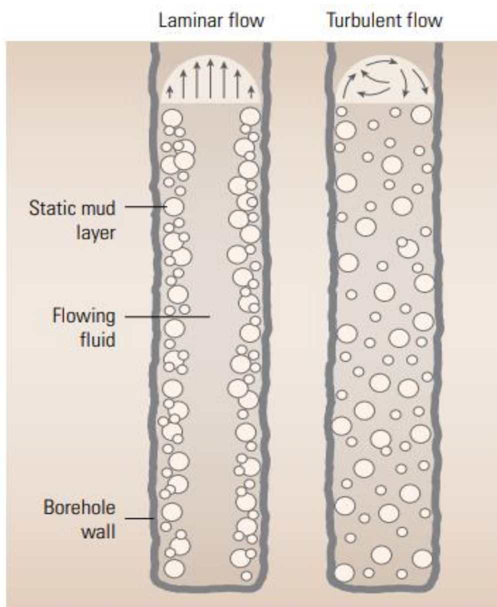


Figure 4.3: Mud removal flow dynamics (Docherty et al., 2016).

4.1.3 Cement Hydration Behavior

To ensure wellbore integrity and prevent cement failure throughout the life of the well it is important to understand the behavior of the cement sheath during and after hardening (Zhang, Eckert & Hilgedick, 2019). Portland cement, used in the majority of well cementing operations, is a powder that in reaction with water evolve towards a solid material. The powder consists of a mixture of clinker and calcium sulfate. Clinker is made by heating a mixture of calcareous and argillaceous raw materials. Proportions, structure, and surface-area of the materials will determine the cements final properties, although cement additives can also be added to further adjust or achieve certain properties (Bois, Garnier, Rodot, Saint-Marc & Aimard, 2011).

Hydration of cement is an intricate reaction that involves chemical, thermal, and mechanical processes between water and cement compounds. Several periods have been identified in the hydration process in which different chemical processes occur. When water is added to cement, there is an initial fast hydration that forms a layer of gelatinous material – calcium silicate hydrate (CSH) gel. Calcium hydroxide crystalizes and form as hexagonal plates. The CSH gel continues to grow between cement grains and forms a matrix that binds the various components (Bois et al., 2011). The hydration reaction is affected by factors such as water supply, curing temperature and pressure and can directly affect the hydration process and set cement properties. Cement hydration is a long-term process that can last up to months until all chemical reactions conclude, although reaction rates decrease significantly and cement sheaths typically achieve their desired properties in a matter of hours or days depending on the cement mixture (Zhang, Eckert & Hilgedick, 2019). At the end of the hydration process, the set cement microstructure consists of anhydrous grains, high-density CSH gel, low-density CSH gel and Portlandite as its main elements.

After the hydrostatic pressure in the cement column decreases to formation pressures, the hydration process causes an absolute reduction in the volume of the cement matrix. Because the end products (cement hydration products and water) occupy a smaller volume than the initial components (reactive cement powder and water) intergranular pores are produced, and cement should therefore be considered a porous material. Water is trapped in these pores by capillary forces but is gradually consumed in the hydration process, and a void resulting in pore pressure reduction is created. Furthermore, intragranular pores exist in CSH grains, while Portlandite is considered non-porous (Bois et al., 2011, Wojtanowicz et al., 2001).

Two microscale heterogeneities must also be considered in the cement structure. Firstly, the different phases present in the microstructure have different mechanical properties, like described in Table 4.1. Significant differences in bulk-modulus for adjacent materials can lead to incompatible deformations at the interface between them, and microcracks might develop and impact the mechanical properties (Bois et al., 2011).

Phase	**Bulk-modulus**
Low-density CSH	14 GPa
High-density CSH	19 GPa
CH crystals	32 GPa
Portlandite	104 – 121 GPa

Table 4.1: Mechanical properties in different set-cement components (Bois et al., 2011).

The second type of heterogeneity is caused by areas in the microstructure with different porosities, which will lead to different average mechanical properties. Microcracks can occur between areas of different elastic moduli in the microstructure, even under isotropic and evenly distributed loads (Bois et al., 2011).

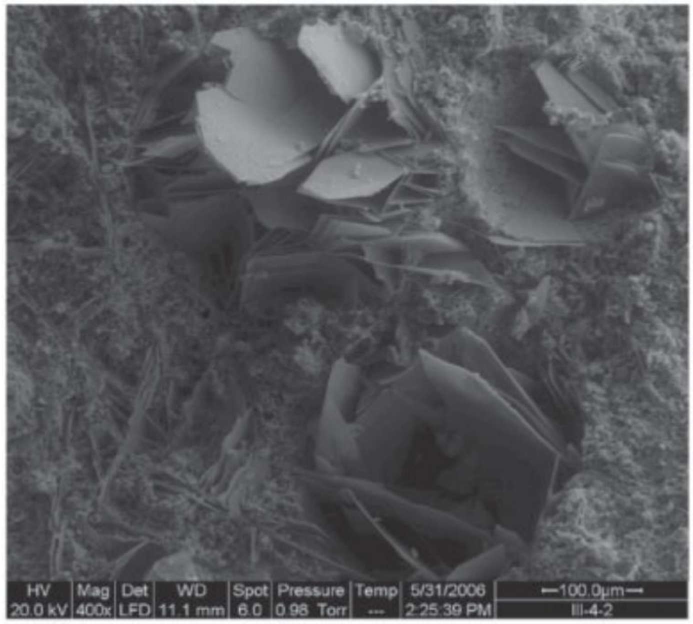


Figure 4.4: Set cement microstructure – Pores are visible (Bois et al., 2011).

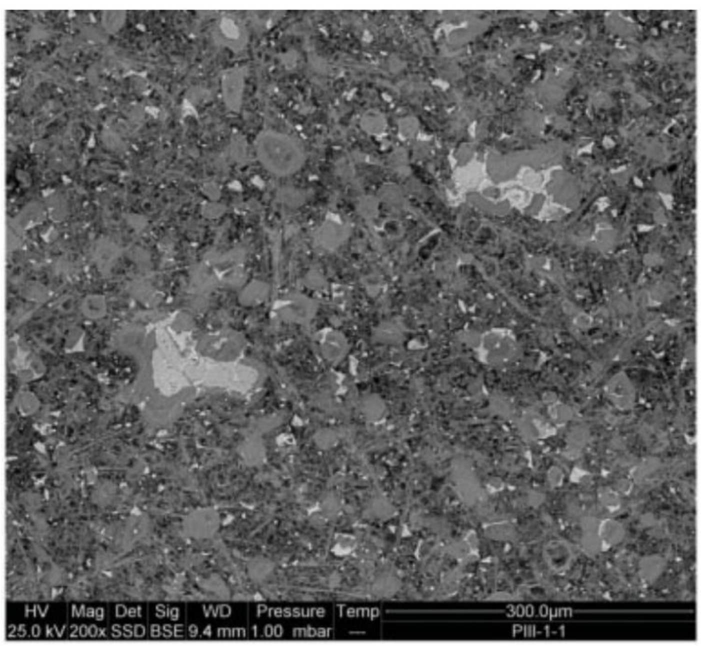


Figure 4.5: Set cement heterogenous microstructure (Bois et al., 2011).

4.1.4 Set Cement State of Stress

The initial state of stress in the cement sheath is critical because it determines how far the cement is from yielding and therefore the loadings it can be subjected to before damage occurs. Most authors disagree on this topic. Several hypotheses have been presented om the subject, including:

- Set cement is under no initial effective stress after having set (Nelson & Guillot, 2006)
- Initial stresses are zero if there is a net shrinkage during curing, and stresses are equal to the formation hydrostatic pressure if there is no net shrinkage (Bois et al., 2011)
- Initial stresses are equal to the hydrostatic pressure and stresses caused by expansion, if there is expansion (Bois et al., 2011)

None of the hypotheses have been confirmed by validation against field experience.
The importance of initial stresses can be explained in an example. For a cement rated for 30 MPa ultimate compressive strength (UCS) and 3 MPa tensile strength (TS), its interval in which it remains undamaged is [-3 to 30] MPa. If subjected to a loading cycle posed by a leak-off test (LOT) which increases stresses by 10 MPa, followed by a fluid swap which decreases stresses by 15 MPa, no damage will occur if the initial state of stress is 10 MPa as stresses are contained within the strength limitations. However, if the initial state of stress is 0 MPa, the pressure increase will cause no damage, but the pressure decrease will cause tensile damage as the final stress is -5 MPa. Similarly, if the initial state of stress is 25 MPa, the pressure increase will cause compressive damage as the final stress, 35 MPa, is above UCS values.

Mistaking the initial stresses can therefore lead to misconceptions in the cement design, e.g. designing against tensile damage when compressive damage should occur, designing against compressive damage when tensile damage should occur or assuming no damage will occur when it should.
Research suggests that “high levels” of stress (above 0 MPa) are present in cement sheaths located between two impermeable casings after the cement has set. However, if the cement sheath is in contact with a permeable formation, this initial stress will change due to pore pressure variations causing an increase in pore pressures in the cement sheath, increased total stresses and reduced effective stresses.
Available literature does not offer conclusive theory on set cement initial state of stress (Bois et al., 2011).

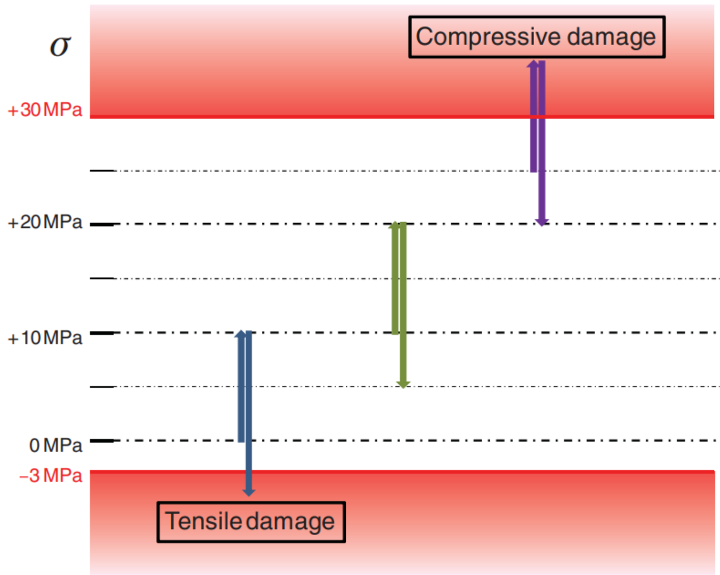


Figure 4.6: Effect of the initial state of stress in set cement (Bois et al., 2011).

4.1.5 Cement job evaluation

After a cementing job has been conducted, a cement job evaluation is performed to determine if the objectives of the cement job have been achieved. The objectives of a primary cement job vary depending on the type of casing cemented, and zonal isolation is one typical objective when cementing the intermediate and production casings. Common methods of evaluating isolation provided by the cement is pressure testing and dry testing. Pressure tests are conducted by raising the internal casing pressure until it exceeds loads that will be applied by well or drilling operations. A casing shoe that does not hold pressure indicates a poor cement job. Pressure-integrity tests (PIT) or LOTs are frequently performed on exploration wells and consists of raising the pressure until the formation breaks down (Nelson & Guillot, 2006).

Procedure for a typical PIT consists of the following:

- Check valves for leaks and prepare clean mud and a quality pressure gauge
- Perform a casing test
- Prepare a PIT graph
- Pump mud at a steady rate between 0.25 – 1 bbl/min and plot measured pressure data
- When the plot deviates from the linear trend, pump a small additional amount and stop pumping
- Monitor pressure decline for 10 - 15 minutes

Pressure graphs can give various indications. Mud channels in the cement can be indicated leak-offs below the predicted value, or a shut-in pressure that does not level off (Nelson & Guillot, 2006).

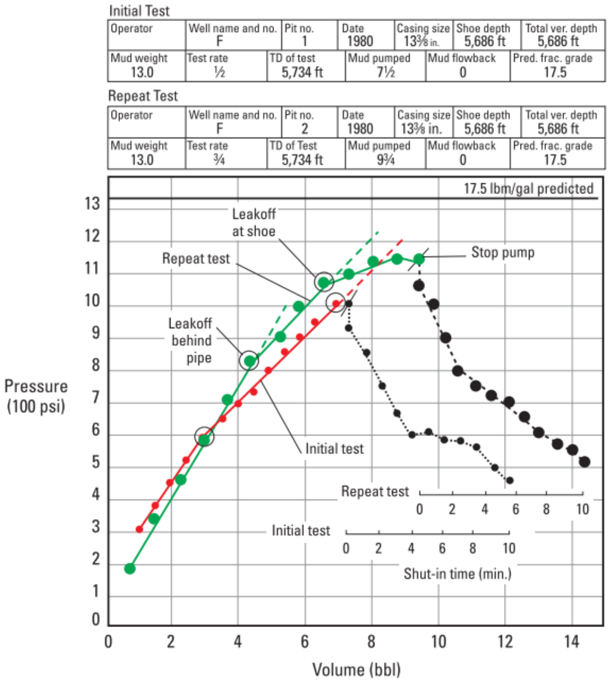


Figure 4.7: PIT graph, unsuccessful PIT test. Mud channel indicated by gradual deviation from linear trends and shut-in pressure not levelling off (Nelson & Guillot, 2006).

