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Well Barrier Restoration Across Dual Cemented Liners

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Abstract

In the past years there has been an increased focus on decommissioning of wells in the NCS. Decommissioning of wells introduces significant investments with no financial returns and has for those reasons historically had less focus. The expected large cost of Plug and Abandonment (P&A) is a massive expense for the license holders, the State, and Norwegian tax payers who contribute with 78% of the total sum of P&A [1]. A reduction of these costs could therefore be considered an advantage for all contributors. Optimizing already existing technology and introducing new methods of performing P&A operations, such as rigless P&A, may therefore contribute in making P&A more economically sustainable.

Cement Bond Log (CBL) is the commonly used tool for verifying external barriers downhole in a well. This has proven to be challenging because two casing strings must be set to obtain an acceptable barrier for production as per requirements. Today's CBL tools are not capable of logging through two casing strings. To get an adequate signal response from the CBL, one would have to mill or cut and pull the inner casing, and pull the tubing, which is normally done using a rig. The industry is lacking the technology to verify barriers for P&A purposes through two casing strings, owing to insufficient logging tool capability. There is a demand for a method to establish well barriers without logging, preferably rigless which would save cost.

The main purpose of this thesis is to document and share the knowledge and experiences obtained from a suggested approach of barrier restoration first performed by Aker BP in 2017. The idea was to perforate zones and perform pressure tests through perforations, to establish communication to the formation outside the outer casing, and thereby verify barriers downhole for P&A purposes. The operation was performed rigless by using Coiled Tubing (CT). The thesis will view whether this technology could be an alternative to the CBL and still be feasible and fulfil the requirements defined in NORSOK D-010.

Results from the case study form an adequate basis to consider eliminating the conventional CBL tool where two casing strings exist. The evaluated method is sufficient to identify hydraulic sealing intervals, and by using the proposed method, the barrier requirements given in NORSOK D-010 were achieved. The method introduced economic benefits because there was no need to cut and pull the inner casing in order to log the cement outside the outer casing. Aker BP also estimated that the use of CT was six times cheaper than using a rig [2]. Finally, both the Christmas Tree (XMT) and CT Blow Out Preventer (BOP) were rigged up all the time resulting in a very safe operation, hence reducing HSE risks [3].

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Abbreviations

BHA - Bottom Hole Assembly

BOP - Blow Out Preventer

CBL - Cement Bond Log

CT - Coiled Tubing

DPZ - Distinct Permeable Zone

ECP - Equivalent Circulating Density

FBP - Formation Breakdown Pressure

FCP - Formation Closure Pressure

FIT - Formation Integrity Test

FPP - Formation Propagation Pressure

FRP - Fracture Reopening Pressure

HSE - Health, Safety and Environment

IJSP - Inflatable Jet Set Packer

IRPP - Inflatable Retrievable Production Packer

ISIP - Instantaneous Shut-In Pressure

LOP - Leak-Off Pressure

LOT - Leak-Off Test

LWIV - Light Well Intervention Vessel

MD - Measured Depth

NCS - Norwegian Continental Shelf

NUI - Normally Unmanned Installation

P&A - Plug & Abandonment

PAF - Plug and Abandonment Forum

PDO - Plan for Development and Operation

PIT- Pressure Integrity Test

POOH - Pull Out of Hole

PP&A - Permanent Plug & Abandonment

PPFG - Pore Pressure Fracture Gradient

PSA - Petroleum Safety Authority

RIH - Run in Hole

TCP - Tubing Conveyed Perforating

TVD - Total Vertical Depth

UISI - Underbalance Induced Shale Influx

UWHP - Unmanned Wellhead Platform

WBE - Well Barrier Element

WBS - Well Barrier Schematic

WI - Well Intervention

WL - Wireline

XLOT - Extended Leak-Off Test

XMT - Christmas Tree

Symbols

D/t - Diameter/thickness

Ft. - Foot (measuring unit)

In. - Inches

Ppf - Pounds Per Foot

S_H - Horizontal Stress

S_{Hmax} - Maximum Horizontal Stress

S_{Hmin} - Minimum Horizontal Stress

S_V - Vertical Stress

μD - Micro darcy

1. Introduction

1.1 Motivation for Study

Permanently plugging and abandoning wells do not provide any future cash flow for the involved companies; thus, it should be investigated if any cost-efficient technology can be applied to reduce the time and funds spent on P&A. In a presentation at the Norwegian Plug and Abandonment Forum (PAF), Martin Straume estimated a total cost of 876 billion NOK for future P&A activities on the Norwegian Continental Shelf (NCS), in which 78% of that sum is paid by Norwegian tax payers [1]. A large part of this sum comes from the daily rig rate. An alternative that has been studied the past years is performing parts of the P&A procedure rigless. This would release rigs to perform activities that create a positive cash flow, such as drilling and production. Rigless P&A furthermore removes the additional expense of daily rig rates, potentially creating a massive saving which would be of interest for both the companies, State and tax payers.

Figure 1.1 illustrates the lack of technology related to logging through two casing strings, which has introduced challenges in the process of establishing external barriers for P&A purposes. Identifying adequate external barriers outside casing strings are required to install internal cement plugs for P&A purposes. With no logging tools able to log through more than two casing strings, the standard procedure is to mobilize a rig on site. Further, the tubing is pulled and the inner casing is cut and pulled. Alternatively, section milling can be used. A CBL is then run into hole attempting to log to verify cement or formation barrier outside the outer casing string.

This has also challenged wells on Valhall DP that are completed with dual cemented liners. Attempting to overcome the challenge of identifying sufficient external barriers, as well as avoid using a rig, Aker BP employees searched for other methods to verify and qualify the cement bond outside the casing strings. In the early months of 2017, Aker BP tested an approach for barrier restoration across dual cemented liners on the first of several wells. This was an attempt to restore the cap rock seal. The operational sequence of the rigless proposed method included running into a well with a CT to perforate the well in several zones with a suggested 30 meter interval between the zones. Perforations are typically done when preparing a well for production to enhance the flow communication between the reservoir and the wellbore [4].

This principle was used, and Extended Leak-off Tests (XLOT) and communication tests in the perforations were performed to debunk communication in both the annulus between the zones and down to the reservoir.

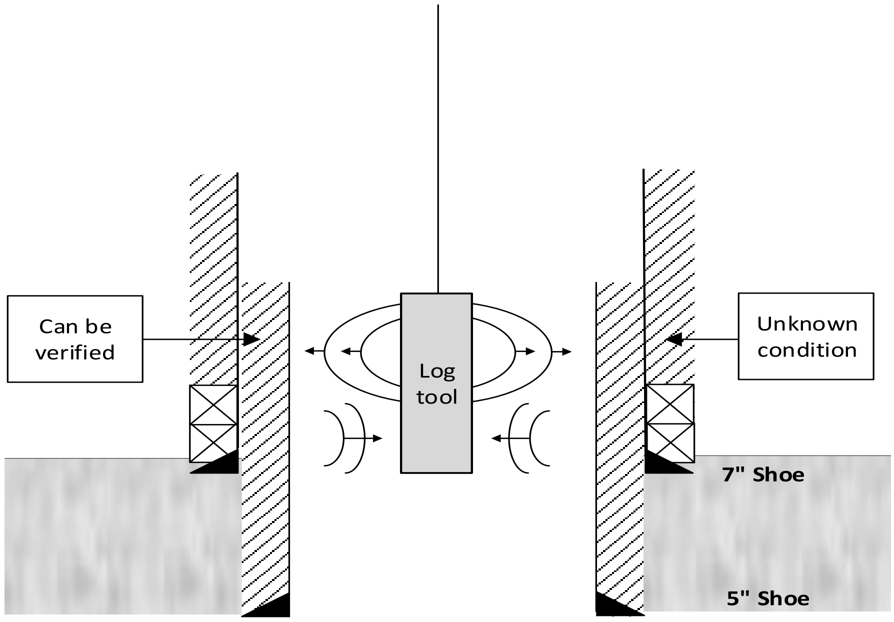


Figure 1.1 Logging tool unable to log through two casing strings

The team quickly established a track of record and could apply the simplified procedures on analogous wells. Based on learnings from repeated operations and trying different tools, the team was able to improve their efficiency by simplifying the operations and optimizing the tool selection. In addition to obtaining satisfying results, the operations introduced important Health, Safety and Environment (HSE) related benefits and savings regarding cost by avoiding the use of a rig and logging tools [5].

Aker BP has for many years shared lessons learned and experiences within P&A with the industry through PAF. The main motivation of this thesis is to document and share the knowledge and experiences obtained from implementing the suggested approach of barrier restoration. The case study will evaluate both successful and failed tests. It will further investigate whether this innovative method could be an alternative to the already existing P&A technology and still be feasible and fulfil the requirements of NORSOK D-010.

1.2 Structure of Thesis

The thesis is divided into ten chapters with following subchapters. For the reader to fully comprehend the extent of the proposed approach, relevant theoretical support, both common knowledge and internal will be provided throughout the thesis. It is considered necessary to define the concept of P&A along with its main purposes and challenges, furthermore presenting CT elements and its application areas and finally, regulations for the NCS.

The main chapters may be summarized to:

- **Chapter 1:** Introduces P&A within the NCS, and a motivation and structure of the thesis.
- **Chapter 2:** Introduces the term of P&A including the faced challenges, the conventional operational sequence and the concept of rigless P&A.
- **Chapter 3:** Describes the regulations and standards for the NCS and introduces NORSOK D-010 and its requirements regarding P&A.
- **Chapter 4:** Presents the technology and equipment used for P&A on the three wells considered in this thesis, as well as their original area of application. This chapter also includes advantages and disadvantages of using CT vs. rig.
- **Chapter 5:** Gives a presentation about the Valhall field and the geological challenges that has led to the need of plugging and abandoning the wells located on the field.
- **Chapter 6:** Gives a thorough presentation of the tests used in the proposed method. Because these tests are a major part of the proposed approach, this chapter carefully explains and illustrates these and provides examples of various scenarios. This section describes the tests as performed by Aker BP in the proposed approach. It may therefore not be considered as standard industry tests, either in well configuration during the tests or the test procedures themselves.
- **Chapter 7:** Presents the proposed approach for barrier restoration.
- **Chapter 8:** Presents a case study of the three wells that was plugged and abandoned using the proposed approach. Each case includes data, the operational sequence, results and an interpretation and discussion.
- **Chapter 9:** Presents a justification of the proposed approach by discussing various aspects of the approach.
- **Chapter 10:** Conclusion and suggested future work.

2. Plug and Abandonment

As of April 2018, a total of 6255 wells could be found on the NCS. This is a combination of exploration wells, development wells and already permanently plugged and abandoned wells [6]. Common for all these wells, is that they must be plugged and abandoned at one point in the years to come when they reach the end of their lifetime.

When a well reaches the end of its lifetime, it must be decommissioned. Decommissioning could be defined as all activities performed to shut down and discard something from service or remove from active status. In this case, facilities and equipment used in the wells are considered [7]. Decommissioning of a well may also be referred to as P&A, which will be the term used in this thesis. Driven highly by economics, P&A will be performed as soon as a well experiences negative cash flow, which means that the operating expenses are higher than the operating income. Other reasons that dictate the end of a wells lifetime are mentioned below, but not limited to:

- Integrity issues
- Depleted reservoir
- Water/gas coning

Because P&A has no value creation, it is of great importance that P&A operations are performed as effective as possible to limit expenses. The operations are complex and need detailed planning, accurate time and cost estimations and a large focus on risk and safety. Some of the focus areas of P&A are HSE, that the operations comply with regulations, reliable for eternity and cost effectiveness [8]. The following subchapter will define P&A, the challenges that may occur, give a description of the conventional method of performing P&A and introduce the term of rigless P&A.

2.1 Definitions

P&A is the process of plugging and sealing off a well with the purpose to abandon it, either for a short period of time or with an eternal perspective. A well is plugged by setting barriers downhole with intention to ensure permanent well integrity. This will also avoid damage on the external environment. The key issue within P&A is to ensure no upwards migration of hydrocarbons, hence the barriers downhole need to prevent both vertical and horizontal migration. It is difficult to predict where a leak can end up when hydrocarbons migrate to different zones or to surrounding formations. This uncertainty is dangerous because there is a potential risk of a leak to the surface threatening the environment, or a leak into drinking water possibly harming human beings and animals.

With time perspective in mind, P&A can be separated into three major abandonment types, namely suspension, temporary abandonment and permanent abandonment.

Suspension - A well could be put into suspension status if there is a need for intervention work. Other reasons could be waiting on weather or equipment, or if the rig is skidded to do work on another well. While a well is in suspension status, the well control equipment is not removed [7].