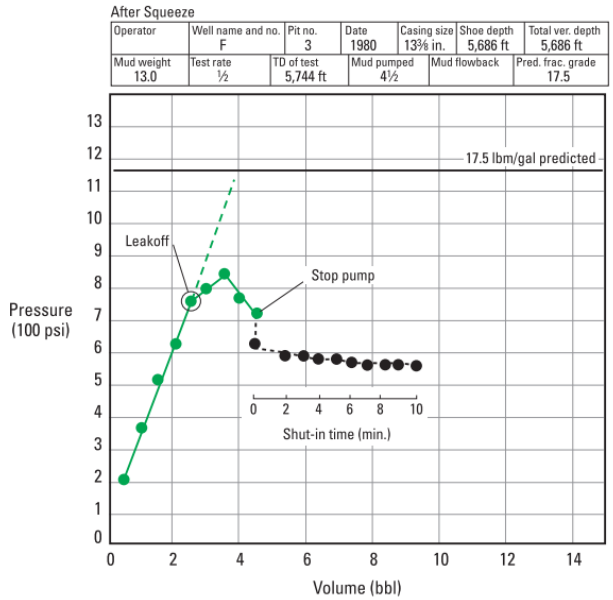


Figure 4.8: PIT graph, successful PIT test. PIT test conducted successfully after remedial cementing, leak-off at approximately 750 psi (Nelson & Guillot, 2006).

Dry testing, or inflow testing, is essentially the opposite of pressure testing. In a dry test, the pressure inside the casing is reduced, and the potential inflow of formation fluids into the well is monitored. A succesful dry test will show no change in downhole pressure during the period with reduced pressure (Nelson & Guillot, 2006).

After the completion of a well, temperature logs can indicate if the occurrence of channeling in the cement is caused by contamination by produced fluids or fluid injection outside the perforated area. Diesel can be pumped downhole to lower the wellbore temperature, and the source of the leak can thus be determined. Temperature logs are run before and shortly after the injection of diesel to determine temperature changes. Figure 4.9 shows temperature logs run in a well with a cement channel behind the casing caused by influx of formation fluid, before and after the injection of 80 bbl diesel (Nelson & Guillot, 2006).

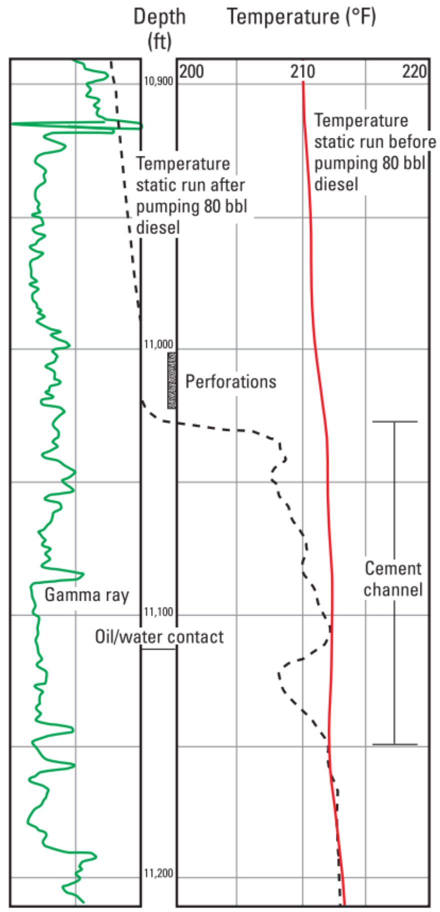


Figure 4.9: Temperature log - Cement channel containing formation fluids indicated by the large decrease in wellbore temperature above perforations post diesel injection. If the channel was caused by injected fluids, temperatures would be lower in the area of the cement channel (Nelson & Guillot, 2006).

The most widely used method of evaluating cement jobs are acoustic logs. They work by responding to the acoustic properties of the tools' surrounding environment. Typically, the tool consists of a transmitter and two receivers. Sound is transmitted and propagates through borehole materials and fluids as compressional- and shear waves, where shear waves are only able to travel through solids. Different materials have different properties when it comes to carrying sound. Properties of sound velocity and acoustic impedance are registered by the tool and used to interpret and identify materials and volumes downhole (Nelson & Guillot, 2006).

Acoustic log responses are affected by several parameters relating to the downhole environment. Detailed information concerning well geometry, formation characteristics and the cement job is therefore required to interpret the log. An accurate interpretation of the log response can only be made when the log response can be anticipated, and a cement job evaluation is made by analyzing discrepancies in the log response against the expected results. For a meaningful interpretation of the acoustic log, well data, cement job data, and pre- and post-job well history are all required, as well as a quality control of the logging tool. Acoustic logs that do not meet quality control standards have no credibility. The quality control of an acoustic log includes conducting a repeat pass of a short section of the hole immediately before the main pass. The repeat section is logged to ensure measurement repeatability between logs, and a tool that does not provide the same results under the same conditions cannot be considered accurate. For the same reason, an acoustic log must be conducted under constant conditions regarding downhole pressure and logging tool settings (Nelson & Guillot, 2006).

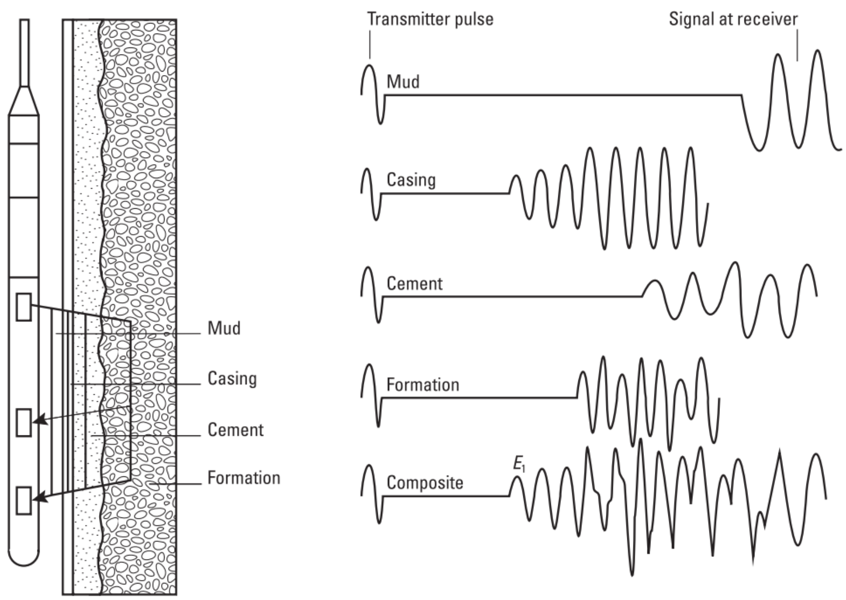


Figure 4.10: CBL tool and waveforms

Left: Representation of paths acoustic energies can take before arriving at the receivers.

Right: Waveforms and relative times of arrival at receiver illustrated (Nelson & Guillot, 2006).

A representation of a conventional bond logging (CBL) tool and different paths acoustic energies can take before arriving at the receivers is given in Figure 4.10. The wave refracted directly down the casing wall usually arrives at the receiver first due to the short distance and high sound velocity in steel. The wave travelling through mud has an even shorter path but will arrive later due to the low sound velocity in mud. Waveforms and relative times of arrival are also illustrated in Figure 4.10. The casing wave loses energy to the annulus and borehole walls as it propagates due to the casings' shear coupling with adjacent materials.

Stronger shear couplings will result in greater energy loss. The loss of energy to the formation is low and constant, therefore the loss to the annulus is the variable. If the annulus is filled with fluid, little energy will be lost from the casing signal due to shear waves inability to travel in fluids, and thus all fluids are expected to give the same signal. For this reason, microannuli between casing and cement of only a few micrometers can have a significant impact on the signal (Nelson & Guillot, 2006).

A variable-density log (VDL) is commonly used for bond logs because it presents all available information in picture form. Waveform amplitudes from the VDL log is typically presented as a grayscale or color-spectrum chart called a variable intensity display. In the color display, negative amplitudes are displayed as dark blue, maximum amplitude is displayed as red, and zero-amplitudes are displayed as red.

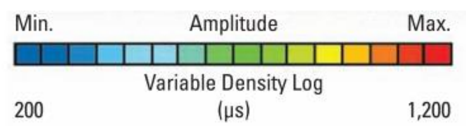


Figure 4.11: Amplitudes and respective colors of a VDL (Nelson & Guillot, 2006).

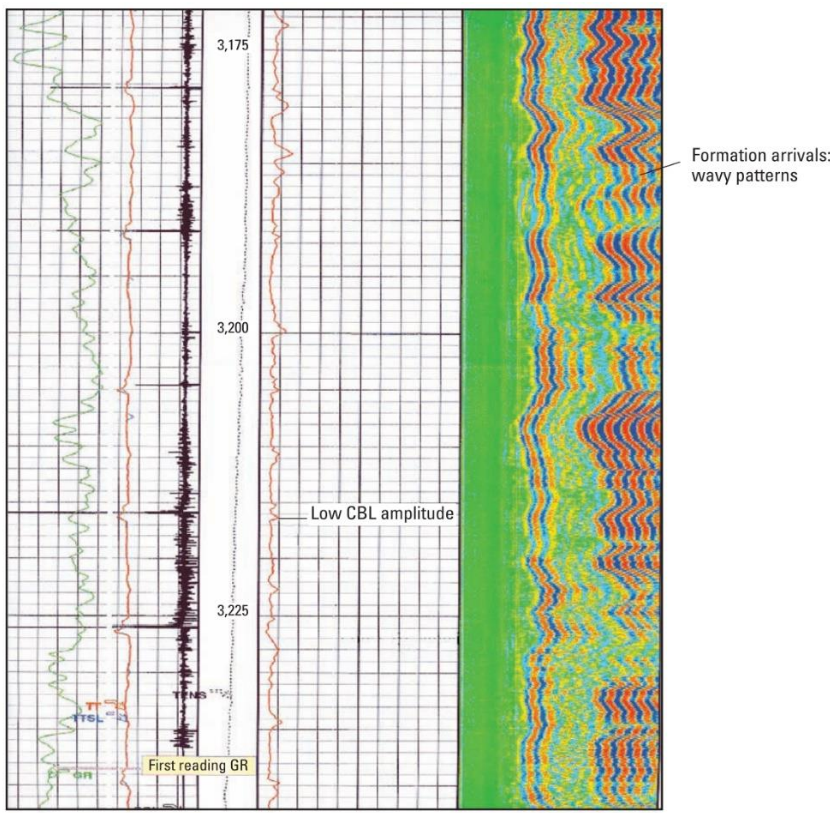


Figure 4.12: Full acoustic wave display – CBL and VDL displayed together. Absence of casing arrival and low CBL amplitude indicates good acoustic coupling between casing, cement, and formation (Nelson & Guillot, 2006).

Analysis of the full acoustic wave display will give qualitative information about the cement job. If intergranular contact is maintained between casing and cement, most of the energy will propagate into the cement. A low CBL amplitude is therefore an indication that no microannulus is present. Similarly, if intergranular contact is maintained between the cement sheath and formation, the energy will propagate into the formation. An example of good acoustic coupling between casing, cement and formation is illustrated in the Figure 4.12. Acoustic properties of formations will usually vary as they are rarely perfectly homogenous, as illustrated by the wavy lines in the full acoustic wave display (Nelson & Guillot, 2006).

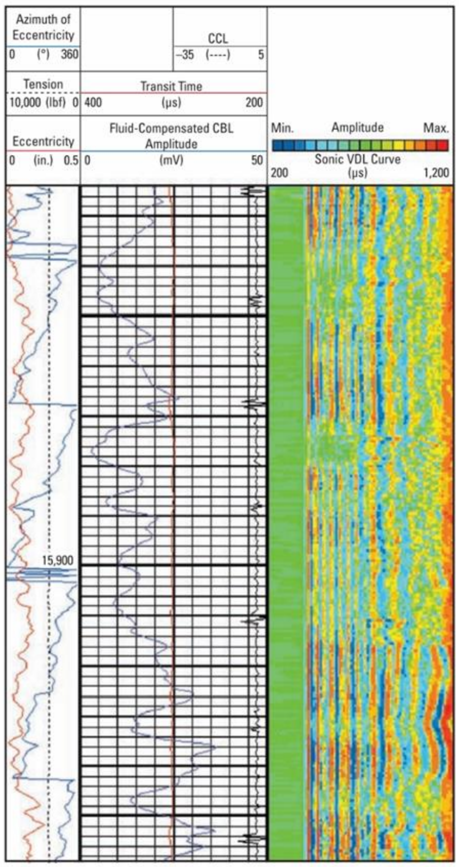


Figure 4.13: Effect of microannulus on CBL/VDL (Nelson & Guillot, 2006).

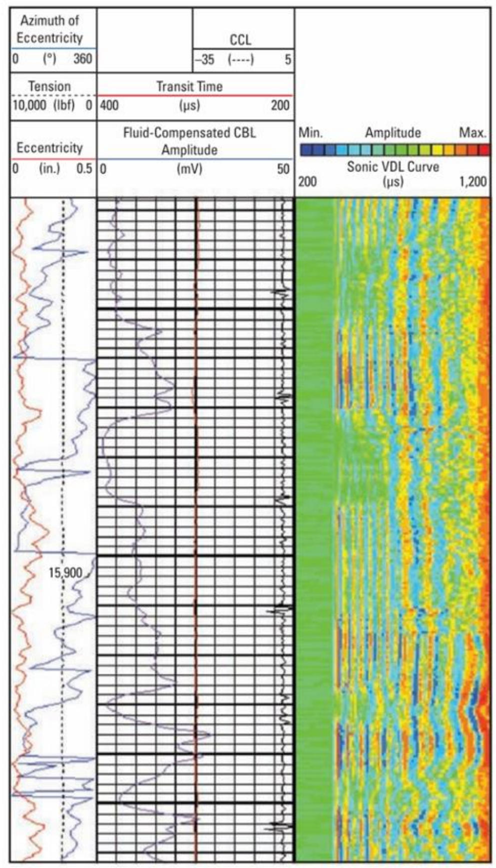


Figure 4.14: Effect of applied pressure on CBL/VDL (Nelson & Guillot, 2006).

The effect of a microannulus on a CBL is illustrated in Figure 4.13. The pipe signals are visible at the early time as a distinct, green column in the left of the VDL display. Wavy bands indicating the formation signals also occur at a later time, in the right of the VDL display. Furthermore, CBL amplitude (illustrated by the blue line) is erratic and at moderate values. These are all indications that a poor acoustic coupling is present. Figure 4.14 is a second log pass over the same interval of the well after a pressure of 1500 psi has been applied at the surface. The color contrasts indicating pipe signal has been significantly reduced as can be seen by the less distinct, green column in the left of the VDL display. CBL amplitudes have also reduced to lower values, giving the indication of improved acoustic coupling. In this particular example, the pressure increase of 1500 psi caused an expansion of 20 μm to the casing radius.

A limitation of traditional cement bond logs is therefore having to pressurize the casing to confirm the presence of a microannulus. If CBL amplitudes are not improved by the pressure increase, channels might be present in the cement, or they can be caused by a larger microannulus. Both occurrences will produce strong casing signals and late formation arrivals, like displayed in Figure 4.13 (Nelson & Guillot, 2006). For these reasons, the presence of "good bond" on a CBL is in fact not an indication of bond, but of good acoustic coupling which is achieved by intergranular contact between casing and cement, maintained by sufficient radial pressure (Dusseault, Gray & Nawrocki, 2000).

4.2 Defective Well Construction

Well construction is a comprehensive process with a lot of moving parts, all critical for ensuring well integrity and proper zonal isolation. This chapter outlines mechanisms that can create leakage paths and lead to SCP as a result of defective well construction.

Thread Leaks

As described in Chapter 4.1, casing sections are fitted together with threaded connections and torqued to spec as the casing is lowered in the borehole. Proper design of connections based on mechanical loads, pressure and temperature is critical for casing integrity. During well assembly thread compound is applied to the casing threads. Thread compounds are integral to sealing the connection but is often applied by rig workers with limited experience, and connections are rarely tested while running the casing (NRCan, 2019). Defective casing connections can cause leak paths through the threads in these connections (Bois et al., 2011). Although not specified if caused by thread leaks or other casing related problems, the 2006 PSA Well Integrity Survey found that 8 of the 406 wells surveyed had integrity issues attributed to casings (Vignes et al., 2006).

Improper Mud Misplacement

Prior to cementing, residual mud used during the drilling process must be displaced from the wellbore annulus. Drilling fluids may inhibit the proper curing of cement, and filter cake caught on the wellbore walls may provide a poor bond between the cement and the wellbore. A low viscosity spacer fluid is therefore circulated through the wellbore to remove mud and filter cake, like described in Chapter 4.1. Improper hole conditioning and poor mud displacement can lead to micro-annuli between cement and borehole, mud channels in cement and compromised cement properties (NRCan, 2019, Watson, Getzlaf & Griffith, 2002).

Figure: Ineffective mud displacement resulting in fluid channels. Gels in the drilling fluid have shrunk over time and provided flow paths for gas in the annulus (Watson et al., 2002).

Microannulus Formation due to Cement Shrinkage Caused by Water Loss

If cement is designed or placed with a too high water content at too high hydrostatic pressure, water can be lost to formations at lower pore pressures causing a slightly reduced volume of cement. Because the annular space between formation rock and casing is small (12 1/4” (311 mm) holes are typically drilled for the 9 5/8” (245 mm) production casing, resulting in a 33 mm width of the annular space on either side of the casing), the development of only a small shear strength between formation rock and cement is sufficient to support the weight of the cement. A cement to rock bond with a shear strength as low as ~0.5 kPa can support the entire “hydrostatic head” of the cement column. It should be noted that due to temperature and pressure effects, cement setting will not occur simultaneously for the entire cement column. However, at some point in the cement setting state, the cement can no longer be considered a liquid and the ability to compensate for water loss by settling downwards - like a liquid - will be inhibited by shear stress transfer to the formation rock. The result is then a cement sheath that has shrunk due to water loss and set before water loss can be compensated by hydrostatic pressure. This phenomenon combined with the autogenous shrinkage during hydration could cause a large microannulus to form (Dusseault et al., 2000).

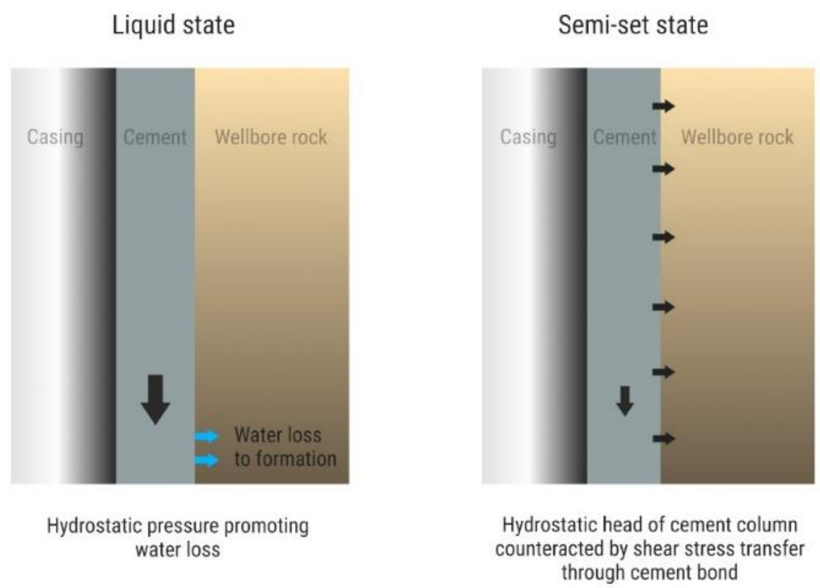


Figure 4.15: Water loss to formation. Figure based on Dusseault et al. (2000).

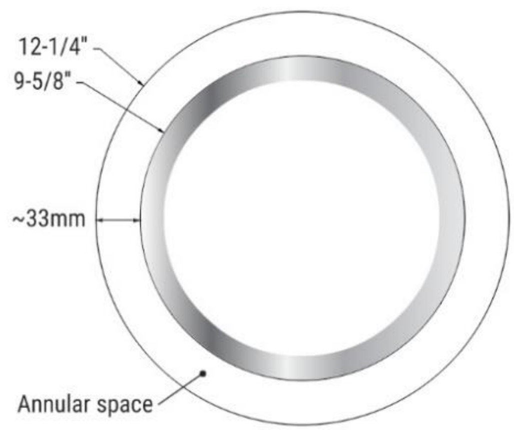


Figure 4.16: 9-5/8” casing in 12-1/4” hole

Low Cement Top

Uncemented sections of the annulus are a significant cause of SCP and casing failure due to casing corrosion. One characteristic of cement is the ability of isolating the casing from corrosive elements. Low cement tops might not cause immediate concerns for well integrity, but over time the corrosion could lead to wall thinning and reduced burst and collapse pressures in casings (NRCan, 2019). Unintended low cement tops can result from lost circulation or an underestimated annular volume. While in the liquid state, the cement column will provide a hydrostatic pressure acting on the formation as a function of cement density and column height (Nelson & Guillot, 2006). Formation fracturing pressures are considered in the design of the cement column and wells might be designed with low cement tops due to the inability of deeper formations to withstand the pressure provided by a full cement column. Lost circulation can occur if the formation fracturing pressure is exceeded for one or more zones by excessive cement density, leading to no cement returns at surface. In case of borehole washouts, the borehole size can exceed the measuring capability of caliper tools and accurate hole volumes can be unobtainable (Nelson & Guillot, 2006). Economic considerations might also play a role for wells with a designed low cement top (NRCan, 2019).

Formation Fluid Influx in Cement

When designing a cement slurry, a cement density is chosen such that the hydrostatic pressure provided by the cement column is higher than that of the target reservoir, creating an overbalance. Water loss is promoted when pore pressure in the reservoir is exceeded, creating a high density slurry with no fluids entering the cement column during setting. However, if the reservoir pressure is higher than that provided by the cement column gas or fluid can migrate into the cement creating channels. Hydrostatic pressure decreases during the setting process as the cement bonds to the borehole walls. Cement may initially be placed with a sufficient hydrostatic pressure, but as the cement sets this pressure is reduced. If this happens before the cement has developed sufficient strength, channels can form in the cement column leading to leakage paths (NRCan, 2019, Watson et al., 2002).

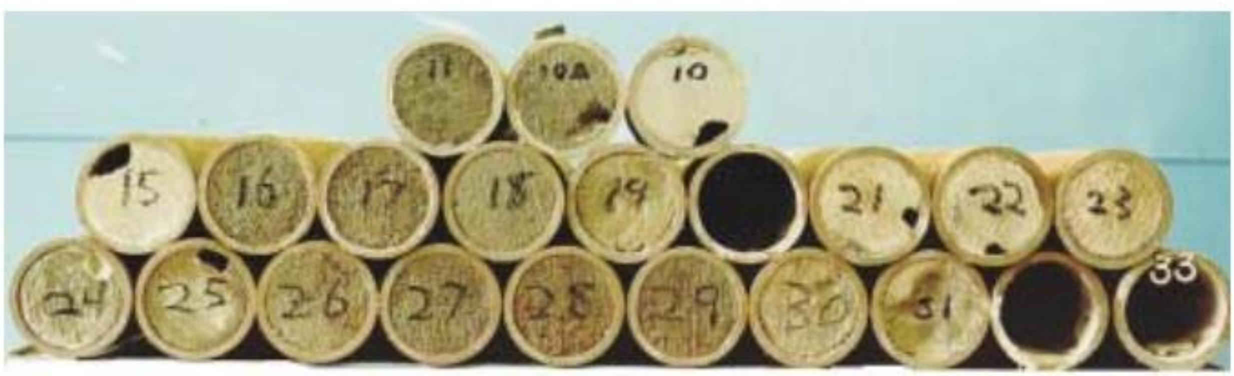


Figure 4.17: Gas channels in cement due to gas migration before cement has fully set (Watson et al., 2002)

Microannulus Formation due to High Density Displacement Fluid

Displacing the cement with the same fluid also used for further drilling is not an uncommon practice (NRCan, 2019). This saves the operator having to circulate out displacement fluids, cutting time and cost. The cement is displaced with a high density drilling fluid, which is left in the casing while the cement sets. After cement has set the fluid is then used for drilling deeper sections. However, when there is a high difference is density - and thus pressure - between the inside and outside of the casing, a ballooning effect can happen. The density differences can cause the cement to set while the casing is expanded, creating a micro-annulus at the cement sheath inner interface when the pressure is reduced, and the casing retracts. Thin-walled casings suffer more from this phenomenon than do thick-walled, and the problem usually occurs in deeper wells where a high mud density is required for drilling through high pressure formations (NRCan, 2019).

Microannulus Formation due to Cement Hydration

The cement hydration process is an exothermal process. Heat is produced and temperatures increase at the beginning of the hydration process while the cement is flexible and has a high thermal expansion coefficient. In the later stages of hydration, temperatures decrease while the thermal expansion coefficient is low, and the cement has developed rigidity similar to that of set cement. Studies have shown this can favor a microannulus opening at the cement sheath inner interface (Bois et al., 2011). Furthermore, cement hydration occurs as an increase in grain size, similar to that of a temperature increase (although not followed by a temperature decrease) where the thermal expansion coefficient of the casing is none. This would also favor the creation of a microannulus at the cement sheath inner interface. Other factors relating to the hydration process that can facilitate the creation of a microannulus include cement systems that produce a lot of heat during hydration, thick cement sheaths leading to increased heat production and cement sheaths located in front of contracting, unconsolidated formations (Bois et al., 2011).

Conducting Well Operations Prior to Adequate Cement Setting

As described in Chapter 4.1,well equipment is installed on top of the surface casing after it has been cemented. If done before necessary compressive strength has developed in the cement this can cause casing movement and may develop a microannulus (NRCan, 2019). Pressure tests conducted before necessary compressive strength has developed in the cement might cause the same ballooning effect as for high density displacement fluids described in the chapter above, causing expansion of the casing during cement setting and microannulus development (Bois et al., 2011). Thin-walled casings are again more susceptible to this effect. Because cement setting time is highly dependent on temperature, determining the necessary setting time and compressive strength can be complicated for long cement intervals with high temperature differentials between top and bottom of the interval (NRCan, 2019).