Temporary Abandonment - As opposed to suspension, temporary abandonment involves removal of the well control equipment. A well is abandoned with purpose of later re-entry or future permanent abandonment [7]. There are no requirements on how long wells can be temporary abandoned, as long as they are continuously monitored. With no monitoring, the wells must be re-entered or permanently abandoned within three years. [9]

Permanent abandonment - According to NORSOK D-010, permanent abandonment involves permanent P&A of a well with no intention of later re-entry or further use [9]. The steps required to permanently abandon a well properly are given in regulatory standards and will be further elaborated in the following subchapter.

2.2 Abandonment Phases

NORSOK D-010 does not divide P&A operations into phases. A phase could in this context be considered as a set of minor operations that together completes one sequence of the entire P&A procedure. P&A can, according to "Guidelines on Well Abandonment Cost Estimation, Issue 2", be divided into three phases; Phase 1: Reservoir abandonment, Phase 2: Intermediate abandonment, and Phase 3: Wellhead and conductor removal [10]. These major phases are performed during a Permanent Plug and Abandonment (PP&A) operation regardless of the well type, location or status. In SPE-169203 [11], Moeinikia et al. suggests dividing P&A into phases as this could be useful because the various phases can be performed simultaneously during a P&A campaign. This means a certain phase is performed on several wells once a rig is mobilized to the field, reducing number of rig relocations. The complexity of the operations also varies, meaning distinct vessels might have to be used for the different phases.

In the same paper, Moeinikia et al. suggests implementing a fourth phase to the abandonment phases that includes preparatory work performed on a well before executing the other three phases. The preparatory phase, hereafter be referred to as Phase 0, could be performed using e.g. a Light Well Intervention Vessel (LWIV) [11]. The LWIV can be used for preparatory work on a well regardless of the complexity of the following three phases. This thesis will not be focusing on the guidelines provided by Oil & Gas UK, however, because NORSOK D-010 does not differentiate between the phases, some details from Oil & Gas UK guidelines will be used for informational purposes in this chapter.

2.2.1 Phase 0: Preparatory Work

The preparatory phase includes work such as killing the well, punching the tubing, circulation of heavy fluids and installation of temporary plugs to ensure well integrity. Because e.g. a LWIV can perform these operations, this phase can be performed rigless and there is no need to move in a rig, potentially saving both time and cost [11].

Phase 0 also includes running logging tools downhole to verify wellbore access such as checking for deformations and restrictions downhole. Ensuring sufficient wellbore access is crucial in order to run various tools downhole for further operations. If the tools are not able to pass downhole restrictions, misruns are made in which unwanted time and money are spent. Logging data may also be used for finding minimum setting depths. This depth is also referred to as the critical P&A depth within Aker BP, and is understood as the shallowest depth where the surrounding formation is capable of withstanding the maximum anticipated pressure without being fractured, for eternal perspective [5].

Other information that is useful to obtain during the preparatory phase, is an estimation of the formation fracture and pore pressures and further creating a Pore Pressure Fracture Gradient (PPFG) plot. A narrow window between these two pressures may pose a challenge for P&A operations because it may introduce restrictions regarding downhole fluid selection, removal of swarf and debris from milling operations in addition to downhole barrier placement. As later described, the well barriers set during P&A must be capable of withstanding all possible loads and pressures they may be exposed to with an eternal perspective, and obtaining a PPFG is therefore useful during preparatory work [9] [7].

2.2.2 Phase 1: Reservoir Abandonment

As the title indicates, the first phase revolves around abandoning the reservoir. It is desired to restore cap rock properties and ensure well integrity of the well with an eternal perspective. Phase 1 includes setting primary and secondary barriers to isolate the reservoir from the rest of the wellbore, and thereby restore the cap rock to its original condition before it was drilled into. This includes all producing or injecting zones. During this phase, the tubing may be either left in place, partly or fully retrieved [10]. Barrier restoration of the cap rock will be the main topic of this thesis, and reservoir abandonment will therefore be a more important phase compared to the other phases.

2.2.3 Phase 2: Intermediate Abandonment

Phase 2 includes isolating liners, milling and further retrieving casing strings and finally setting barriers. The barriers should isolate intermediate hydrocarbon- or water-bearing permeable zones. A surface plug is also installed to avoid shallow inflows. If the tubing was not retrieved during the first phase, this should be done during Phase 2 [10].

2.2.4 Phase 3: Wellhead and Conductor Removal

To finalize the abandonment process, the last phase includes cutting the wellhead, conductor casing and other shallow cut casing strings below the surface and then further retrieval. Phase 3 is conducted to avoid any incidents in the future involving marine activities such as fishing from trawlers [7].

2.3 Abandonment Operations Complexity

"Guidelines on Well Abandonment Cost Estimations, Issue 2" separates the complexity of abandonment work for each of the phases mentioned into five types, indicating what kind of vessel is required to perform a given phase in different wells [10]. An example of how complexity can differ between wells is verification of good cement behind several casing strings, which is one of the main topics of focus in this thesis.

There is a significant difference in the complexity between verifying a good cement bond by simply running a logging tool, compared to cutting and pulling a casing string. A logging operation could be done using a LWIV by running e.g. a Wireline (WL) with a logging tool, while a rig has to be moved onto site if cutting and pulling is required. These two vessels operate at different day rates, so being able to operate rigless with e.g. a LWIV could introduce a tremendous saving in cost. Inspired by "Guidelines on Well Abandonment Cost Estimations, Issue 2", the following table is presented to give an overview of complexity of the operations on a fixed installation and what nature of work is necessary for each type [10].

Well Abandonment Complexity	**Work Type**	**Work Description**
Type 0	No work required	A particular phase or phases of abandonment is already performed
Type 1	Simple, Rig-less work	WL, pumping, crane, jacks
Type 2	Complex, Rig-less work	CT, WL, pumping, crane, jacks
Type 3	Simple, Rig-based work	Involves retrieval of tubing and casing
Type 4	Complex, Rig-based work	Involves retrieval of tubing and casing, milling and cement repair operations. May have poor well data, access or poor cement.

Table 2.1 Well Abandonment Complexity, modified after [10]

To enable all P&A operations to be conducted rigless, appropriate methods and solutions to avoid type 3 and 4 operations must be found because these types require a rig. Coding wells after what work type is required makes it easier to identify wells with identical code, which will require the same work done. Once the wells are identified, a campaign may be initiated where the same operations can be performed on all similar coded wells, saving both time and money.

2.4 General P&A Challenges

P&A operations are challenging and known to be time consuming and costly. Previous experience show that older wells are more challenging to plug and abandon owing to lack of well data, poor cement quality behind the casing and difficulties accessing the wellbore from years of shifting of the layers of the Earth. This chapter introduces challenges that may be encountered during P&A.

2.4.1 Health, Safety and Environment

Offshore personnel are highly exposed to toxic gases and other hazardous substances such as drilling fluids and cement during P&A operations. The safety of the personnel is also at risk because of dangers on the platform deck related to crushing, falling objects, harsh weather and unexpected events, which in severe cases may be fatal. There are also environmental risks involved during P&A, e.g. accidental emissions and transportation of hazardous fluids and debris to shore. Solutions to reduce such HSE risks were investigated during the execution of the proposed approach. Some of the discovered HSE benefits are presented in Chapter 9.

2.4.2 Time and Cost

Nowadays, with available technology, it takes approximately 20-60 days to plug a well. The average estimation of a P&A job is 35-40 days per well [1]. Nevertheless, Aker BP has managed to plug an abandon a well in less than 20 days proving that exceptions to the average exist. This is illustrated in Figure 9.1. Using the conventional method to plug and abandon a well from a fixed installation, one rig can plug and abandon ten wells per year. According to a presentation given by M. Khalifeh in 2017, there are no available accurate statistics on abandoned wells on the NCS [8]. In OMAE2015-41261, Fjelde et al., suggest that as many as 3000 wells on the NCS must be plugged and abandoned in the years to come [12].

Nevertheless, combining that there are 6255 wells on the NCS as of April 2018 [6], with how many days P&A on average will take, it is fair to anticipate that the rigs will be occupied for many years to come.

In a presentation at the Norwegian PAF, Martin Straume estimated a total cost of 876 billion NOK for future P&A activities on the NCS, in which 78% of the sum will be covered by tax payers in Norway. A large portion of this cost comes from the daily rig rates. Improving or utilizing already existing technology for other purposes could allow for P&A to be performed rigless, potentially reducing the P&A cost tremendously [1].

2.4.3 Access to Wellbore

Subsidence of the seabed and formation resulting from reservoir depletion could cause challenges related to barrier establishment for P&A. Severe subsidence can lead to casing or tubing collapse. Subsequently, this could cause inaccessible wellbores and insufficient setting depths for permanent barriers because the setting depth may be below the collapsed casing. Deformed wells are another challenge in which uncertainties of the wellbore status below the deformation is introduced. This is a particular challenge for the Valhall field because the field has experienced severe subsidence since production started and up to date [12].

2.4.4 Cement Logging

Verification of cement bond in the annulus between casing and formation has conventionally been performed by running logging tools on e.g. a WL into a well. This is performed before well tests, before production is initiated or when well integrity is to be evaluated. Cement quality could be verified by running a CBL. The CBL records the transit time and amplitude of a sonic signal travelling from a transmitter to a receiver on the logging tool. It also evaluates both the hydraulic and mechanical seal of the cement bond, as well as cement conditions like channelling, compromised cement, top of cement or micro annuli. CBL is well-known, time efficient and is considered to be inexpensive compared to e.g. a communication test [13]. Nevertheless, there are several factors affecting the reliability of such logs, and considerations should be taken before initiating further operations based on the logging results.

One factor that challenge the conventional CBL, is wells completed with dual cemented casing strings. All three wells considered in this thesis are completed with dual cemented liners extending into the reservoir. This is illustrated in Figure 2.1.

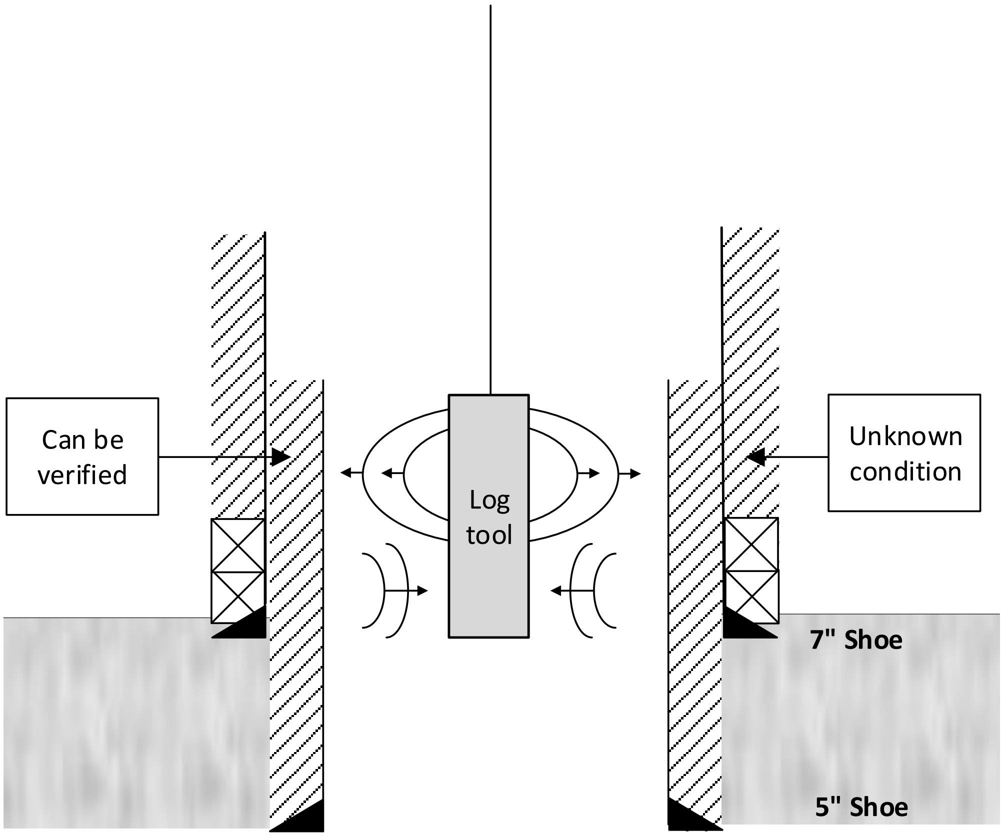


Figure 2.1 Dual cemented liners is a challenge for the CBL

Today, no technology is able to log through more than two casing strings. This introduces a challenge for the wells because it is crucial to obtain information regarding all cemented areas, especially the casing-to-formation cement bond outside the outer casing string. The common procedure today is to pull the tubing and cut and pull the inner casing to access the outer casing and log the external cement outside. This operation is complex and expensive because either a rig with derrick or a jack-up must be used to pull the heavy pipes. Solutions to overcome the challenge of logging through two or more casing strings are being examined, and both existing and new technology are being improved and developed. A solution to this challenge given by Aker BP is presented in Chapter 7. The presented solution avoids the need of cutting and pulling pipes. It is therefore not needed to mobilize a rig to the field, saving both time and funds.