Poor Casing Centralization

As illustrated in Figure 4.16, the annular space between casing and borehole is relatively small. Eccentric casing placement prohibits effective mud displacement and filter cake removal, like described in chapter 4.1.2, and uniform cement slurry placement. This leads to an increased probability of leakage paths (NRCan, 2019, Dussealt, Jackson & MacDonald, 2014). Casing centralizers are typically fitted at casing joints in intervals of one centralizer per 100m for vertical wells, although intervals vary by different companies and wellbores. Casing centralization is especially an issue for deviated and horizontal wells (Dussealt et al., 2014). A 2009 study on wells in Alberta, Canada, found that SCVF and gas migration occurred at a higher rate for deviated wells than for vertical wells, with poor casing centralization suspected as the main contributing factor to this (Watson & Bachu, 2007). A report by Dusseault er al. (2014) on wellbore leakage in Canada concluded that ensuring adequate casing centralization might be the most cost effective way of improving the wellbore leakage occurrences.

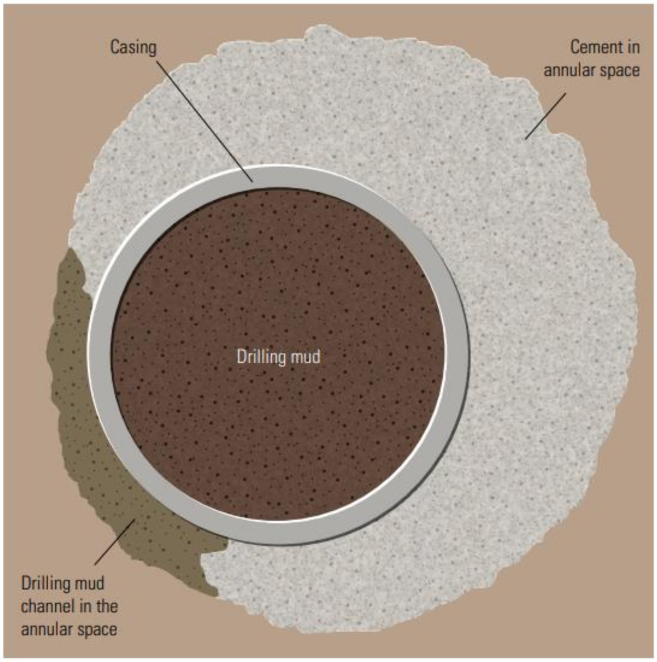


Figure 4.18: Off-centered casing placement – Cement flows through the larger pathways of least resistance, leaving a mud channel (Docherty et al., 2016).

4.3 Post Completion Defects

Post-completion defects are associated with wear and mechanical stresses on well components during operations. They occur some time after the well is completed but might be accelerated due to factors relating to well completion.

Microannulus Formation Due to Pressure Variations in the Wellbore

During production, the well is circulated with fluids of different densities. Hydrostatic pressure variations can occur when a mud is replaced by a fluid of a different density. Differences in pressure can cause repeated expansions and contractions in casings and cement sheaths. These movements can cause cement de-bonding from the casing and cement cracking leading to leakage paths (Bois et al., 2011, Watson et al., 2002).

Experiments have repeatedly shown that a large decrease in casing pressure tends to increase cement sheath permeability, possibly by creation of a microannulus at the cement sheath inner interface. Similarly, an increase in casing pressure tends to decrease the cement sheath permeability.

One experiment by Jackson and Murphy (1993) (Bois et al., 2011) was conducted as follows:

1) Cement is pumped into the annulus formed by a 5’’ and 7’’ casing. 1 000 psi is applied to the inner casing and the cement is left to set for 69 hours.
2) Annulus pressure is bled off and a 100 psi source of air is fitted to the bottom of the annulus.
3) Inner casing pressure is increased to 2 000 psi and cement sheath permeability to gas is measured.
4) Inner casing pressure is decreased to 1 000 psi and cement sheath permeability to gas is measured.
5) Steps 3 and 4 is repeated in 2 000 psi increments up to 10 000 psi inner casing pressure.

The following observations was made in the test:

- No leakage was detected after the 100 psi source of air was fitted to the bottom of the annulus.
- No leakage was detected throughout the 2 000-, 4 000-, and 6 000 psi pressure cycles.
- Gas started to flow as the inner casing pressure was decreased from 8 000 to 1 000 psi. This flow continued until the inner casing pressure was increased back to 1 900 psi. No further flow was detected at or above 1 900 psi.
- Gas started to flow as the inner casing pressure was decreased from 10 000 to 1 000 psi. This flow continued until the inner casing pressure was increased back to 2 800 psi. No further flow was detected at or above 2 800 psi.

Similar experiments have been conducted and provided similar results. One experiment by Boukhelifa (2005) (Bois et al., 2011) showed that the inner casing pressure at which a microannulus was opened was higher if the casing had previously been subjected to a loading cycle, meaning the creation of a microannulus was easier after a loading cycle such as a LOT had been performed.

Microannulus Formation due to Stress Variations in the Formation

Stress variations can occur in the formation when reservoirs are pressurized or depressurized. Mathematical modeling of radial stress decreases in formations have found that pore pressure within the cement sheath remain constant, radial effective stress variations in the cement sheath are tensile, and the largest variation in radial effective stress occurs at the cement sheath outer interface. Research also shows that cement sheaths made from flexible cement systems exhibit lower radial stress variations than that made with rigid cement systems. These findings would suggest a decrease in formation pressure could favor the creation of a microannulus at the cement sheath outer interface. Similar to increases in casing pressure, formation pressure increases would prevent the creation of a microannulus at both cement sheath interfaces (Bois et al., 2011).

Microannulus Formation due to Temperature Cycles in the Wellbore

Temperature fluctuations occur when fluids of different temperatures are circulated in the wellbore. As an example, this can occur when a steam injection well is killed by injecting cold water. Mathematical modeling show that, in the short term, large temperature differences can occur in a cement sheath located between two casings, radial stress variations in the cement sheath are tensile, the largest radial stress variation occurs at the cement sheath inner interface, cement sheaths made with flexible cement systems exhibit lower radial stress variations than that made with rigid cement systems and cement sheaths placed against deformable formations exhibits lower radial stress variations than those placed against more rigid formations (Bois et al., 2011).

Figure 4.19 illustrates temperature variations in a cement sheath during a killing operation. In this case, the killing operation consisted of injecting 20˚C water at 8 bbl/min after several months of steam injection at over 200˚C. The wellbore consisted of a 16” and a 11 ¾” casing in a 20” hole. The reference state is temperatures before steam injection. The horizontal axis denotes radius with “0” being the inner casing and “2” being the cement – formation interface. Different symbols denote different depths in the casing. As can be seen, temperature variations increase from 0˚C at the inner casing to 190˚C at the outer casing. Temperature variation decrease to 170˚C at the cement – formation interface (Bois et al., 2011).

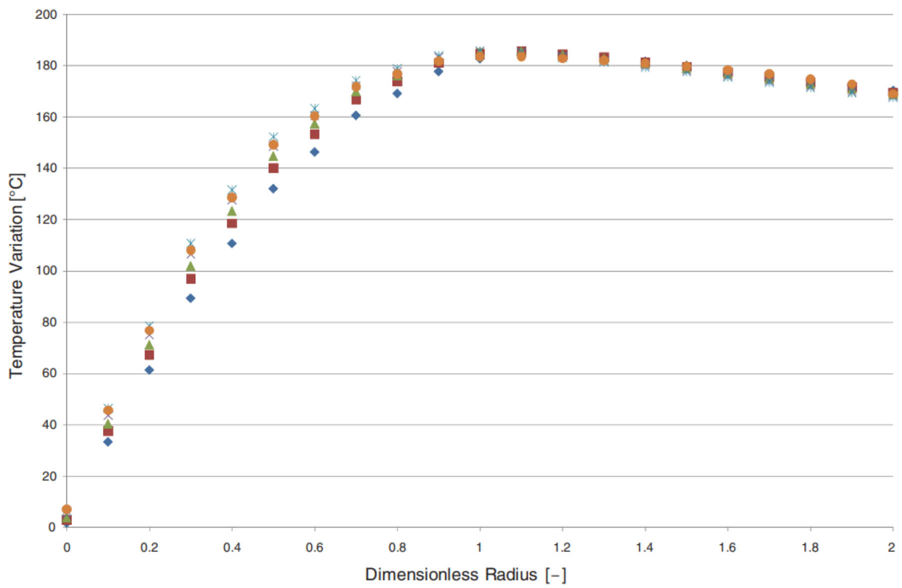


Figure 4.19: Temperature variations in a steam injector well at the beginning of a killing operaton. Radius of “0” denotes the inner casing, radius of “2” denotes the cement – formation interface. Different symbols denote different depths in the well (Bois et al., 2011).

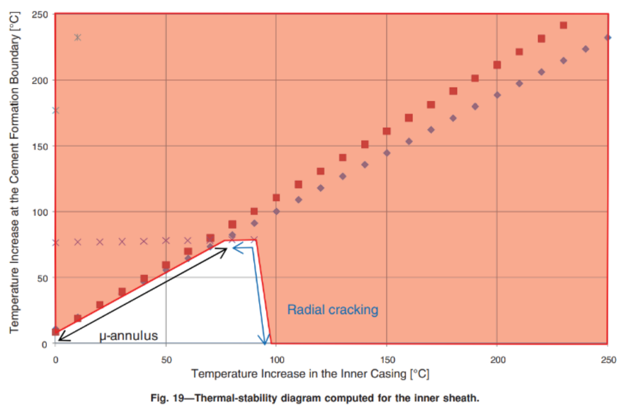


Figure 4.20: Thermal stability diagram for inner sheath (Bois et al., 2011).

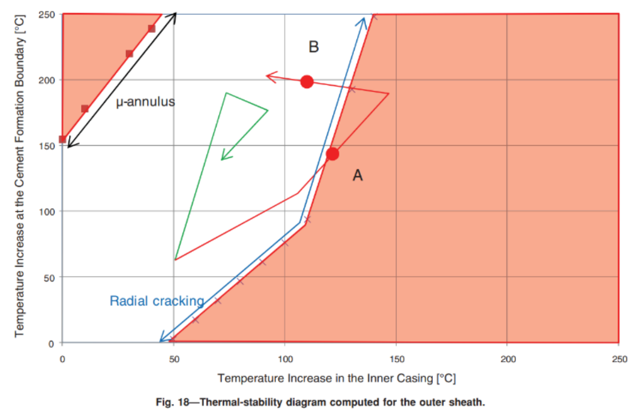


Figure 4.21: Thermal stability diagram for outer sheath (Bois et al., 2011).

Figures 4.20 and 4.21 show thermal stability diagrams computed for the inner and out cement sheaths respectively. The horizontal axis represents temperature variations at the inner casing, the vertical axis represents temperature variations at the cement – formation interface. The white areas illustrate temperature variation envelopes in which the cement remains undamaged. As can be seen in Figure 4.20, the configuration for the inner cement sheath is very small. Even though using a resilient cement could enlarge it somewhat, it would still remain so small that in order to avoid causing damage, temperatures would have to be lowered at an operationally unfeasible rate. The figures show that the cement sheath bounded by a casing and the formation has a much larger operational zone that will not result in damage. For the outer cement sheath, if temperature variations occur according to the green line in Figure 4.21, the cement sheath will remain undamaged, but if allowed to reach outside the bounded area, for example to Point A, damage will be caused even if temperature paths enter back into the bounded area, such as going to point B. For temperature variations occurring according to the path described by the red line in Figure 4.21 radial cracks would occur in the cement sheath (Bois et al., 2011).

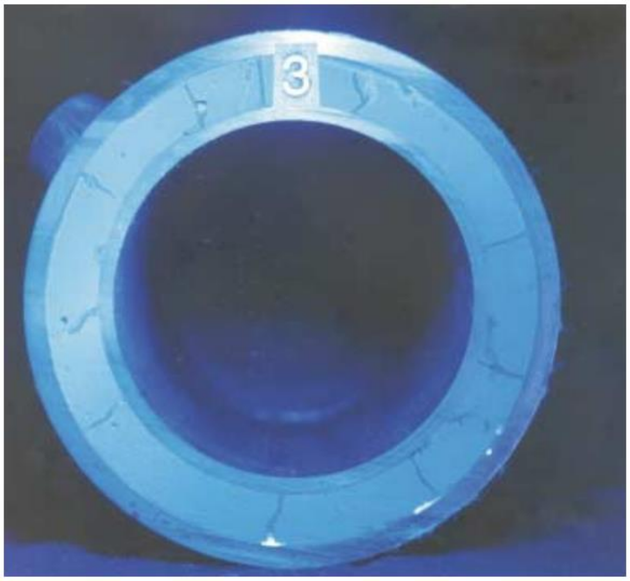


Figure 4.22: Radial cracks in cement sheath (Watson et al., 2002).

Leaks due to Corroded Production Tubing

Leaks in the production tubing typically occur due to poorly fitted thread connections, corrosion, erosion, or a combination of the three. Corrosion occurs due to production of corrosive elements such as CO_2, H_2S and saline water but can also be caused by incompatibility between tubing material and injection water quality (Smith, 1999). An example of the latter is illustrated in Figure 4.24. H_2S is a highly corrosive material which in contact with metallic materials produce hydrogen, and the process can lead to severe degradation of metals through hydrogen induced embrittlement and cracking. Typically, small leaks start at the threaded connections and develop due to corrosion or erosion. Particles contained in the produced fluids, such as sand, can erode the production tubing and ultimately cause large holes. As fluid carrying particles passes through a leakage path, the metal is slowly eroded leading to larger leakage paths that can carry even larger amounts of fluid, and the erosion rate therefore increases. PSA’s 2006 Well Integrity Study found that production tubing was the dominating failure component. Leakages in production tubing will typically cause SCP in the A-annulus at the production casing (NOROG, 2012, Smith, 1999).

Figure 4.23: Large hole in production tubing – The leak has started at the connection and likely developed due to both corrosion and erosion (NOROG, 2012).

Figure 4.24: Corroded tubing due to material incompatibility with injection water (NOROG, 2012).

5 Diagnosis

Detection of SCP is done by monitoring annulus pressures and pressure trends. During normal operations, annulus pressures will show clear and predicable patterns based on well temperatures and operations. As discussed in earlier chapters, clear regulations and guidelines exist to aid in the early detection and assessment of pressure build-ups. However, diagnosis of mechanisms leading to pressure build-ups once SCP has been confirmed is not as clearly defined. Understanding the source and mechanism of the leak is essential for effective remediation. This chapter aims to present methods for effective diagnosis.
Typically, the first step in a leak mechanism evaluation is systematic manipulation of annular pressures by applying or bleeding off pressures in the different annuli. Communication between adjacent annuli can be detected by dependencies between pressures. Similarly, leak directions can be investigated between adjacent annuli. Well construction diagrams and well barrier schematics should be evaluated to identify potential leak paths, as well as historical data on well interventions and monitoring. Lithology and pore pressure data should be assessed to identify possible sources. Analysis of fluids bled off from the annulus should also be performed and can provide insights into possible sources. If an adequate evaluation cannot be made by these approaches, logging methods like described in Chapter 4.1.5 are required.

5.1 Noise Logging

Gas, water, and oil produce sound while flowing. Noise logs can therefore be used to detect and locate fluid flow behind the casing. The technique can be particularly useful in identifying communication between zones of different pressure near the wellbore. Frequencies produced during fluid flow range from 20 to 50 000 Hz, and analysis of the frequency spectrum can identify medium and magnitude of the flow.

The logging method consists of a series of stationary noise measurements in the wellbore due to the difficulty of detecting formation related sounds while the tool moves continuously. For this reason, the logging method is rarely used in cement job evaluations. However, for identifying depth and magnitude of flow in a channel, fracture or microannulus behind the casing, the tool can prove useful for aiding in SCP diagnosis (Nelson & Guillot, 2006).

5.2 Pressure Build-up Modelling

This chapter describes a mathematical model of SCP build-up in an annulus with a mud column above the cement top was developed in 2001 by researchers Xu and Wojtanowicz (2001). The objective was identifying flow mechanisms of the leak leading to SCP. The model can determine some critical parameters to be used in selecting remediation methods.

The model assumes gas migration as a function of time steps. The pressure at the cement top is constant at a given time step, giving a constant flow rate over the duration of a step. Gas released at the cement top during one step migrates through the mud column and accumulates in the gas cap at the casing head during the next step. This is based on the assumption of gas migration time being shorter than the time steps, and valid for high gas rise velocities. The time steps are therefore small. Representing transient gas flow as a series of steady-state flow periods would otherwise be invalid. However, for a short mud column of low viscosity, the time taken for gas to reach the top would be very short. A reasonable time step is therefore set to make this assumption valid. Because formation permeability is to gas is high when compared to that of cement, formation pressure is assumed constant. Mud is assumed a slightly compressible fluid with constant density. Temperatures at the top of the cement and at the top of the mud are different and known. Based on these assumptions, casing pressure (pressure at the wellhead) p_t at the n-th time step can be computed as:

$$p_t^n = \frac{1}{2}\left(p_t^{n-1} - \frac{V_t^{n-1}}{c_m V_m^{n-1}} + \sqrt{\left(p_t^{n-1} - \frac{V_t^{n-1}}{c_m V_m^{n-1}}\right)^2 + \frac{4T_{wh}\sum_{k=1}^{n} p_c^k q_c^k \Delta t}{c_m V_v^{n-1} T_{wb}}}\right) \qquad (1)$$

Pressure at the top of the cement p_c can be related to surface casing pressure by:

$$p_c^n = p_t^{n-1} + 0.052\rho_m L_f^{n-1} \qquad (2)$$

Steady state flow rate at the top of the cement is:

$$q_c^n = \frac{0.003164 k T_{sc} A}{p_{sc} T L_c \mu_i Z_i}\left[p_f^2 - (p_c^n)^2\right] \qquad (3)$$

Symbol	Definition	Unit
A	area of annulus, L^2	ft^2
c_m	mud compressibility, Lt^2/m	psi^{-1}
D_1	outer diameter of annulus, L	in
D_2	inner diameter of annulus, L	in
k	cement permeability to gas, L^2	md
L_c	length of cement column, L	ft
L_t	length of gas chamber, L	ft
L_f	length of mud column, L	ft
p_c	pressure at the top of cement, m/Lt^2	psia
p_f	gas source formation pressure, m/Lt^2	psia
p_t	pressure on surface, m/Lt^2	psia
q_c	flow rate at the top of cement, SCF/D	SCF/D
T	reservoir condition temperature	K
T_{wb}	average wellbore temperature	K
T_{wh}	wellhead temperature	K
V_m	volume of mud column, L^3	ft^3
V_t	volume of gas chamber, L^3	ft^3
Z	gas-law deviation factor	
μ_g	gas viscosity, m/Lt	cp
ρ_m	density of mud in the wellbore, m/L^3	lb/gal
Δt	time step, t	day

Table 5.1: Quantities used in Xu & Wojtanowicz’ (2001) model.

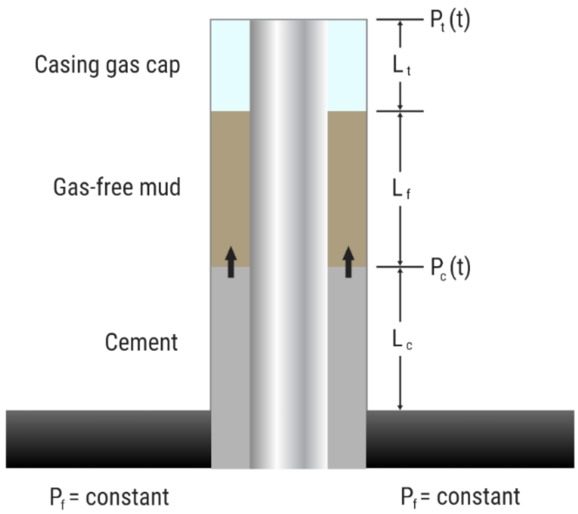


Figure 5.1: Process of gas migration in the cement and mud column illustrated (Xu & Wojtanowicz, 2001).

Effect of parameters on SCP build-up

The model was used to analyze the effects of parameters controlling the pressure build-up. The parameters are mud compressibility, formation pressure, size of gas cap above the mud and cement permeability. Analysis of the effects can be useful to identify input data needed for meaningful testing.

Effect of casing gas cap

The gas cap is located at the top of the casing annulus and is usually filled with gas or heavily gas-cut mud. Gas caps of different sizes were plotted in the model to determine its effect on SCP build-up patterns. The gas cap has a cushioning effect on pressure build-up due to the large differences in compressibility of gas and mud, meaning a larger gas cap will lead to a slower pressure build-up. The time needed before pressure starts to stabilize increases with increasing gas cap size, and therefore a longer testing time is required. At the same time, a larger gas cap would mean a smaller mud column, which would decrease the hydrostatic mud pressure and lead to more gas migrating after a pressure bleed-off. Inversely, reducing the size of the gas cap by filling the annulus with mud would lead to shorter pressure build-ups and more effective diagnosis.

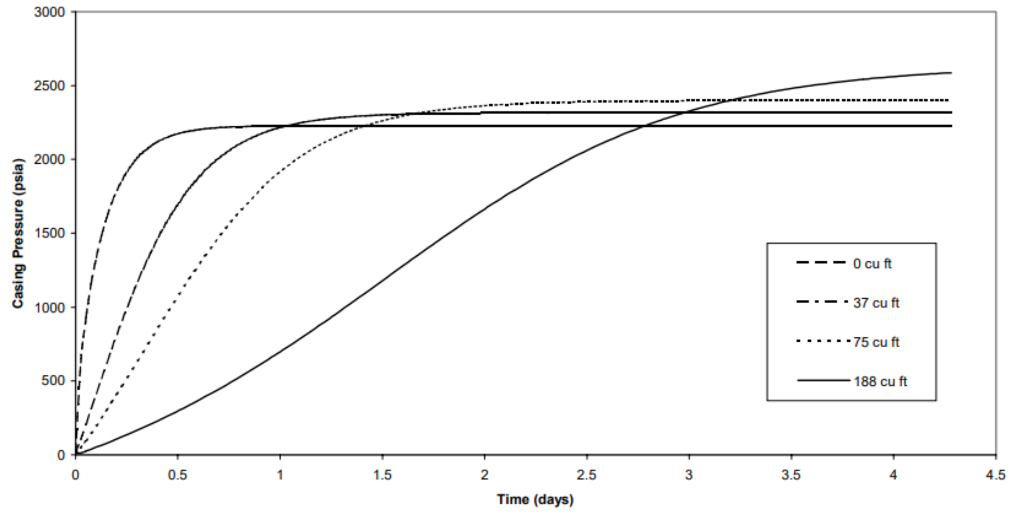


Figure 5.2: Effects of casing gas cap size on pressure build-up times. Large casing gas caps slows down the rate of pressure build-up.

Effect of mud compressibility

The effect of mud compressibility was also tested in the study. Higher mud compressibility leads to an increased time before pressures stabilize due to mud volumes compressing, which effectively creates a larger gas cap. Therefore, filling the annulus with a thin, gas-free liquid would improve testing times.

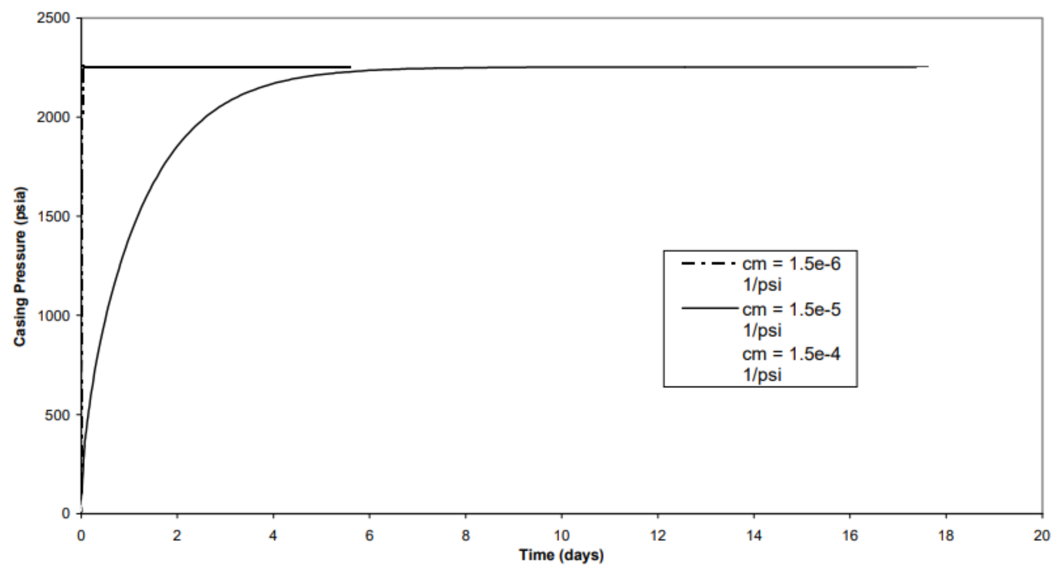


Figure 5.3: Effects of mud compressibility on pressure build-up times. Less compressible mud increases the rate of pressure build-up.

Effect of cement permeability

The model uses "cement permeability to gas" to represent cement quality. The study found that early stages of pressure build-ups were highly sensitive to this parameter, which can be seen in Figure 5.3. Reducing the cement permeability to gas from 5 μd to 0.5 μd lead to an increase in time before pressures at the wellhead stabilized from 3 to 80 months. Furthermore, obtaining the permeability of cement in a real well is difficult. The model can therefore be used to estimate the permeability and aid the assessment of cement quality.

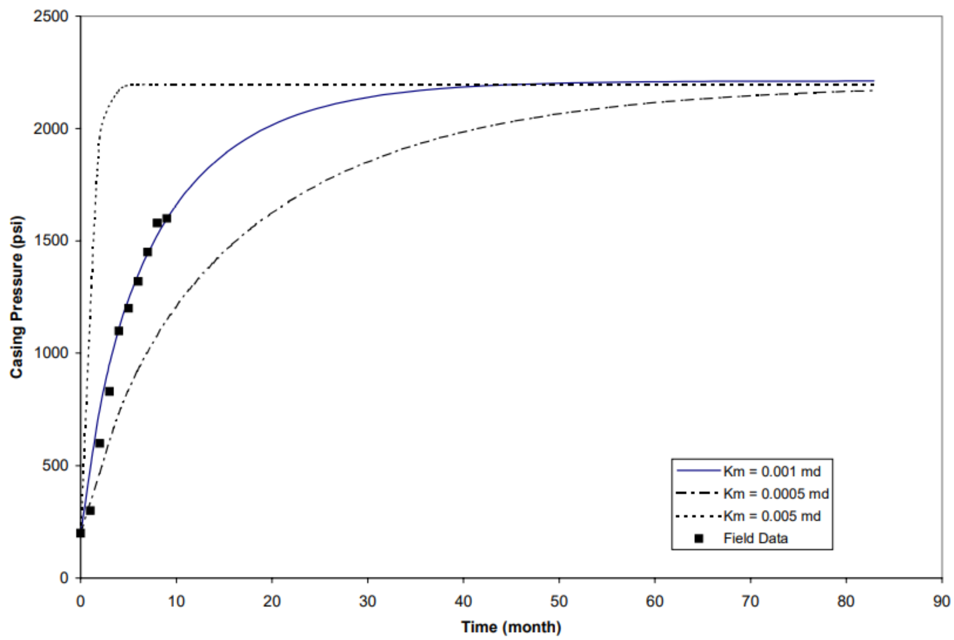


Figure 5.4: Effects of cement permeability (cement quality) on pressure build-ups. Lower permeability leads to longer build-up times.