2.4.5 Multiple Reservoirs and Abnormally Pressured Formations in the Overburden

To ensure sufficient sealing of a well during PP&A, it is according to NORSOK D-010 necessary to install a minimum of two well barriers if there are either hydrocarbon bearing formations present, or formations of abnormal pressure with potential to flow to the surface. Abnormal pressure is defined as a situation where the pore pressure is exceeding the normal, regional hydrostatic pressure [9]. This is a challenge during PP&A because the required operations are complicated. Depending on how many of these formations are present in the overburden, multiple casing strings may need to be cut and removed, and two additional barriers must be set for each of these formations [12].

2.4.6 Removal of Control Lines and Cables

Because of their potential of forming a leak path for fluids, control lines and cables shall be removed before permanent barriers are set downhole [9]. Wells with intelligent completion are facing a challenge regarding removal of these during P&A because they are attached to the tubing. As a result, the entire tubing with attached control lines and cables must be retrieved from the well.

Limited lifting capacity of e.g. CT, often results in the need of a rig for heavy operations, making removal of control lines and cables an expensive and complex part of P&A. Intelligent completions were implanted because it opened up for the possibility of remotely monitoring and controlling the wells. Conventional completions, which the three wells in this thesis is completed with, are normally retrieved with no further problems or difficulties [14].

2.4.7 Section Milling

As will be presented in Chapter 3, a permanent barrier must according to regulations, seal both horizontally and vertically as well as inside the wellbore and in the annulus. This is to ensure zero leakage occurring through or around the barrier, as illustrated in Figure 3.4 a) External barrier b) Internal barrier. Typically, a cement plug will be set as the internal barrier. The plug shall be set deep enough to prevent the maximum anticipated pressure below the plug from exceeding the fracture pressure in the well for eternal time perspective [7].

Consequently, the plug may be set in a section containing poor or no cement, resulting in a barrier that is not providing sufficient sealing. A remedial solution to establish a cross-sectional barrier in uncemented casing, is removal of the uncemented casing sections by milling. The process of section milling is typically executed in the following manner [15]:

- Milling of the uncemented casing section
- Cleaning the milled section by removing swarf and debris
- Underreaming the section (widening the milled section) to expose the formation behind
- Setting a cement plug by balanced plug method

Although section milling is useful when establishing permanent barriers, it is time consuming, costly and introduces HSE risks. It is primarily a HSE risk owing to surface handling and disposal of the created swarf. Swarf is metal cuttings from the casing string created during the milling process. These cuttings are sharp and can potentially damage surface equipment, the environment and personnel involved in the operation.

To effectively transport the swarf and debris to surface, a fluid designed with special properties is used to ensure sufficient viscosity and weight to transport the cuttings and maintain a stable wellbore. The viscosity of the milling fluid may become challenging for the milling process, because the corresponding Equivalent Circulating Density (ECD), which is an increase in density caused by friction, may exceed the fracture pressure and lead to loss of fluids. Large losses can lead to packing off of the Bottom Hole Assembly (BHA) [15].

As previously mentioned, there is no technology available for logging through several casing strings, and in that case, section milling may need to be initiated. Being already expensive, time-consuming and challenging when performed on one casing, section milling will introduce even higher cost and more challenges when a heavy wall liner is installed inside another liner with cement in between. This is the case for wells on Valhall DP and highlights the importance of finding other methods for verification of external cement barriers.

2.5 Operational Sequence - P&A from a Fixed Installation

P&A operations from rigs are complex and time consuming, and is an inevitable cost that provides no positive cash flow in return for the companies. The four phases of the abandonment procedure mentioned in Chapter 2.2 could be used as a general frame of what is to be achieved from the various operations. Nevertheless, the regulatory framework on the NCS does not describe *how* an operation should be executed, rather *what* is the desired result. Subsequently, there is no specific operational sequence for P&A because companies might have different perceptions and approaches to the various P&A operations, and not to mention how wells could vary in degree of complexity.

Because the three wells in the case study are completed with dual cemented liners, the following operational sequence is presented as an example of a possible P&A scenario with similar well configuration. The aim is to provide material to compare with the proposed approach in Chapter 7 [12]:

1. Rig is mobilized to the location.
2. The well is killed by bullheading heavy fluid downhole.
3. XMT is nippled down and BOP nippled up.
4. Removal of tubing either because of attached control lines or desire to log behind 7 in. or 9 5/8 in. casing.
5. Mill out/cut and pull inner liner (5,5 in., 45,5 ppf heavy wall).
6. Run CBL to establish annular cement. If poor quality, perf, wash and cement or section milling may be implemented.
7. Establish primary and secondary barriers.
8. Install environmental plug.
9. Initiate Phase 3 of the abandonment: wellhead and conductor removal.
10. Demobilize rig.

After P&A, the well shall have primary and secondary barriers to seal off against each reservoir and permeable zone, and an environmental barrier. The environmental barrier may also be referred to as a surface plug because it is set close to the surface in order to isolate the well from external activities such as fishing. Figure 2.2 shows an example of the various barriers set during PP&A. Blue represents primary barrier, red are the secondary barriers and green illustrates the environmental barrier.

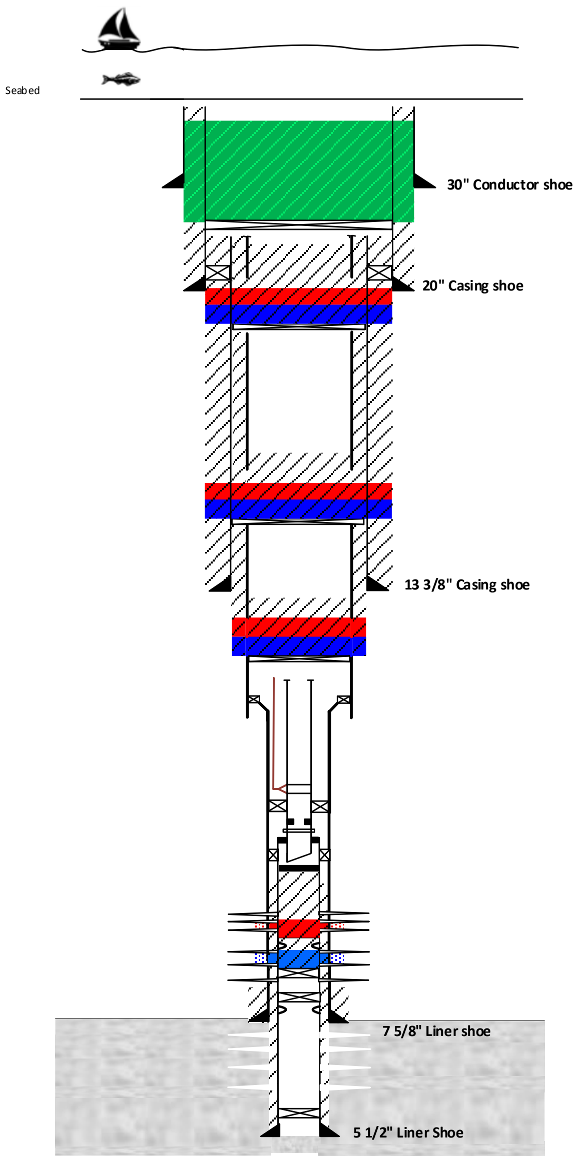


Figure 2.2 Example of barriers after PP&A

2.6 Rigless P&A

Rigless P&A has been discovered to be noticeably cost efficient because it involves only a minimum of equipment and less personnel compared to rig based operations. The goal of rigless P&A is to release the rigs to maintain drilling and completion activities which are the core functions of rigs, as well as it creates a positive cash flow [12].

Floating vessels such as a LWIV can be used to perform rigless P&A on subsea wells, whereas rigless P&A on fixed installations could entail e.g. WL or CT. Valhall DP is a fixed installation without a derrick, therefore the proposed approach was performed rigless using CT from the platform, while a jack-up standing above the platform was performing work on other wells. CT was initially designed for use in Well Intervention (WI) operations, and can furthermore be used in other well operations too.

Rigless P&A in this method using CT, eliminates the need of cutting and pulling casing strings. Additionally, both XMT and a special CT BOP are rigged up all the time resulting in very safe operations for working personnel. Chapter 4.1.1 will elaborate further on the technical specifications of the CT.

3. The Regulatory Hierarchy on the NCS

This chapter gives a brief introduction of the regulatory hierarchy on the NCS and further present various regulations and requirements regarding P&A. The Petroleum Safety Authority (PSA) supervises health, safety, emergency preparedness and work environment of petroleum activities on the NCS. They further develop regulations and ensure that companies, both operators, contractors and vessel owners, comply with these [16]. Figure 3.1 presents a version of the regulatory hierarchy on the NCS.

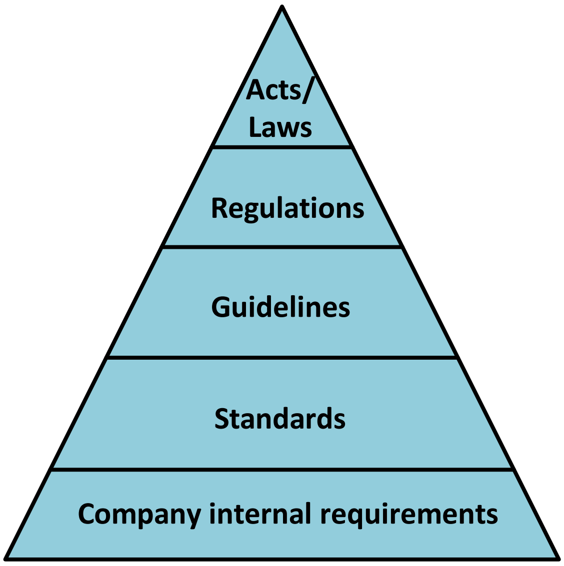


Figure 3.1 Regulatory hierarchy on the NCS

All petroleum activities are obliged to be executed in terms of rules and regulations given by the regulatory hierarchy. The regulations present *what* requirements and results the companies are expected and required to achieve from the various operations, not *how*. By doing so, the companies are free to choose how to execute an operation as long as the given requirements are fulfilled. This strategy also encourages the companies to indirectly investigate and develop new technology or methods. A positive outcome of this encouragement is the method presented in this thesis in which new areas of application of already existing equipment is investigated. Subsequently, PSA avoids the need of frequently updating the regulations owing to continuous technical development in the industry.

3.1.1 NORSOK D-010: Regulations and Requirements for P&A

Although several regulations, standards and guidelines exist, this thesis will cover the requirements regarding P&A addressed in NORSOK D-010 to limit the extent of the thesis. NORSOK D-010 was developed by the Norwegian petroleum industry with the purpose of defining requirements and guidelines to ensure well integrity during drilling and well operations. The standard was developed as an initiation to create a common set of operational requirements for the petroleum industry with the intent to replace individual company specifications [9]. The following subchapters will address the requirements given in the 4th revision of NORSOK D-010 with focus on well barriers.

3.1.1.1 Well Integrity

NORSOK D-010 defines well integrity as the "*application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well*" [9]. A wells life cycle is considered as the time interval from the realization of the well, until the well is permanently plugged and abandoned. It is crucial to ensure that well integrity is maintained throughout the lifetime of a well. At all stages during the lifetime of a well, well barriers are required to prevent leaks and diminish risks and thereby preserving well integrity. Establishing correct specifications and requirements for well barriers is dependent on several factors, such as wellbore geometry and condition (fatigue and corrosion), pressures and temperatures, cement and more. A large part of NORSOK D-010 revolves around establishment and verification of well barriers by introducing Well Barrier Elements (WBE) and acceptance criteria to fulfil given requirements and preserve well integrity.

3.1.1.2 P&A Well Barrier Philosophy

Defined in NORSOK D-010 as an "*envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation or to the external environment*" [9], a minimum of *one* such well barrier envelope shall be defined before starting any drilling, completion and P&A activities. Nevertheless, if the source of inflow is identified as a hydrocarbon bearing formation or a formation of abnormally high pressure with potential to flow to surface, a minimum of *two* well barriers shall be in place [9]. These two barriers are referred to as primary and secondary barriers, whereas the secondary barrier acts as back-up to the primary barrier should the primary fail.

Considering that the well barriers are the only objects separating the reservoir from the surface of the seabed, it is highly important that the barriers are capable of the following, but not limited to [9]:

- Withstanding all possible pressures and temperatures it may be exposed to throughout the lifetime of the well;
- Be pressure and function tested and verified by various methods;
- Withstand the external environment;
- Even if one barrier or barrier element fails, no uncontrolled flow to the environment of fluids or gases should occur.

A well barrier should be set as close to a probable source of inflow as possible to guarantee all leak paths are covered. Simultaneously, it shall seal both vertically and horizontally for eternal perspective. To ensure there is no leak path threatening the integrity of the well barrier, downhole equipment such as control lines must be removed. NORSOK D-010 specifically states that control lines and cables shall not form part of a permanent well barrier [9].

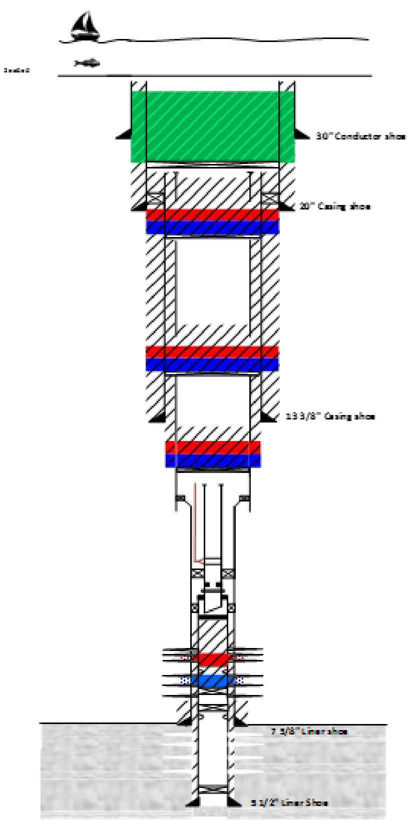
3.1.1.3 Well Barrier Schematics

Well Barrier Schematics (WBS) are created to illustrate the well barriers during an activity or operation such as drilling a new section, recompletion or workover and for final status of permanently plugged and abandoned wells. A WBS is of great help during planning and executing operations because it illustrates e.g. [9]:

- Well barriers
- Potential sources of inflow
- Reservoirs
- A table for writing important well integrity issues

Figure 3.2 illustrates the WBS for one of the wells in this thesis after it was permanently plugged and abandoned. The WBS template is provided internally from Aker BP. The blue barriers illustrate the primary barriers and the secondary barriers are illustrated in red. The green barrier on top is the open hole to surface well barrier, or surface plug.

Operator :	**Installation :**
Approved by :	**Well bore name :**
Checked by :	**Completed date :**
	Recompleted date :
	Revision no :
	Updated by/Date :
	Well details/ status :
	Reference documentation:



Well integrity problem(s)	*If any, indicated by ⇨*		●
Annuli	**MAASP, Psi**	**MOP, Psi**	

Well barrier elements	**Table ref.**	**Test pressure (PSI)/Date**	
Primary barrier			
Comments			
Secondary barrier			
Comments			

Csg & Liner	**Burst, Psi**	**Coll. Psi**

Well Integrity Comments:

Figure 3.2 WBS of a permanently plugged and abandoned well

Typically, the table on the right would contain information regarding the various barrier elements and their verification method. However, this simplified drawing is only provided for illustrative purposes to easier comprehend the intent of a WBS.

To avoid any future conflict with marine activities, NORSOK D-010 requires that the wellhead and casing strings are cut and removed below the seabed to prevent any equipment from surfacing in the future [9]. This is also illustrated in Figure 3.2.

3.1.1.4 Well Barrier Element

"*A physical element which in itself does not prevent flow but in combination with other WBE's forms a well barrier*" is the common definition of a well barrier element given in NORSOK D-010 [9]. A commonly applied understanding in the industry of this definition is given in the *Swiss Cheese Model* originally presented by psychologist James Reason. The model is widely applied in risk and HSE analysis, and management for whenever a situation requires more than one barrier to prevent unwanted situations [17]. Because a WBE alone does not prevent unwanted flow, several dependent WBEs would be required in P&A operations to avoid hazardous events to occur. Each barrier has a potential unintended weakness which in the *Swiss Cheese Model* is illustrated as the holes in the cheese, shown in Figure 3.3.

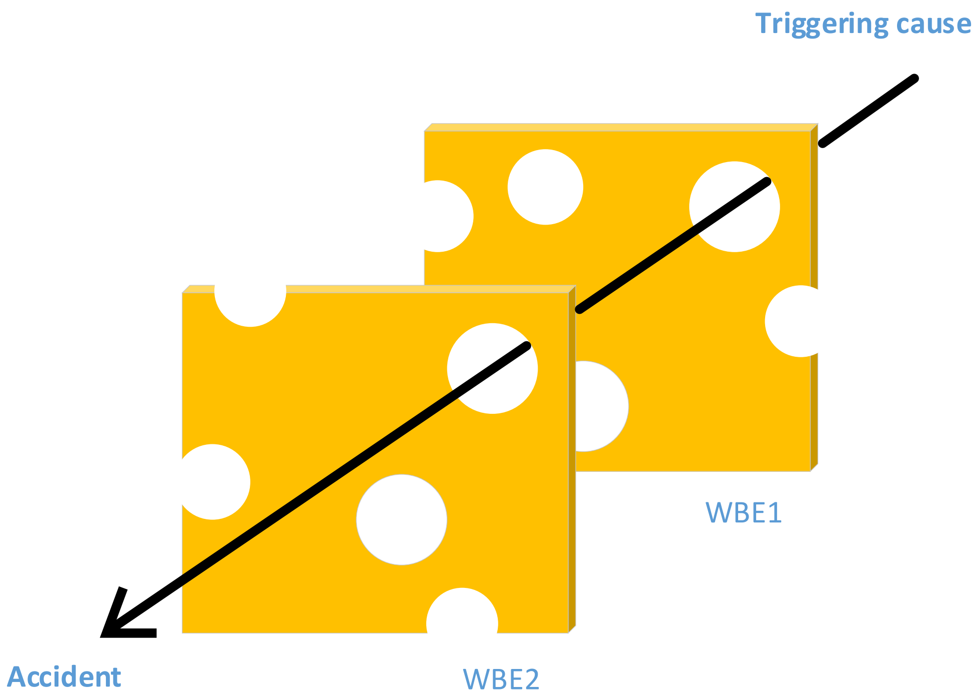


Figure 3.3 Swiss Cheese Model, inspired by [18]

These weaknesses are normally not constant. However, in some cases these holes may align and an accident could occur despite several WBEs. It is therefore highly important to ensure that the WBEs are designed and tested properly to limit these weaknesses.

According to NORSOK D-010 on page 96, a permanent well barrier composed of several WBEs should have the following characteristics [9]:

- Be impermeable
- Provide long-term integrity (for eternity)
- Be non-shrinking
- Be able to withstand all possible mechanical loads and impacts
- Be resistant to chemicals and other substances found downhole
- Ensure sufficient bonding to steel
- Not harm the integrity of steel pipes downhole

Common WBEs for P&A purposes are casing cement, casing and cement plugs, which could be interlinked to form a permanent well barrier when conducting PP&A.

Another frequently used understanding of how and why accidents may occur is the MTO model. MTO, which stands for Man, Technology and Organisation, includes two other dimensions compared to the Swiss Cheese Model, namely the human and organisational. The MTO model analyses the relationship between these three factors and uses the results for risk and HSE management purposes. The technological part is explained in the Swiss Cheese Model. The human factor includes education, experience and area specific training. An important part of the organisational factor is communication and being well-organised, e.g. communicating if a barrier is in place or not. Lack of any of these may lead to the cheese holes aligning and an accident could occur [18].

3.1.1.5 Well Barrier Element Acceptance Criteria

A WBE could be both external and internal, and must fulfil both technical and operational requirements to verify the barrier integrity. The external WBE must be verified to ensure that the barrier seals both vertically and horizontally as shown in Figure 3.4a). A typical external WBE is casing cement. NORSOK D-010 presents the following length requirements for an external barrier to qualify as a permanent barrier [9]:

- A minimum of 50 meter with formation integrity at the base of the interval.
- A minimum of 30 meter if the external barrier is verified by logging and the logs show acceptable bonding between the cement and formation, and cement and casing. This does not necessarily need to be a continuous interval of 30 meters; it can also be smaller intervals added together throughout a logged interval, as long as the sum is equal to or greater than 30 meters.

One of the most common internal WBEs are cement plugs. The internal WBE shall be set inside the casing across the entire interval of a verified external WBE as in Figure 3.4b). The following list is found in table 15.24 in NORSOK D-010 and describes the placement of the cement plugs and the corresponding length requirements [9]:

- *Open hole cement plugs:* 100 meter Measured Depth (MD) with minimum 50 meter MD above any source of inflow/leakage.
- *Cased hole cement plugs:* A minimum of 50 meter MD cement plug set on a mechanical foundation or cement plug. Otherwise 100 meter MD.
- *Open hole to surface plug:* 50 meter MD if set on mechanical plug. Otherwise 100 meter MD.

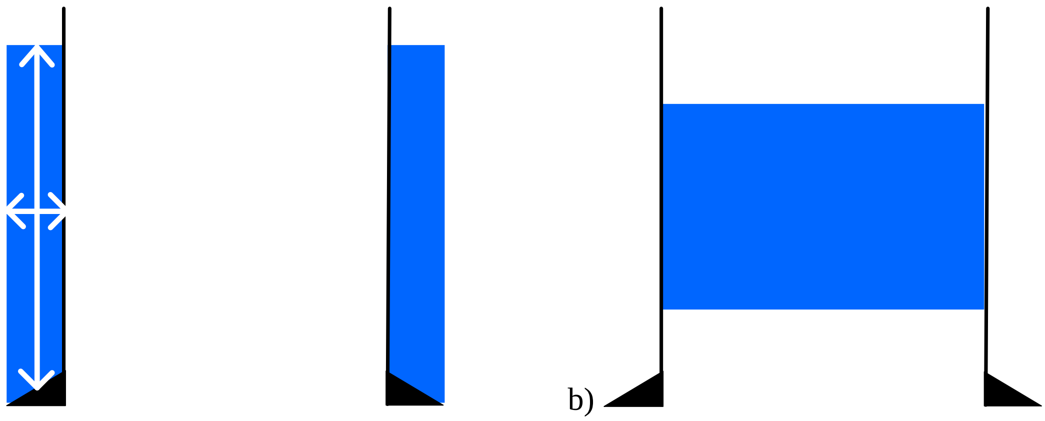

a) b)

Figure 3.4 a) External barrier b) Internal barrier

3.1.1.6 Verification of Permanent Barriers

It is important to perform tests on a well barrier in order to verify its capability of ensuring well integrity. When a well barrier or a WBE has been installed, a pressure test shall be executed to check if the barrier is capable of withstanding the maximum anticipated pressure it may be exposed to without fracturing. NORSOK D-010 accepts only leakage rates of zero [9].

In situations where formation is used as a WBE, tests shall be performed to verify the formation integrity. Listed below are the most common verification methods [9]:

- Pressure/Formation Integrity Test (PIT/FIT)
- Leak-Off Test (LOT)
- Extended Leak-Off Test (XLOT)

Because this is an important part of the thesis, the various methods are elaborated in Chapter 6.

Cement plugs are often used as WBEs. Both open and cased hole cement plugs may be verified by tagging. Tagging is the process of making contact with the cement plug by a tubing string or other equipment to verify its position. The cased hole plug shall also be verified by pressure testing. The pressure test shall be 1000 psi above estimated Leak Off Pressure (LOP) below a potential leak path [9]. Pressure testing may however damage the cement because it exposes the cement to stress, hence compromising its integrity.

3.2 Formation as Barrier

Some formations are more mobile than others. Creeping formations such as shale or salt, as these mobile formations are called, may be unfortunate during drilling operations because in severe cases it may deform the wellbore and cause several drilling issues [19]. However, during PP&A, creeping formation may creep towards the casing string in cases where there is no annular cement, and form an adequately sealing barrier. This is however only possible if the formation has sufficient flexibility and creep rate. The concept of *formation as barrier* could therefore be explained as the process of exploiting the mobile formation to plastically deform and surround the casing string to potentially form an annular barrier. While this is a process caused by natural forces, it qualifies as a much cheaper solution to P&A than the conventional cement barrier [20]. However, shale creep can also be induced by creating an underbalance in the well, which will be further elaborated in Chapter 6.4.