Effect of formation pressure

During pressure build-up, formation pressure stays relatively constant due to formation permeability to gas being much higher than that of cement. Formation pressure therefore affects the stabilized pressure, and higher formation pressures lead to higher stabilized pressures.

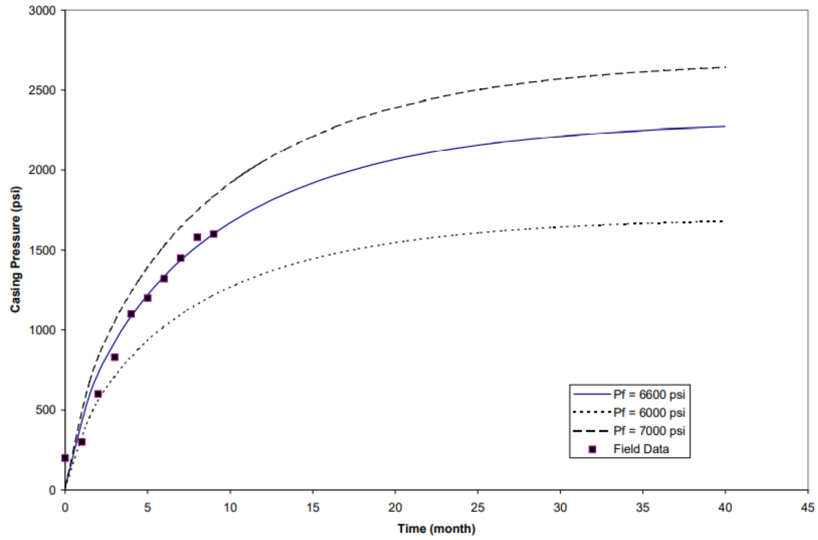
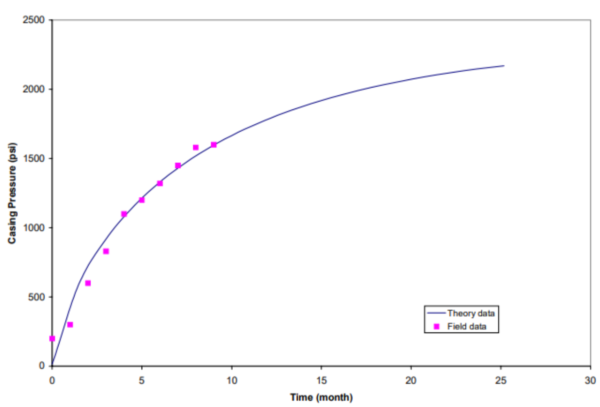


Figure 5.5: Effects of formation pressure on pressure build-up. Higher formation pressures lead to higher stabilized pressures.

Determining uncertain well parameters

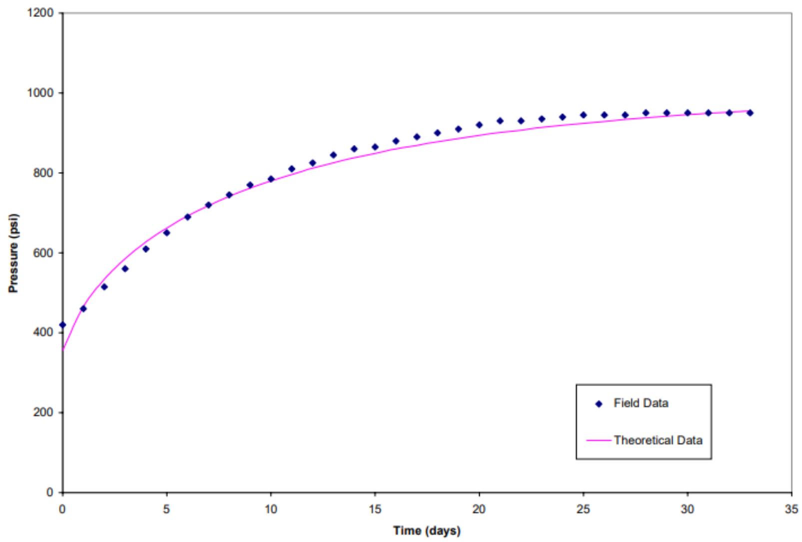
Matching the model to field data show that uncertain well parameters can be estimated. “Well 23” was a gas producing well exhibiting SCP in the intermediate casing. Pressure had increased from 200 to 1 600 psi in 8 months. Matching theoretical data to field data indicated that this pressure build-up resulted from a 6 600 psia source formation. The model also estimated that the pressure build-up would stabilize after 25 months at 2 170 psi casing pressure. The estimated cement permeability to gas for the modeled build-up was very low, at 0.001 md. However, this value is not unrealistic when compared to laboratory tests of well-cured cements.



		Well 23
T_{wb}	K	575
T	K	630
T_{wh}	K	520
D_1	in	9.95
D_2	in	7
L_c	ft	1821
Initial L_f	ft	8273
Initial L_t	ft	27
μ_g	cp	0.02
P_{sc}	psia	14.7
c_m	psi^{-1}	4.0e-6
ρ_m	ppg	10
Z		0.86

Figure 5.6: Estimated pressure build-up compared to field data in “Well 23”.

“Well 24” also exhibited SCP in the intermediate casing. The casing pressure had reached 1 000 psia in one month and was frequently bled off. Heavier mud was pumped into the annulus after each bleed-off, and volumes of bled and pumped muds was recorded. No mud was bled or pumped during the build-up period. Several assumptions were made due to some input data lacking, but estimated patterns show good correlation with field data. Source formation pressure was estimated at 6362 psia, cement permeability at 0.003 md.



		Well 24
T_{wb}	K	552
T	K	584
T_{wh}	K	520
D_1	in	9.95
D_2	in	7.625
L_c	ft	3217
Initial L_f	ft	6433
Initial L_t	ft	0
μ_g	cp	0.015
P_{sc}	psia	14.7
c_m	psi^{-1}	1.5e-6
ρ_m	ppg	16
Z		0.92

Figure 5.7: Estimated pressure build-up compared to field data in “Well 24”.

Early SCP build-up is determined by mud compressibility, casing gas cap size and cement permeability. Later build-up is controlled by formation pressure and mud density. Because early and late pressure build-ups are affected by different parameters, realistic estimates of formation pressure, cement quality and expected casing pressures can be made even with assumed parameters by matching the theoretical pressure build-up pattern to field data.

6 Remediation

Once established, the remediation of SCP has proven inherently difficult due to the inability to access the affected annulus (Wojtanowicz et al., 2001). Remediation techniques can be divided into two main categories, rig and rig-less operations. The rig-less methods involve external treatments of the annulus by a combination of bleeding off pressure and injecting a sealing or killing fluid either at the wellhead or down in the well through a flexible hose. Rig methods involve moving in a drilling- or workover rig to perform remedial cementing operations. If other remediation techniques have failed, a last resort method may involve cutting and pulling the casing. Rig methods are generally more effective, especially for remediating issues related to the production casing due to accessibility.

During well construction, a drilling rig is present and can perform remedial cementing operations if defects are discovered during the construction phase. However, if SCP arises later in the life of a well, the costs associated with transporting and operating a rig are high. Rig-less methods are less expensive but have lower success rates. If a well is near the end of its life, involving a rig might be economically unfeasible (Wojtanowicz et al., 2001). Considerable amounts of data exist on remediation techniques and success rates due to the amount of leak remediations performed, but these data are generally not shared between operators, especially for failed operations (NRCan, 2019). This chapter presents conventional and new approaches to SCP remediation.

6.1 Rig-less Methods

Rig-less methods are typically preferred due to the costs related to involving a rig. These methods work in principle by injecting a high density fluid into the affected annulus and killing the SCP by pressure overbalance. Pressure in the annulus is reduced by bleeding off light weight gas and fluid, and the produced volume is replaced by a fluid of higher density, typically Zinc Bromide brine. This is repeated several times, and the goal is to gradually increase the hydrostatic pressure until pressure build-ups cease and SCP is killed. The process is often referred to as cyclic injection and can be divided into two categories, Bleed-and Lube and Casing Annulus Remediation System (CARS) operations.

The Bleed and Lube approach involves several cycles of injecting high density fluids directly into the casing head subsequent to bleed-offs. Field experience have shown that fluid amounts injected per cycle can be very small, and one operation reported pumping volumes as low as one quart (approximately one liter) per cycle. Required volumes of fluids necessary to provide adequate overbalance usually range from as low as

5 bbl to as high as 80 bbl, and such an operation would therefore have taken months or years to complete. Techniques involving pressurizing the casing to high levels in order to increase bleed-off volumes, and therefore injection volumes, to speed up the process can worsen the problem by microannulus formation in the cement sheath or formation break-down. The Bleed and Lube approach has proven successful in some wells but is not consistently effective. Field observations indicate that this method can in some cases increase the casing pressure. A hypothesis has been proposed that this is due to a new "gas bubble" migrating to surface (Wojtanowicz et al., 2001).

CARS operations work by the same principle, but instead of injection directly into the casing a small diameter, flexible hose is inserted through the casing valve and placed at a certain depth. Killing fluids are then circulated through this hose into the annulus. The CARS approach has proven successful in several wells, and the success rate might be higher than that of the Bleed and Lube approach. However, field experience has shown that the maximum injection depth cannot exceed 1000 ft. Most wells reported the injection depth could not exceed 300 ft. Injection depth is therefore a major limitation of this technique (Wojtanowicz et al., 2001).

Compatibility between mud already in the annulus and injection fluid should be considered in cyclic injection operations. Brine is not a good candidate for killing SCP in an annulus with a water-based mud, as these would mix in the annulus causing kill fluids to be produced together with mud and gas during bleed-off. Immiscible combinations of mud and kill fluids provide the most effective displacement of annulus fluids. Compatibility and kill fluid design are therefore critical for the efficiency of these operations (Wojtanowicz et al., 2001). Furthermore, if the source of the SCP is a permeable zone with non-negligible permeability a fluid loss agent should be placed below the kill fluid to prevent fluid loss to the formation (NOROG, 2008).

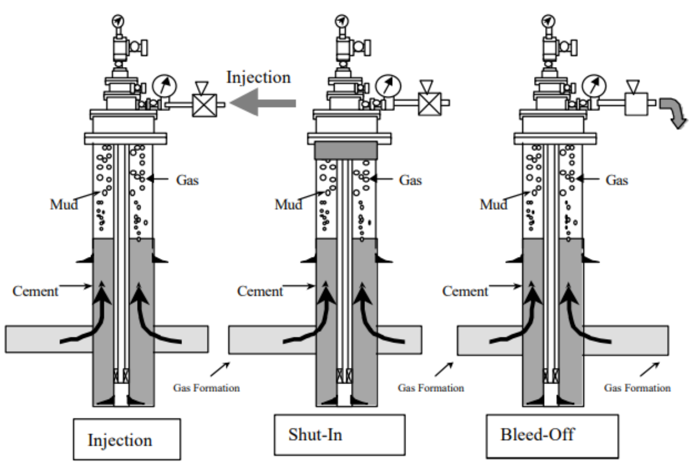


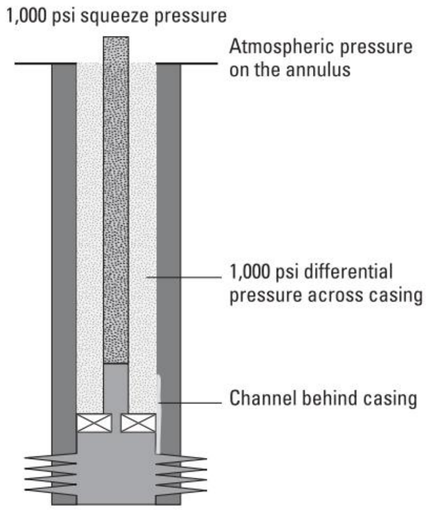
Figure 6.1: Cyclic injection procedure (Wojtanowicz et al., 2001).

6.2 Remedial Cementing

The term remedial cementing is used to describe the process of using cement to cure a variety of well problems. The process is generally divided into two categories; plug cementing and squeeze cementing. Plug cementing consists of placing an amount of cement and allowing it to set, while squeeze cementing consist of forcing cement into holes or perforations in the casing by pressure. Most cases of lack of zonal isolation causing SCP is remediated by squeeze cementing, while plug cementing is used for other types of operations (Nelson & Guillot, 2006).