A permanent WBE must be impermeable. Permeability is a measurement of a materials ability to transmit fluids. The Earth is composed of different formations which are permeable in a variable degree. A common creeping formation is shale, which is known for its very low permeability, down in the Nano Darcy range. Shale and salt formations are known cap rocks for reservoirs, and has therefore already proven their sealing ability for millions of years. The cement used in oil wells on the other hand, has permeability in the range of 1-100 micro Darcy (μD), potentially making shale a more reliable barrier than cement [20]. Cement is also known to deteriorate and shrink over time, potentially creating leakage paths threatening the well integrity [21]. According to NORSOK D-010, creeping formation could be used to provide a continuous, eternal and impermeable hydraulic seal to prevent any unwanted flow of formation fluids as well as withstand pressures both from below and above. Listed below are the acceptance criteria for creeping formation [9]:

- Provide an eternal hydraulic pressure seal.
- A minimum of 50 meter MD of formation interval shall be identified.
- The minimum formation stress at the base of the formation shall be sufficient to withstand all possible anticipated pressures.
- The formation shall be able to withstand maximum differential pressure.

Like cement barriers, formation must be tested to determine its location and its sealing ability for it to qualify as a permanent well barrier. The information below is gathered from tables 15.51 and 15.52 in NORSOK D-010 [9]:

1. Location and length is verified by cement bond logs.
    - A minimum of 50 meter MD contact length with 360 degrees of qualified bonding.
2. Sealing capability is verified by pressure testing.
    - Pressure differential is applied across the formation interval.
3. Formation integrity shall be verified by a LOT.
    - Formation integrity shall exceed the maximum induced wellbore pressures.

If the formation has been qualified by the above tests, logging is considered adequate for subsequent wells.

4. Technology Used for P&A from Fixed Installations

The P&A operations on Valhall DP were performed by use of technology for other purposes than it was originally designed for. During implementing the proposed method, alterations in the tool selection were made to optimize it. This chapter presents the various equipment used for the method in this thesis.

4.1 Well Intervention

WI is implemented to extend the lifetime of producing wells, repair damage, or to increase the production in an underperforming well. Depending on the intervention operation to be performed, various WI equipment is available such as CT, WL and pipe string used for snubbing operations. Because CT was used for this particular operation, the following subchapter will elaborate further on this.

4.1.1 Coiled Tubing

A CT can be defined as a piece of continuous, flexible tubing that is stored on a rotating drum called a *reel* which is shown in Figure 4.1. The tubing pipe is straightened before it is lowered into the wellbore [22]. CT is normally made from low-alloy carbon steel with a yield strength in the range of 55 000 to 120 000 psi [23]. Being able to pump through the CT has given it unique opportunities in well services. The CT is also capable of performing work on live wells, which is the work it was initially designed for when it was developed in the early 1960's [24].

Operating on live wells is safer because there are no tool joints or stands to be made up. It is also faster because there is no need to bleed off the pressure. Because there is no need to kill the well, formation damage is avoided [25]. Because of small openings on the CT compared to a drill pipe, solids free fluids such as water must be used [26]. CT operations using water will create an underbalance in the well, because the hydrostatic fluid column is lighter at the bottom of the well compared to when using mud. The elements and barriers of CT allow for operating in underbalanced conditions. Operating underbalanced is known to minimize the potential of formation damage, which is another advantage of CT operations [27].

Advantages and challenges with CT is summarized in Table 4.1. CT provides efficient and safe operations, and has several areas of applications, including [28]:

- Clean-outs (Remove sand, fill etc.)
- Acidizing and Stimulation
- Gas lift
- Drilling
- Perforation
- Fishing operations

Advantages	**Challenges**
▪ Stronger than e.g. WL ▪ Can circulate fluid and rotate tools downhole while Running into Hole (RIH) or Pulling Out of Hole (POOH), (if motor is installed), providing a greater range of applications ▪ Can operate in live wells with pressure at surface → no need to pump kill fluid, hence the CT is environmentally friendly ▪ Small footprint on the environment ▪ Faster to rig up/down, reduced trip time compared to a rig ▪ Less personnel required compared to rig operations ▪ Cheaper than a drilling rig ▪ While using CT, rig may be used for other tasks simultaneously	▪ Heavy - not including the reel and gooseneck, the fundament weighs approximately 15 tons ▪ The CT is exposed to fatigue through plastic deformation bending because it exceeds its yield strength, and has therefore a relatively short lifetime ▪ Compared to a rig, the CT has less pull/push forces ▪ Mechanical failure including - Internal pressure loading - Compressive and tensile axial forces - Corrosion - Mechanical damage such as cuts ▪ Cannot be rotated from surface, only by installing a motor on the bottom ▪ Challenge to reach far out in the well resulting from buckling tendencies and friction

Table 4.1 Advantages and challenges of CT [23] [28]

4.1.1.1 Coiled Tubing Assembly Components

To be able to run the CT into a wellbore, an assembly of components is constructed. The main components are listed below and illustrated in Figure 4.1 [23] [28].

Power Pack - Hydraulic power from a diesel engine driven power pack is used to power the main components of the CT.

Control Cabin - Housing for a control panel which is an assembly of controls and gauges required to operate and monitor all components of the CT. The control panel activates the injector head and reel while also determining tubing direction and speed, and operational pressure for various components.

Reel - Used as both storage and transportation for the CT. Hydraulic power runs the reel while also ensuring tension between the reel and injector. A typical reel weighs approximately 20-40 metric tons.

Injector Head - Incorporates sets of profiled chains that run the CT either in or out of the well by gripping around the string. This is driven by hydraulic power which provides a tractive effort for both driving the coil into the wellbore and retrieving it.

Gooseneck - Mounted on top of the injector head, the gooseneck guides and feeds the coil from the reel and into the injector head. Typically weighs 8-12 tons.

Pressure Control Surface Stack - Consists of strippers, CT BOP, XMT, and a safety head [28].

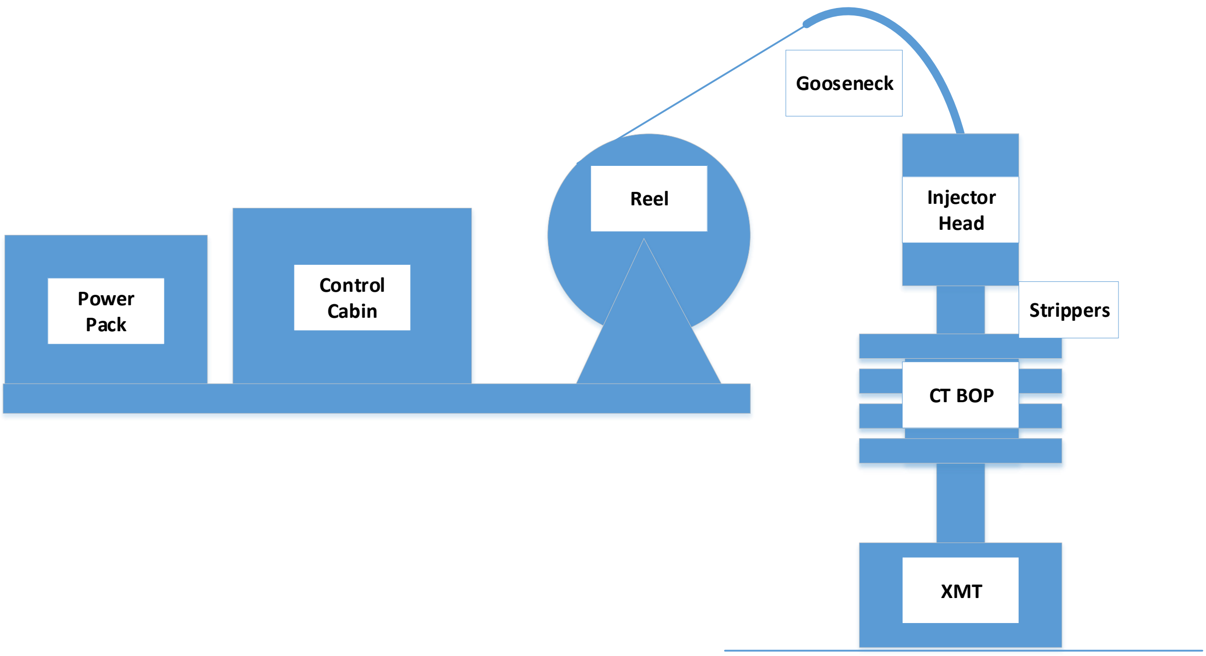


Figure 4.1 Elements of a Coiled Tubing

4.1.1.2 Barriers During Coiled Tubing Operations

As for all petroleum operations and activities, verified well barriers are highly important when running a CT to ensure well integrity. Various equipment with sealing abilities against hydrocarbons and pressure may serve as a barrier during operations. Because the CT is run through the XMT, other barriers are required in addition to the frequently used barriers in a well. Cement, casing string, in-situ formation and the XMT are all examples of frequently used barriers. Additional barriers during CT operations could be:

Strippers (Stuffing box) - Strippers are classified as a primary barrier, because they act as operational seals between the pressurized wellbore and the surface. Strippers consists of a stripper rubber and an energiser. There are two strippers in place, one upper and one lower stripper. During operations, the upper stripper is active whilst the lower stripper acts as a backup if, for instance, the upper stripper should need a new rubber element. The stripper rubber is the sealing element during any CT or snubbing operation. Being a consumable element, the stripper rubber is frequently replaced, normally before every operation. Hence, it is advantageous that the stripper rubber can be replaced while the tubing is in place and therefore also during an operation [23].

BOP - Situated below the strippers and above the XMT, is the CT BOP. Depending on the number of rams the BOP consists of, it is either a single, double, triple or quad BOP assembly. The BOP ensures well control because the various rams can close or hold the pipe in different manners in case of an emergency. A kill port is situated between the two upper rams. If it becomes necessary to kill the well, kill mud is pumped through this port. The body of the CT BOP with kill port is classified as a primary barrier.

Safety Head - As a last option, a safety head is installed serving as a well barrier because it can cut pipes and seal off the wellbore in case of an uncontrolled situation.

4.2 Equipment Used During the Implementation of the Proposed Approach

This chapter provides theoretical information about various equipment used during the operations of the proposed approach. Because the proposed method is an ongoing learning process for Aker BP, different equipment has been tried in order to identify which equipment will ensure the most efficient method with highest success rate.

Bridge plug - Is a mechanical plug acting as a seal installed inside the casing strings. There are several types of bridge plugs, and they may be permanent, retrievable or repositionable. The permanent bridge plug is not designed for being removed intact and must therefore be destroyed should it be necessary to pass through it. The retrievable bridge plug is designed to be retrieved if necessary by e.g. CT or WL. Finally, the repositionable bridge plug is defined as a retrievable bridge plug designed to be relocated inside the casing and is designed to restore its functions after relocation [29]. As mentioned in Chapter 3, cement can be set on a mechanical foundation, e.g. a bridge plug, when constructing a permanent well barrier. This is performed to minimize contamination [7].

Packer - A packer is a device used to seal a well internally. The packer obtains its sealing ability by expanding once located at desired position downhole by e.g. CT or WL. Packers may be permanent or retrievable. Permanent packers should be composed of material that can be easily drilled through at a later stage should it be necessary [30]. Different packers have been used during the attempt of creating a new method for barrier restoration across dual cemented liners.

One of the packers is the Inflatable Jet Set Packer (IJSP), also known as a stimulation packer. Although the stimulation packer is not designed for pressure sealing, continuously pumping of fluid could keep the packer inflated and maintain its sealing properties. It is possible to pump through this plug, which is an advantage for subsequent injection tests. This continuous flow of fluid did however affect the flow tests performed during the proposed method and created confusing results [26]. This should be considered when using this packer for future tests.

Another packer that was tested during this method was the Inflatable Retrievable Production Packer (IRPP). As the name reveals, this plug is both inflatable and retrievable, and can be used to seal off a wellbore. The plug may also be used for pressure measuring purposes, in which a memory pressure gauge is hung from the plug and set downhole [26].

Perforating gun – Is a device that is typically used for preparing a well for production, by creating holes in a casing string which extends into the reservoir. Perforating guns could be either tubing conveyed or wireline conveyed [4]. A Tubing Conveyed Perforating (TCP) gun was used for this method because it was desired to perforate long intervals in one run. The perforation gun is lowered into the well attached to e.g. a CT and may be triggered by either flow, pressure signals or a timer. Another version of the TCP is the tandem TCP, which contains two sets of guns making it possible to create two perforation sets in one run. Once the first perforation set has been shot, a signal is sent to the second perforation gun which will shoot the second perforation set after being triggered [26]. This is an advantage in the proposed approach should the communication test fail, because instead of having to perform a second run with a loaded TCP, the CT is instead hoisted to perforate another zone higher up.

5. Valhall DP and P&A Challenges

Aker BP is a fully-fledged exploration, development and production company with activities on the NCS. The company is one of the largest independent oil companies in Europe when measured in production. Since October 2017, Aker BP became the sole owner of both the Hod and Valhall fields. The latter has been producing since 1982 and will be the field of focus in this thesis. In December the same year, Aker BP sold 10% of Valhall and Hod shares to Pandion Energy AS, and is therefore currently the operating company on the fields holding 90% of the shares [31].

5.1 Aker BP and Valhall

Figure 5.1 shows the Valhall field which is located on the southernmost end of the NCS, approximately 290 kilometres south of Stavanger. The field, which is found in blocks 2/11 and 2/8, turned out to be the fourth commercial find on the NCS up to this date when it was discovered in 1975. Located in an area of 70 metres water depth in the oil-rich Ekofisk area, the field was initially developed with a living quarters platform (Valhall QP), a drilling platform (Valhall DP) and a process and compression platform (Valhall PCP). A wellhead platform (Valhall WP) and an injection platform (Valhall IP) were later installed on the field development to increase the number of slots and to carry water injection equipment [32]. The field is operated with two Unmanned Wellhead Platforms (UWHP) on the flanks, also referred to as Normally Unmanned Installations (NUI). This is shown in Figure 5.3.

Figure 5.1 Location of Valhall and Hod [2]

The Hod field is located 13 kilometres south of Valhall as a part of the Valhall area. The field is developed with an unmanned wellhead platform and is remotely operated from Valhall [33] (Original text in Norwegian).

5.2 Reservoir

When the Plan for Development and Operation (PDO) was presented for the Norwegian government in 1977, the estimated content of the Valhall field was approximately 250 million barrels of recoverable oil. Nevertheless, from production start in 1982 up to 2014 it had yielded close to one billion barrels of oil equivalents with prospect of recovering half a million more [33].

The field is an anticline which produces from the soft chalk Late Cretaceous Tor and Hod formations found at approximately 2500 metres Total Vertical Depth (TVD). The Tor formation is fine-grained and a soft chalk rock of high porosity, allowing for considerable fracturing of the formation. Being easily fractured, the Tor formation allows oil to flow easier than in the Hod formation. The porosity of the Valhall area is in general high, with the highest porosity of 54% measured in the field, meaning the rock contained more fluid than rock itself [32].

Although the porosity is high throughout the area, the measured permeability in the range of 0.1-15 mD is considered very low, where the lowest value is found in the Hod formation. Permeability is a measurement of how easy fluids can travel through a material, meaning the low permeability may therefore pose a challenge regarding the recovery factor of the field. The permeability in the formation decreased from its initial value because of severe compression of the chalk rock from the overburden [32]. One of the reasons for the compression was gas escaping from the reservoir. While gas was escaping, the overburden pressure was increasing, subsequently preventing the reservoir rock from consolidating properly. With the poor consolidation, the reservoir became compacted which further led to subsidence of the above seabed [34].

5.3 Subsidence and Further Development

Depletion of the chalk reservoir throughout the years had led to reservoir compaction and subsequently subsidence of the seabed above the Valhall field. Reservoir compaction is in general a good contributor to increased recovery factor. Nevertheless, when the compaction reaches a certain magnitude it could lead to casing deformation and in worst case well collapse [35].

Severe compaction of a reservoir can lead to seabed subsidence and pose a large threat to offshore constructions such as platforms and pipelines [35]. From production start in 1982, the subsidence rate of the Valhall area was for a long time 25 cm/year as can be seen in Figure 5.2. The water injection platform (Valhall IP) which was installed in 2003, contributed to lower the subsidence rate and at the same time increased the recovery factor of the field. The original platforms were not designed for such severe subsidence, and because the seabed had sunk 6.7 metres since 2016, the air-gap from the platform deck to sea became dangerously small [36].

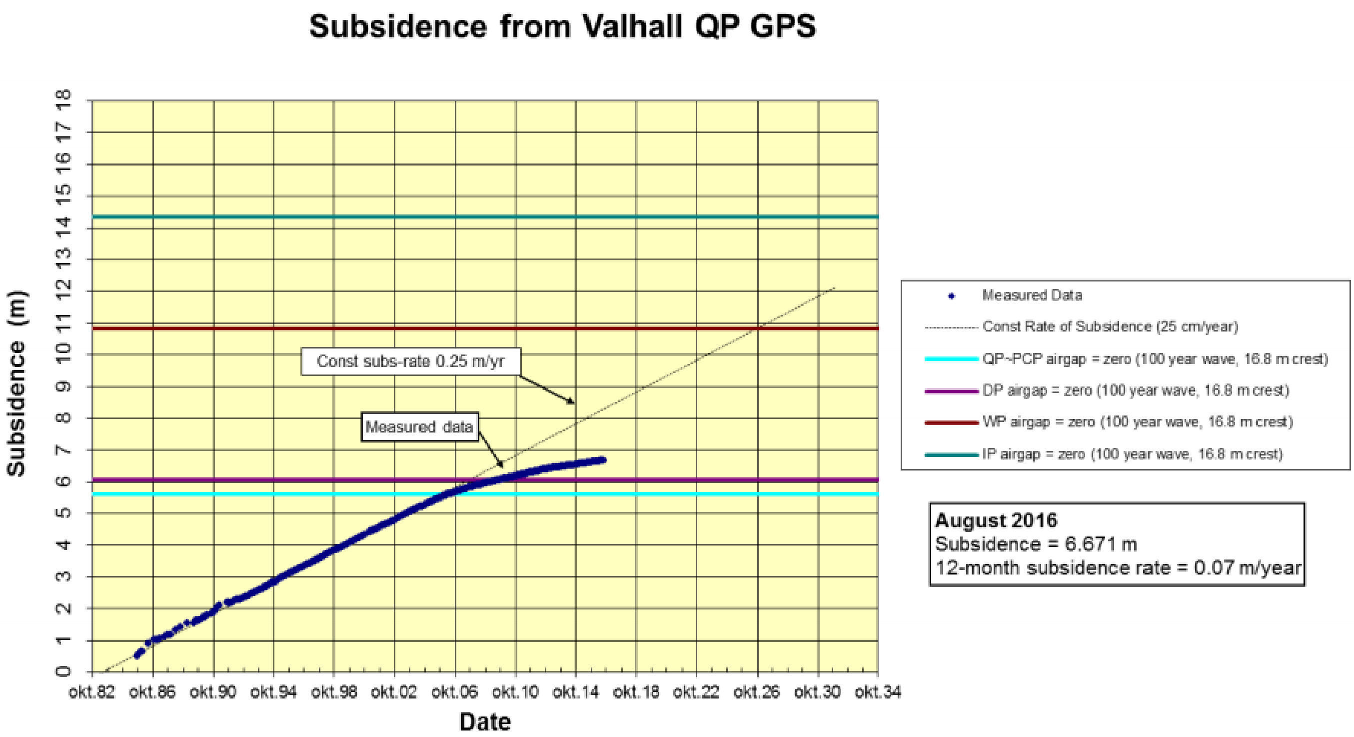


Figure 5.2 Subsidence data from the various Valhall platforms [37]

A re-development of the area was therefore initiated, and in 2012 an integrated production and hotel platform (Valhall PH) was installed. With the subsidence in mind, Valhall PH has a greater air-gap from the sea compared to the older platforms as seen in Figure 5.3.

Since this platform was installed, Valhall became the first field on the NCS to be converted from locally diesel generated electricity, to being powered from shore [33]. Figure 5.3 displays the various platforms on the Valhall area with the overburden and various Distinct Permeable Zones (DPZ) (numbers 3 through 9) below the seabed, where DPZ 9 is the reservoir.

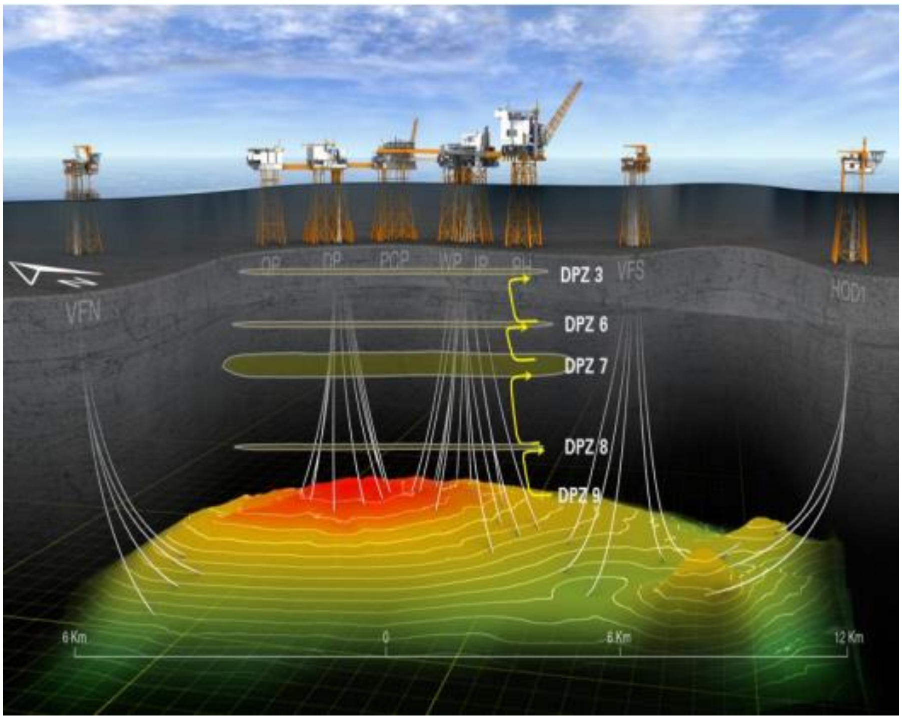


Figure 5.3 Valhall and Hod [2]

Although actions had been taken to lower the subsidence rate, the subsidence of the seabed had lowered the original platforms too far making them unsafe because they could be destroyed in the event of a 100-year wave [38]. The original platforms must therefore be removed and the wells extending from them must be plugged and abandoned. One of these platforms is Valhall DP. The next subchapter will consider the standard casing program of the Valhall DP wells in the reservoir section, and what challenges this particular well design and geology introduces regarding P&A.

5.4 P&A on Valhall DP

5.4.1 Casing Deformation Challenges

The weak chalk formation in the Valhall area represents a key predevelopment issue and is considered to be the main reason for plugging the wells of Valhall DP. Another challenge the soft chalk formation has caused, is the risk of casing deformation and wellbore collapse. When developing a plan for casing design, there are several factors that must be considered to avoid issues such as casing deformation [39]:

- The purpose of the well, the surrounding geology, available casing sizes, rig performance and HSE regulations.
- The casing design must account for all anticipated loads the well may be encountered to during the lifetime of a well to ensure well integrity is maintained.
- Casing strings should be designed cost-effective such that cost is minimized, and at the same time meet design criteria and not compromise well integrity

To select the appropriate casing design, certain criteria must be established and followed. These design criteria consider various load cases and the appropriate design factors corresponding to each particular casing design. Casing strings are exposed to enormous forces downhole, and should amongst several load cases be designed for burst, collapse, axial tension and compression loads. Other than reservoir compaction and subsidence, these loads come from phenomenon such as production of solids, tectonic loads, earthquakes or large thermal fluctuations like injection, which may be both cooling and heating [35].

Another important aspect to consider regarding casing deformation is the wellbore geometry. Horizontal wells have a higher risk of collapse compared to vertical, because horizontal wells are parallel to the overburden and are subjected to large stresses and loads. Cementation of horizontal casing strings can also be challenging, especially if the casing string is de-centralized in the well. If little to no cement is present on the high-side of the string, the above-surrounding formation may subsequently compact owing to the overburden, and consequently deform the string leading to well failure [3].