Different techniques exist for squeeze cementing, but generally all follow a few common principles. The first step is wellbore preparation. If the slurry is to be injected some distance above the bottom hole, a drillable or retrievable plug, often high density fluid, is set below the squeeze area to prevent cement from flowing down into the well. A spacer fluid is then pumped to prevent cement slurry contamination and clean voids and perforations to be filled with cement. If squeeze cementing is performed late in the life of a well, tubulars in place can be covered in rust, debris, scales, or deposits that have accumulated over time. The spacer fluid helps to remove such materials. Squeeze cementing is typically performed with small volumes of cement, and contaminations can therefore significantly impact cement properties. A jetting device in combination with acids or surfactants can be used to wash tubulars and perforations prior to cementing. The washing tool is then removed. An injection test is performed, typically by injecting water, to ensure perforations are open and estimate cement injection rate, pressure, and volume. Before pumping the cement, a packer location is carefully selected to isolate the casing and wellhead while pressure is applied. If placed too close to perforations, the pressurized cement can create a channel behind the casing traveling above the packer location, causing the casing to collapse due to high differential pressures. If placed too high above perforations, the cement can channel through fluids in the hole to reach perforations, causing contamination.

The pre-determined squeeze pressure is then applied. If a high pressure squeeze technique is used, this pressure is above the formation break-down pressure and cement slurry is forced into the fractures. For low pressure squeezes, hesitation pumping starts as soon as the packer is set. This method consists of pumping a small amount of cement, waiting for pressure fall-off caused by cement filtrate entering formation and repeating as long as squeeze pressure continues to build. For both methods, pumping continues until no pressure leakoff occurs. A pressure test of 500 psi above final squeeze pressures typically indicates the end of the injection process.



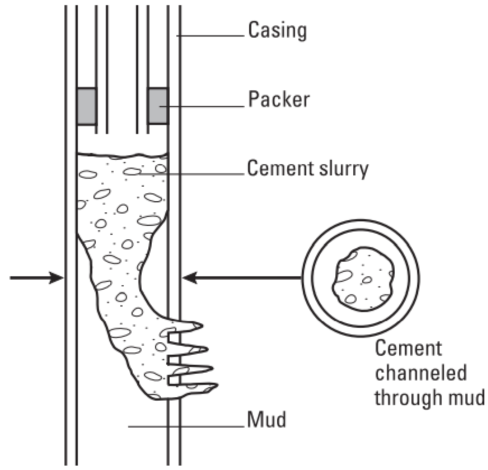


Figure 6.2: Casing collapse risk (Nelson & Guillot, 2006).

Figure 6.3: Cement slurry contamination risk (Nelson & Guillot, 2006).

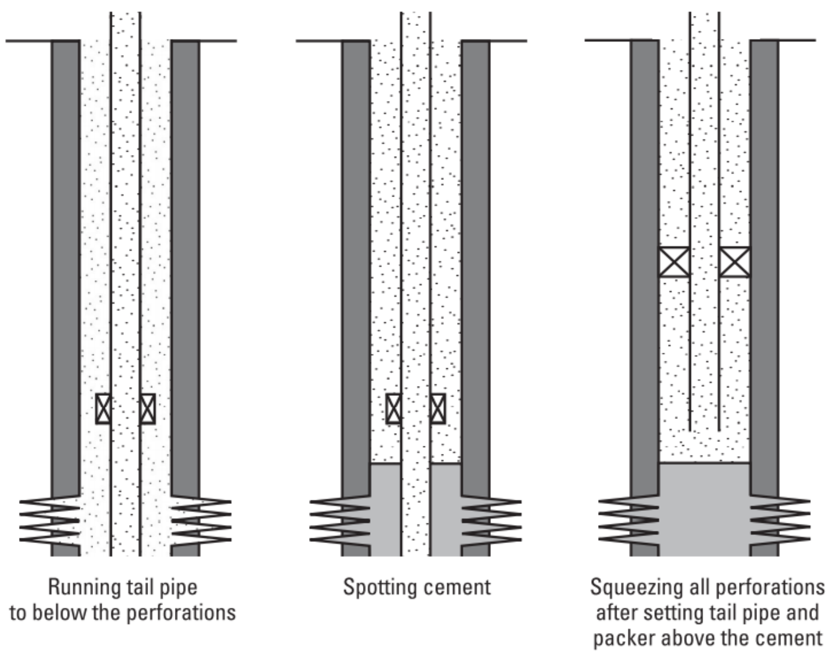


Figure 6.4: Squeeze job with a retrievable packer (Nelson & Guillot, 2006).

Figure 6.7: Typical pressure plot during squeeze treatment (Nelson & Guillot, 2006).

During most squeeze placements, the solid particles in the cement are too large to enter the formation matrix. An external cement filtercake therefore accumulates, filling perforations and forming “nodes” that protrude into the wellbore as the cement sets. The size of the nodes is determined by setting time, cement properties, squeeze pressures and wellbore temperatures. If the cement is allowed to fully set, these nodes develop until the entire wellbore is bridged and all cement has cured. The wellbore must then be drilled out. Removing the excess cement before fully setting therefore provides a clear benefit in terms of time and cost. However, this process can damage the cement nodes. The timing of such an operation is therefore critical.

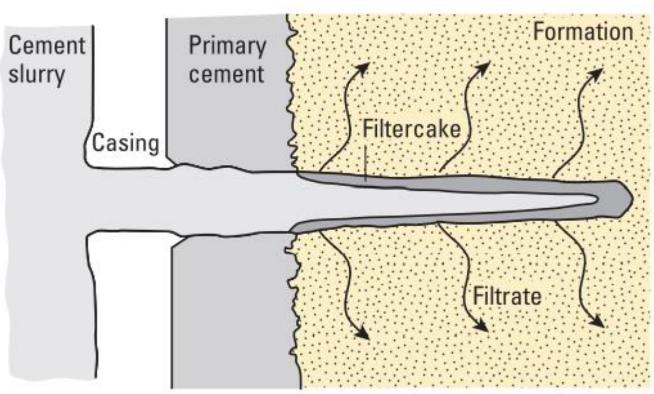


Figure 6.8: Filtercake build-up into a perforation channel (Nelson & Guillot, 2006).

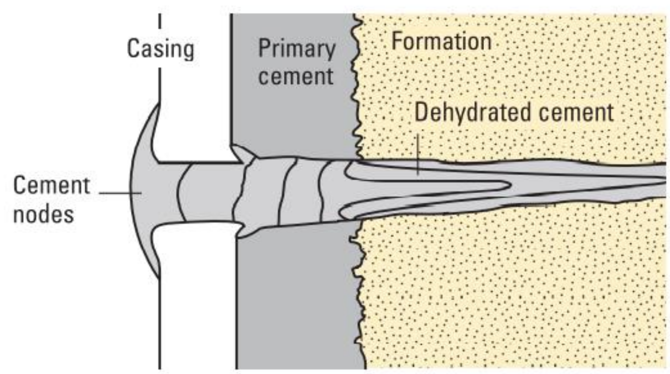


Figure 6.9: Cement channel properly filled with dehydrated cement (Nelson & Guillot, 2006).

Excess cement removal can be done by reverse circulating or contamination by injecting a contamination fluid, prohibiting cement setting, before direct or reverse circulation out of the hole. Finally, the squeeze job is evaluated. A preliminary check is done to make sure cement nodes allow for safe passage of measurement tools before the cement job can be evaluated like with a cement job evaluation like described in 4.1.5 (Nelson & Guillot, 2006).

Bradenhead squeeze

The Bradenhead squeeze is a popular low pressure squeeze placement technique due to its simplicity. The technique involves no special tools and is performed without a packer. Tubing is run down to the bottom of the cementing zone and cement is placed below the perforations, like described in Figure 6.10. After cement has been placed, the tubing is pulled up above the cement, BOPs are closed around the tube, and pressure is applied through the tubing. Excess cement can then be reverse circulated out of the hole after cement nodes have formed.

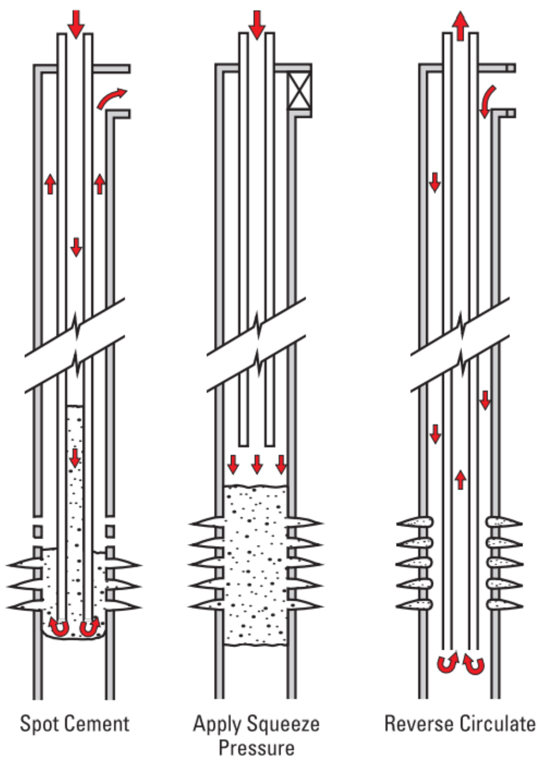


Figure 6.10: Bradenhead squeeze process (Nelson & Guillot, 2006).

Circulating squeeze

Circulating squeezes are typically performed to cement mud or gas channels. The casing is perforated at the top and bottom of the mud channel, and the channel is circulated with acid or water and a wash fluid. A drillable cement retainer is typically used instead of a packer, due to the high possibility of cement entering the casing through the top perforation. Retrieving the packer in such cases can be difficult, and the tube can become stuck in the hole. The retainer is set as close as possible to the top perforation to avoid casing exposure to cement that may enter the wellbore. No pressure build-up occurs during the job except for the hydrostatic pressure provided by the cement column in the annulus. Because void volumes are unknown, large volumes of slurry is prepared. One drawback to this method is the difficulty related to accurately perforating the casing around the channel. However, the low pressures means it can be performed in a casing with uncertain burst and collapse pressures, which may be the case for older wells due to degradation (Nelson & Guillot, 2006).

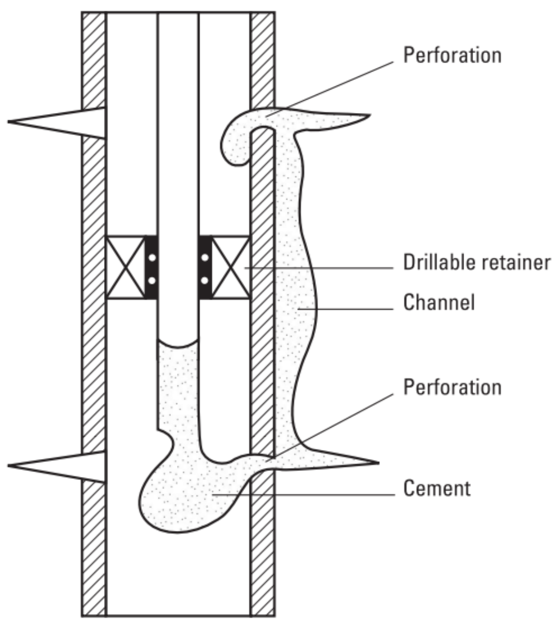


Figure 6.11: Circulating squeeze (Nelson & Guillot, 2006).

High pressure squeezes

Literature reviews show most authors recommend low-pressure squeezes whenever possible. However, low pressure squeezes can in some cases not be effective for SCP remediations. Perforations may not directly connect to cement channels behind casing and, like discussed in earlier chapters, microannuli between casing and cement can be only a few micrometers large. This is too small to allow the passage of cement slurry. In such cases, channels and leakage paths must be enlarged in order for cement to be placed, which is achieved by fracturing the formation at or close to the perforations. Fluids ahead of the cement slurry are displaced in the fractures, allowing the slurry to fill the desired spaces. Further pressure is applied to force the cement against formation and fracture walls while setting, ideally leaving all leakage paths filled with impermeable cement. However, during hydraulic fracturing, the location and orientation of fractures cannot be controlled. Fractures occur along the plane perpendicular to the direction of the formations least principal stress. Typical for sedimentary rocks are low tensile strengths, and they may be held together primarily by the compressive forces provided by formations above, leading to higher vertical stresses than horizontal stresses. High pressure squeezes will then produce vertical fractures (Nelson & Guillot, 2006).

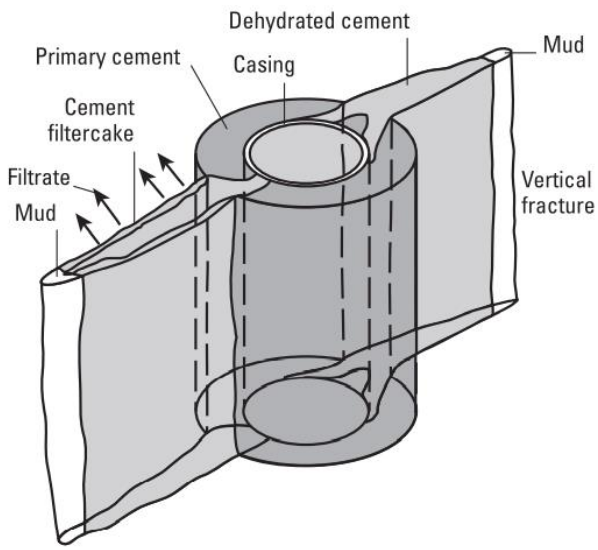


Figure 6.12: Vertical fractures due to high pressure squeeze – Vertical stresses in the formation are larger than horizontal stresses, fracture planes occur perpendicular to the direction of the least principal stress (Nelson & Guillot, 2006).