An analysis of Valhall field data indicated several reasons for well failures in the reservoir [35]:

- Shear loading of casing string in the overburden
- Cross-sectional collapse

- Buckling failures

The chalk in Valhall would move while compacting, resulting in deformation and subsequently collapse because the casing strings were not designed for such loads. The degree of casing deformation depends on casing design, formation properties, as well as the strength of the cement bond between casing and formation. Deformed wells are difficult to access and is a known challenge worldwide. In serious cases the reservoir section could be in-accessible [40].

To prevent casing collapse in the reservoir section, all wells in the Valhall area had to be re-designed and were now completed with heavy walled liner overlaps after 1995 to optimize the Diameter/thickness (D/t) ratio [40]. Heavy walled casing strings have a lower D/t ratio and a greater weight compared to conventional casing strings, making them more resistant to movement in the formation and the associated loads from the reservoir. The 7 in. liner shoe is set just within the reservoir, and the thicker 5 in. liner is then cemented inside the 7 in. liner, further extending into the reservoir, as seen in Figure 5.4. This applies for two of the three wells considered in this thesis, because one of the wells was completed with a conventional 5 in. liner inside the 7 in. liner. Use of heavy wall liners do nevertheless, introduce challenges regarding installation of the casing string because the clearance from the wellbore wall and outer casing is small, not to mention the increased torque and drag forces that will occur [26].

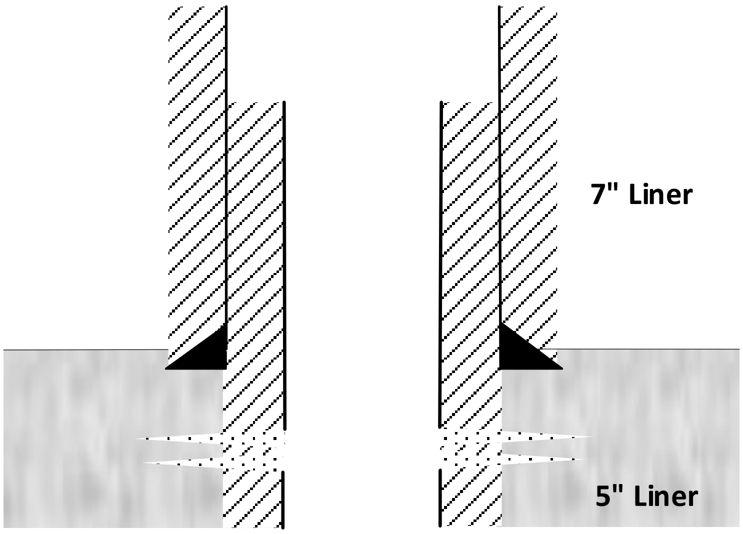


Figure 5.4 Dual Liners extending into reservoir

As previously described, there is no logging tool available today that can log through two overlapping casing strings to verify sufficient cement bond as per requirements. The common procedure is then to perform section milling of the inner casing. Compared to logging, this is time consuming and costly, and not to mention a potential HSE risk regarding swarf handling on surface, and the challenge with a thick-walled liner. The proposed method presented in this thesis avoids this by perforating intervals with a CT, and further perform XLOTs and communication tests through the perforations to verify no communication either in the liner annulus nor between the perforations. Both the conventional method and the proposed approach for barrier verification are further elaborated in separate chapters.

6. Determination of Formation Integrity

To fully understand the proposed approach for barrier verification presented in the thesis, a theoretical introduction of various formation integrity determination methods will be presented in this chapter. There are several methods that can be used to determine formation strength and integrity to qualify a formation as a WBE. Formation Integrity Test (FIT), Leak-Off Test (LOT), Extended Leak-Off Test (XLOT) and communication test are all common methods used for this purpose, however, the tests have different objectives for when being used [9]. The tests are normally conducted during drilling of a well, but can also be performed at later stages such as P&A to ensure well integrity [3].

6.1 Formation Integrity Test

An FIT is conducted to evaluate the strength and integrity of a formation by applying a pre-planned pressure through injecting fluid into the well, further compressing it and then monitoring if the outside formation remains stable. The information gained from such tests is of great importance because it could be used further during the lifetime of a well to determine casing setting depths, well control options, fracture pressures and fluid weights [41]. There are several reasons for performing an FIT. One of the reasons is to evaluate the cement bond strength surrounding the casing shoe to ensure there is no communication with surrounding formations. The FIT evaluates the highest pressure achieved during a limit test, and determines the ability of the formation to sustain up to this particular pressure without losing any fluid [41] [3]. The FIT lies on the linear part of the pressure vs. volume plot just below the LOP as seen in Figure 6.6. Because the FIT only tests up to a certain pressure, it gives no information of pressures above this pre-set pressure. A LOT or XLOT could be performed to test the formation further.

6.1.1 FIT Scenarios

An FIT could be a good indication of the pressure the various formation zones can handle downhole, but nevertheless there are several uncertainties with performing this test that should be considered. Figure 6.6 displays a dotted line which is extending from the linear line from the point of LOP. This is called a control line, and is created by performing an FIT before drilling a new hole section, also called a casing test. A control line could be considered as a guiding line to what our FIT in open hole should be like, because the linear line should follow the control line. An exception is if the injection fluid has been altered between the casing test and the following open hole FIT [3]. Presented below are some pressure responses that may occur during FITs.

6.1.1.1 Ideal FIT

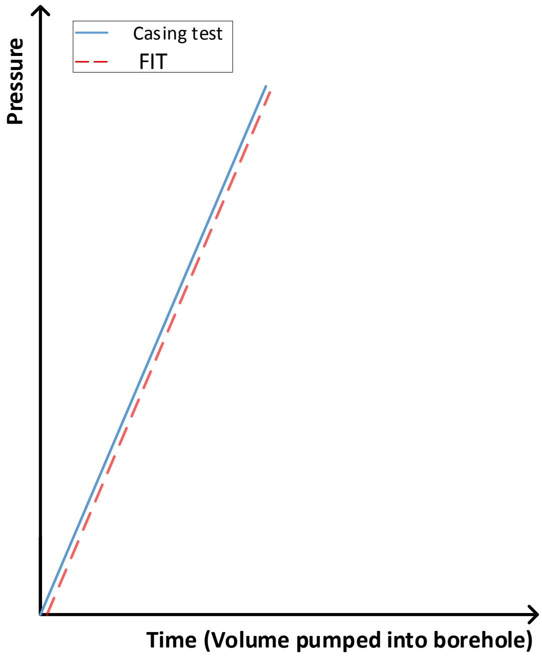


Figure 6.1 Schematic of an ideal FIT plot

In Figure 6.1, the FIT pressure response is almost identical to the casing integrity test, which indicates a good FIT. The FIT has a slightly more compressible response, i.e. lower slope, caused by extra hole length and exposed formation compared to cased hole in the casing test [3].

6.1.1.2 Bad FIT Caused by Air or Gases in Pipes

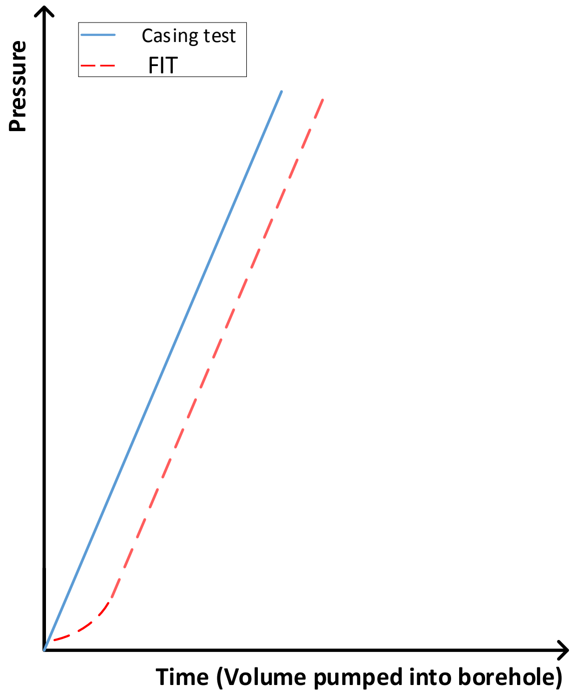


Figure 6.2 Bad FIT cause by air, gas or still, compressible fluids in pipe lines

A large volume of air, gases, or less specifically still, compressible fluids in the pipe system, could cause trouble when performing an FIT. It is therefore important to compress this before continuing with the FIT. Air, gas or still, compressible fluids in a pipe can be identified by a relatively flat FIT pressure response during the first barrels that are pumped into the well, which can be seen in Figure 6.2 [3].

6.1.1.3 Bad FIT Caused by Poor Hole Cleaning

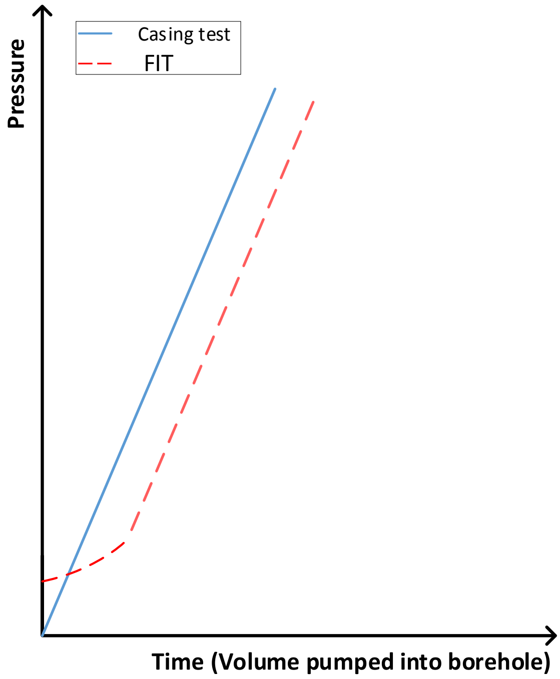


Figure 6.3 Bad FIT caused by poor circulation job

If the circulation job prior to the FIT was not successful, there is a risk of residues downhole interrupting the results of the FIT. There will be some pressure downhole which will create the FIT curve seen in Figure 6.3 [3].

6.1.1.4 Bad FIT Caused by Formation Related Issues

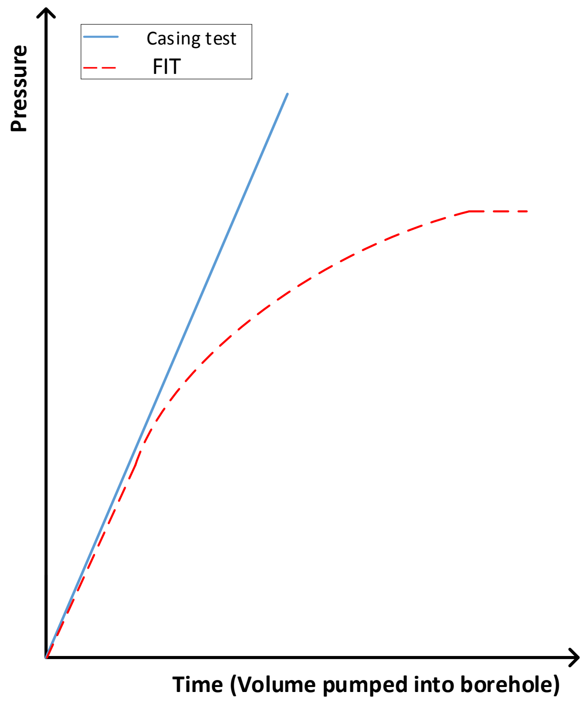


Figure 6.4 Bad FIT caused by formation related issues

Figure 6.4 displays an FIT where the injected fluid is leaking out into the formation at such high rates that the pressure build-up deviates away from the casing test curve. Subsequently, a LOP is impossible to select. This plot and similar plots may occur when fluid leaks out owing to a sand zone. Sand zones are normally blocked by the drilling mud, but exceptions can occur. Other reasons could be re-opening of a fracture or expansion of formation [3].

6.2 Leak-Off Test

Casings are set while drilling into regions with higher pressure. After setting a casing, 3-7 metres of open hole is drilled. A LOT is then performed, assuming the casing shoe is the weakest point [3]. A LOT is executed to establish the maximum pressure the open hole walls and casing cement can support. It also assesses the formation integrity. The data obtained from such tests could furthermore be used beyond its intent, such as for stress estimations during exploration and drilling [42].

Some benefits of performing an LOT are:

- Provide estimates of minimum horizontal in-situ stress, S_{Hmin}.
- Detect channels and determine where and when it would be beneficial to perform squeeze cementing.
- Reduce risk of circulation loss.
- Improve estimates of mud-weight window for drilling operations.