Squeeze cementing failures

If a cementing job fails, a thorough investigation into why failure occurred must be conducted to improve subsequent treatments. Common reasons why squeeze placements fail include improper final squeeze pressures. A high final squeeze pressure does not increase the chance of a successful job, but it does increase the chances of formation fracture and losing control of the cement slurry. Fractures created in the process can extend between zones, creating communication between zones that were previously isolated. Plugged perforations must also be considered. Incomplete or unsuccessful perforation washing can leave materials trapped in the perforations that allow for formation fluids entering the well. Mudcake can withstand high levels of pressure when applied towards the formation but cleans up easily when pressure is applied in the other direction. Debris, scale, sand, pipe dope, rust and paint can also accumulate and plug perforations. In a producing well, plugged perforations are often found in lower zones while upper perforations are open. Squeezing under such conditions will not fill all perforations, allowing for flow into the well. Perforating a casing to perform squeeze cementing can therefore create integrity issues in itself, if the cementing job is not successful (Nelson & Guillot, 2006). Squeeze cementing for microannulus remediation requires establishing complete circumferential coverage of the casing, which is difficult through access in the wellbore. The success rate for SCP remediation by squeeze cementing is therefore low (Wojtanowicz et al., 2001). A field study on 137 squeeze cementing operations for SCP remediation found a success rate of 34% for first-attempt jobs. Success rates for later attempts did not exceed 60%, despite as many as five squeeze cementing attempts having been made for some wells. The wells in the study were 30 to 50 years old and averaged 5000 ft in depth (Kupresan, Heathman & Radonjic, 2014).

6.3 New SCP Remediation Technology

6.3.1 Thermal activated resins

Thermal activated resins are particle-free, polymer resin based liquid sealants. Unique for resins are that they can be designed to have a specific viscosity, density, setting temperature, and setting time. Viscosities can range from 10 – 2000 cP, densities can range from 0.75 – 2.5 g/cm^3 and setting temperatures can range from 20 - 150˚C. Setting time can be designed as desired by adding curing inhibitors. Ductility and flexibility is typically higher than that of cement (Al-Ansari et al., 2015).

One case study of a well exhibing SCP in the production casing is presented. Pressures were frequently bled down from 600 psi to 150 psi, but could not be bled to zero. 210 liters of resin was prepared for injection at the wellhead. Curing temperature was designed at the ambient temperature, 40˚C, and curing time was designed at 1.5 hours. This particular casing was filled with water, and the resin was therefore designed with a density above that of water to allow for effective displacement. The resin was pumped at a rate of 6l/min until all water was displaced and resin was returned at the surface. The return port was shut, and an additional amount of resin was pumped to achieve a “squeeze”. 1000 psi pressure was applied to the annulus, and valves were closed. A resin sample was pumped at the surface for testing purposes. After 1.5 hours, the surface sample was fully set. Pressure was bled off from the annulus and potential returns was observed. A pressure test of 500 psi was applied for 10 minutes. No changes in pressure were observed.

The pressure was bled down to 0 psi differential pressure (atmospheric conditions) and pressure was monitored for 24 hours. No pressure changes were observed. SCP was concluded to be succesfully remediated (Al-Ansari et al., 2015).

6.3.2 Casing Expansion

Expandable casing technology is commonly used in extended-reach drilling to reduce drilling costs and preserve optimum casing diameter at reservoir depths. Two types of expandable casing systems exist. One uses a solid tubular to expand every joint of the liner, the other is used at the top and bottom of an interval. SCP remediation by casing expansion works in principle by increasing casing diameter and closing a microannulus. During the process, pipe length decreases, and wall thickness is reduced. As a result, collapse pressure decreases due to the change in diameter to wall thickness ratio. However, the reduction in wall thickness is small and values of 0.5% to 0.6% of the expansion ratio have been concluded (Kupresan, Heathman & Radonjic, 2014).

One experiment by Kupresan, Heathman & Radonjic (2014) investigated the potential for the technology as a remediation technique for SCP by closing the microannulus. The experiment consisted of a bench-scale physical model of a casing expander and three samples of 28 day cured cement sheaths between two casings. A microannulus was created by repeatedly rotating the inner casings during cement hydration. An expansion cone was pulled through the inner casing, expanding its diameter, and compacting the cement sheath. 2%, 4% and 8% expansion cones were tested. The samples were tested for flow before and after expansions.

Figure 6.13: Expansion fixture system. 1 – Hydraulic cylinder with piston rod, 2 – Upper housing, 3 – Integrated-load cell, 4 – Expansion-cone spot, 5 – Lower housing, 6 – Retaining mandrel (Kupresan, Heathman & Radonjic, 2014).

Prior to the expansion, effective permeabilities of the microannuli in the three samples was calculated at 0.14, 2.11, and 7.04 D. The sealing of the microannulus was apparent immediately after the expansion, and no flow was registered in any of the three samples when tested two months later. A change from a solid, hydrated structure into a softer material was observed in the cement after compaction. After having rehydrated for one week, cement consistency was physically of the same appearance as prior to the experiment, but a reduction in porous structure was observed on a microscopic level. Limited to a 2 ft. sample at ambient temperatures and pressure, casing expansion was proven to be successful for mitigating microannular gas migration at the tested conditions.

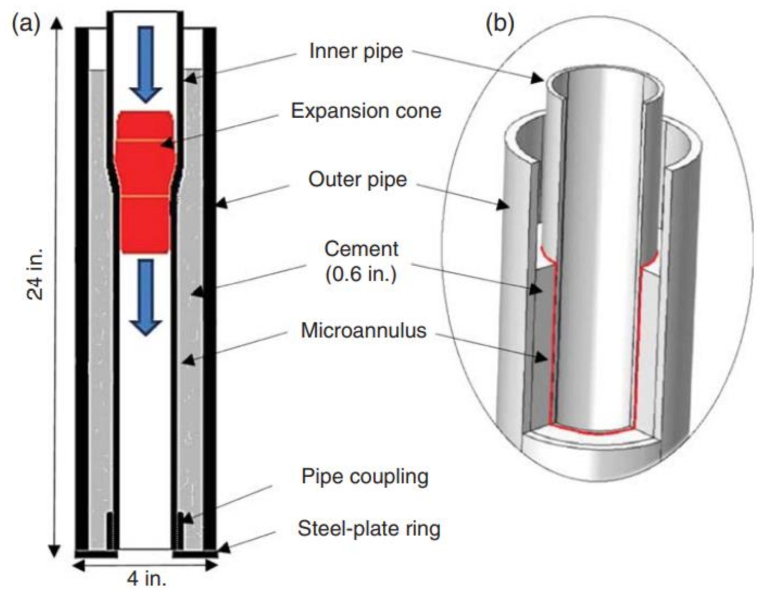


Figure 6.14: Schematic of composite sample (Kupresan, Heathman & Radonjic, 2014).

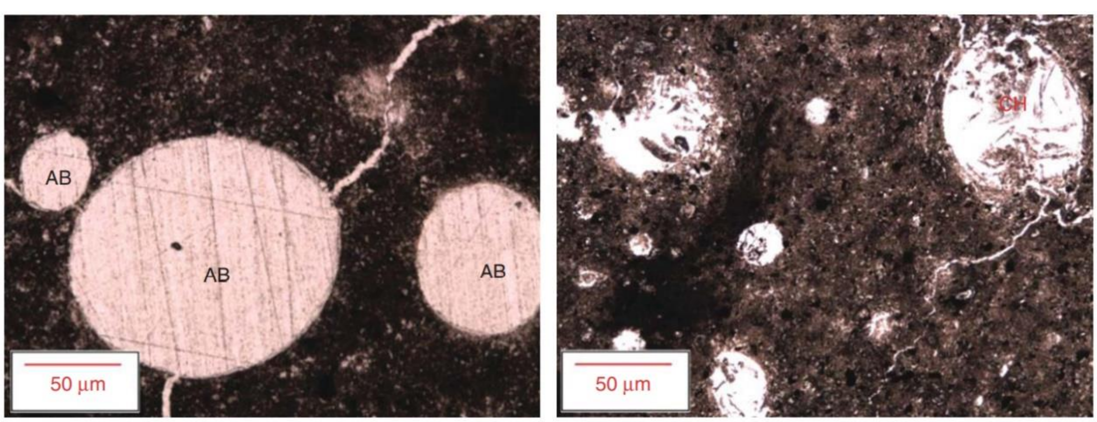


Figure 6.15: Microstructure before (left) and after (right) compaction. Air bubbles (in white) have deformed and mineral precipitation has occurred (Kupresan, Heathman & Radonjic, 2014).

7 Discussion

The review presented in this thesis show that annular flow issues occur in a significant number of wells. Available literature did not provide statistics for SCP occurrence on the NCS, but well integrity statistics are presented in the RNNP report using the well integrity categorization system. Based on the significant number of wells exhibiting SCP outside the NCS, significant number of mechanisms that can lead to SCP, and 31.0% of NCS wells reporting some degree of integrity impairment in 2020, it would be unreasonable to assume that SCP does not occur on the NCS. Making a conclusion as to the scope of the problem on the NCS is however difficult.

The review of NCS regulations, standards, and supplementary literature to these (Norwegian Oil and Gas Guideline no. 117) show that practices for avoiding well control situations and uncontrolled releases in wells exhibiting SCP are thoroughly described. Practices for avoiding the occurrence of SCP is however not defined.

It is found that a large number of mechanisms can lead to lack of zonal isolation and leakage paths in a well. Most of these mechanisms are attributed to failure of the cement. A microannulus is frequently formed between casing and cement sheath. This formation can occur through factors related to construction, cement design and hydration, downhole conditions, and daily operations. Operations that consist of lowering the pressure in a casing from a high value to a low value has a tendency of producing a microannulus, including operations such as fluid swaps and leak-off tests. Achieving a high level of security against the occurrence of SCP is therefore difficult.

The pressure build-up model presented by Xu & Wojtanowicz (2001) could provide useful in locating a source formation by estimating its pressure, or assessing cement quality by estimating its permeability. A limitation to this model is however that it considers the entire cement column to be of uniform properties. When applying this model, this limitation must be considered.

Review of available remediation techniques show that such operations have low or inconsistent success rates. No consistently effective remediation technique has been found. Squeeze cementing operations that include perforating the casing run the risk of worsening conditions if perforations are not successfully cemented. High pressure squeezes run the risks of producing communication between zones that were previously isolated due to fracture patterns being difficult to control.

A literature review was conducted on new developments in SCP remediation technology. The amount of quality analyses and case studies found on alternative technology applications to SCP problems was expected to be higher. The lack of literature found could be due to little research conducted in this field, but also due to an incomplete literature search. However, the two technologies presented herein, casing expanders and thermal activated resins, indicate that efforts are being made to produce alternatives to conventional workovers.

The experiment on a casing expander by Kupresan, D., Heathman, J. & Radonjic, M. (2014) proved successful in closing a microannulus in a bench sized sample. Changes were observed in cement microstructure and it is therefore not unlikely that mechanical properties have been altered. Potential changes will clearly need to be investigated. Microannulus formation is affected by cement properties and can occur due to temperature and pressure changes in the well during operation. It is not unrealistic to assume that the stress conditions that caused the initial microannulus may reoccur in the well. A particularly interesting topic is therefore whether the compacted cement can withstand these same conditions. A recommendation for future work is to produce a microannulus by a stress cycle, closing said microannulus by casing expansion and assessing how cement sheath permeability is affected by further stress cycles.

During the research process, several companies were found offering resin treatments. Literature presented by these companies was very positive to the viability of resins as a SCP remediation technique. However, this literature was not of a particularly critical nature and therefore intentionally left out of this thesis. Extensive research on durability and failure scenarios of resin treatments did not appear to be publicly available. It should however be mentioned that attempts were not made to obtain such literature directly from these companies.

The case study by Al-Ansari et al. (2015) presented on a resin treatment concluded that SCP was successfully remediated after no pressure increase was observed in the annulus for 24 hours. The author of this thesis is however critical to this conclusion due to pressure build-ups often occurring over longer periods of time. Common SCP cases will see pressures quickly increase subsequent to a bleed-off, before stabilizing at a certain level. The absence of a pressure increase could indicate successful remediation, but a longer assessment of pressure trends would inspire more confidence in the success of this resin treatment case. A recommendation for future work is to assess pressure trends for longer periods of time subsequent to a SCP resin treatment and compare these to pressure trends prior to the treatment.

If proven to be viable, resin treatments could provide advances in rig-less approaches by injection through casing valves, without the need to bring in a workover rig. This could potentially reduce remediation costs by significant amounts. The ability to design a resin at a particular viscosity could also be useful in closing a microannulus. It is found that cementing treatments often prove unsuccessful for this due to the difficulty of achieving good coverage around a casing by squeeze cementing. One reason for this is cement particle size. A low viscosity resin could potentially flow more effectively into the small space of the microannulus and create a seal.

8 Conclusion

With what has been presented herein, the following conclusions can be made:

- Leakage paths resulting in SCP can be caused by a large number of mechanisms.
- Achieving a high level of security against the occurrence of SCP is very difficult, if not impossible.
- Conventional technology for SCP remediation does not prove consistently effective.
- No technology exist today that has been proven consistently effective in SCP remediation.
- Efforts are being made to develop alternative technologies for effective SCP remediation.

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