Forces in the Earth are quantified as stresses and at depths within the range of drilling bits in most parts of the Earth, two stresses can be defined; vertical in-situ stress, S_V, and horizontal in-situ stress, S_H. "In-situ" could be defined as on site or local. The vertical stress acts vertically on a horizontal plane, which then obligates two stresses acting in a horizontal direction. The two stresses are identified as the minimum in-situ horizontal stress, S_{Hmin}, and the maximum in-situ horizontal stress, S_{Hmax} [43]. The stresses have contrasting magnitudes and directions as seen in Figure 6.5.

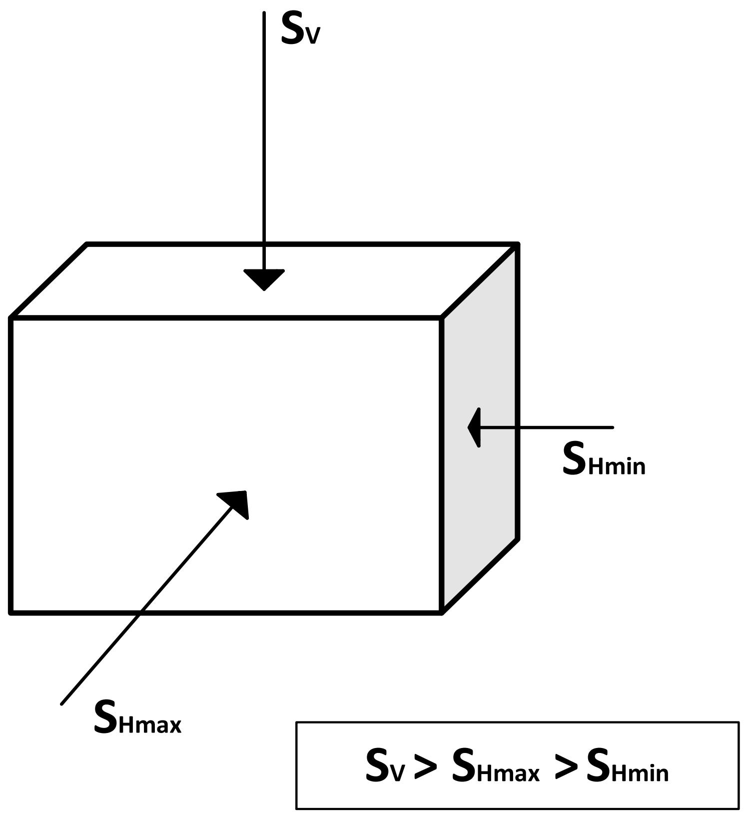


Figure 6.5 In-situ stresses, inspired by [44]

The in-situ stresses are caused by gravitational loads, plate tectonic driving forces, as well as human impact from drilling, production and injection. The vertical stress is also referred to as overburden stress because it compresses the underlying rock. The magnitude and direction of the stresses are important because they provide information regarding the pressure required to induce and propagate a fracture as well as the shape, direction and extent. By performing LOTs, it is desired to estimate the minimum horizontal in-situ stress as a hydraulic fracture will propagate perpendicular to S_{Hmin} [44]. An estimation of S_{Hmin} is needed during well abandonment because it determines the critical depth or minimum setting depths, of permanent downhole plugs [45].

6.2.1 LOT Procedure

A LOT is performed by applying pressure and evaluating how much pressure the formation can hold before it breaks. The well is pressured up by injecting fluid either through e.g. a CT, drill pipe or through the XMT. The wells in the case study are perforated with a minimum of two sets of perforations, and the injected fluid is pumped into each of the sets where it is further compressed. Pressure is measured at surface at the wellhead in a closed-off well by monitoring for pressure build-up or returns in the annulus [46]. To get accurate pressure data from each perforation set, an inflatable bridge plug should be set between the perforations to isolate them from each other internally. During a LOT, the formation is pressurized for a short period of time such that a LOP is obtained, as seen in Figure 6.6. A linear line is desired, and should the line deviate, further investigations should be conducted. Examples of this are given in the previous subchapter.

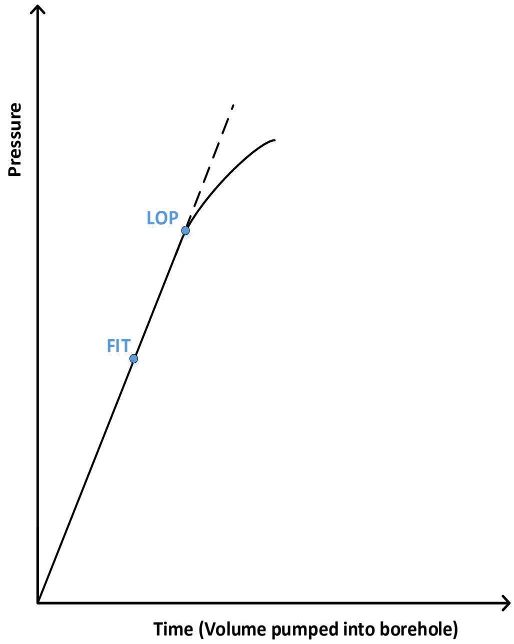


Figure 6.6 Schematic of a Leak-Off Test

Figure 6.6 shows the desired result from a LOT. The LOP is found where the linear line breaks off. It is desired that the LOP is equivalent to the fracture pressure of the cap rock because this implies one is "talking" to the formation. The LOP is nevertheless difficult to define because it could also occur as a result from expansion of the formation [3].

6.3 Extended Leak-Off Test

Both LOTs and in particular XLOTs are widely used to estimate values of the minimum horizontal in-situ stress, S_{Hmin} [47]. Since a LOT does not test the formation beyond the Formation Breakdown Pressure (FBP), an XLOT could be performed instead when a higher level of assurance is required. This can also eliminate or reduce uncertainties related to the conventional LOT.

An XLOT will provide more accuracy of the magnitude of the S_{Hmin} because the test is a LOT extended past the FBP. The FBP is the pressure required to fracture the rock matrix inside a formation. While pumping fluid into the formation, vertical tension in the formation decides what pressure the formation breaks down at. The XLOT should be repeated in two cycles, because the second cycle will confirm the pressures observed from the first cycle. By doing so, one is able to assess what went wrong in case the pressure responses are not as expected or not repeating themselves throughout both cycles. Each repeated injection is referred to as a cycle. Figure 6.7 illustrates a graph obtained from performing an XLOT. The pressure labels are added for informative purposes. This figure is theoretical, and it is not guaranteed that an actual XLOT will display identical characteristics [3] . The pressure responses are measured at surface.

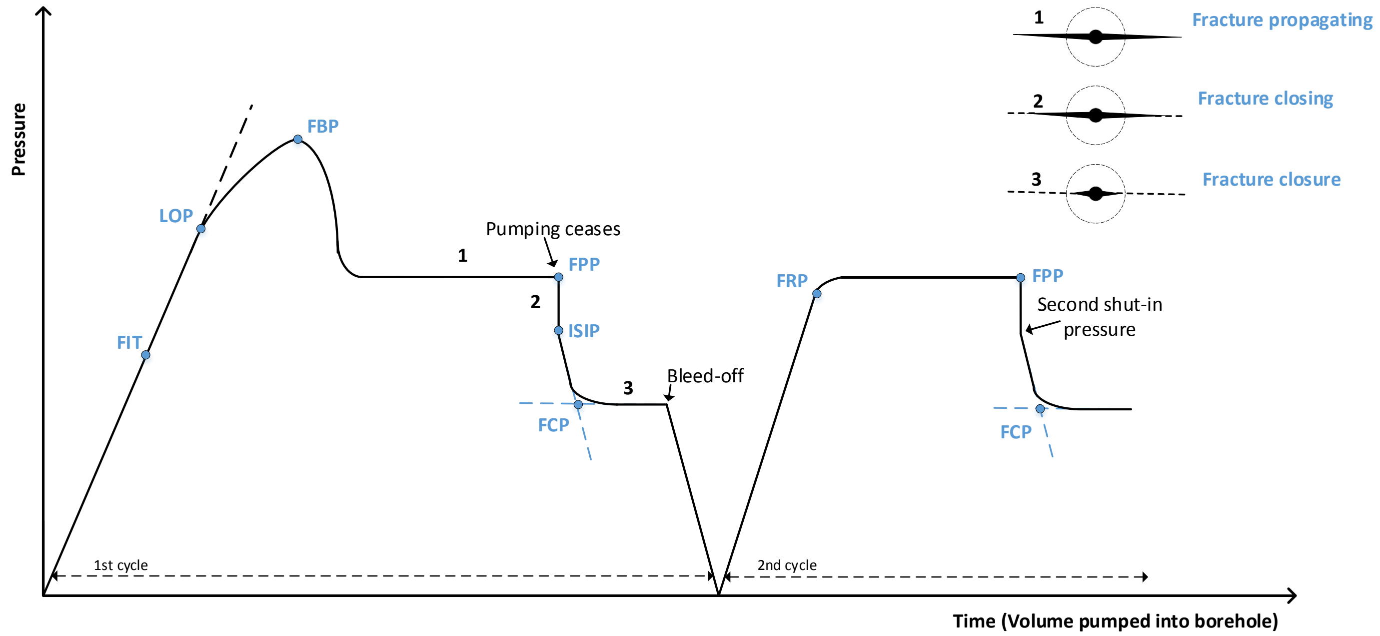


Figure 6.7 Schematic of an Extended Leak-Off Test

At the point of LOP, a fracture initiates at the wellbore wall, causing a change in compressibility of the overall casing and open hole interval. The pressure will continue to increase until the pressure induced fracture begins to propagate in an uncontrolled manner away from the borehole. This pressure is the FBP, which will be the highest measured pressure during an XLOT as seen in Figure 6.7. Once the formation is fractured, some of the liquid will leak off into the formation. The measured pressure will then decrease and become constant while pumping continues. The constant pressure is referred to as the Fracture Propagation Pressure (FPP).

When pumping ceases, loss of friction in the pipe will decrease the FPP to a pressure called Instantaneous Shut-In Pressure (ISIP). With low pumping rates, the pipe friction will have little effect on the pressure drop and the ISIP will be very close in magnitude to the FPP. The final pressure obtained during an XLOT is the Fracture Closure Pressure (FCP) [3], which is where the fracture closes again.

According to NORSOK D-010 this pressure is equal to the minimum horizontal formation stress (S_{Hmin}). The S_{Hmin} is difficult to determine, but may be found at the intersection by drawing trend lines as illustrated in Figure 6.7 [9]. This pressure may also be referred to as the shale closure pressure because the perforations are shot inside a shale cap rock.

After pumping ceases, the well is kept closed and the pressure will subsequently level off and stabilize at a constant value. If it levels off and stabilizes at the expected $S_{Hmin,}$ it indicates a sealing formation, however, if the pressure levels off to a pressure below $S_{Hmin,}$ e.g. reservoir pressure or pore pressure, it would indicate communication with either a reservoir or a highly permeable formation. This is not desired because there is a risk of communicating with the reservoir if the formation has high permeability [48]. The pressure is subsequently bled off, before another cycle is repeated.

When fluid is pumped into the well to perform the second cycle, a Fracture Reopening Pressure (FRP) will occur once the fractures reopens. During an XLOT it is desired that the magnitude of the pressures in each cycle are repeated. As can be seen in Figure 6.7, the FBP in the first cycle does not repeat itself in the FRP in the second cycle. This could occur resulting from leaks when the fracture reopens again, or as a result of the fracture being weaker when it has been opened once before and therefore requires less pressure to reopen. It should be mentioned that the FBP is not necessarily present in the first cycle either, however, there are no given requirements in NORSOK D-010 for this pressure to occur [3]. There are furthermore no requirements in NORSOK D-010 regarding the number of cycle repetitions [9]. As a simplification, it can be concluded that an XLOT is executed to check if the formation rock is good by verifying its strength and integrity. It also identifies repeatable pressure values giving more understanding of the competence of the formation being tested.

6.3.1 XLOT Procedure

The description of the XLOT procedure below is based on information gathered from several meetings with Daniel Tomczak and Roar Flatebø. As mentioned in Chapter 6.2, the wells in the case study are perforated with at least two sets of perforations by a CT rigged with a TCP gun. Fluid is then pumped through the well and into one perforation set at a time. All perforation sets are tested separately by an XLOT to confirm open perforations and to check the formation strength and integrity. The XLOT will also indicate if there is any communication with permeable zones [48].

Figure 6.8 shows the first perforation set (Zone 1), which is shot a minimum of 50 meters above the reservoir, because this is the length requirements of a permanent external barrier, as well as for a cement plug, given in NORSOK D-010. Prior to this, the well is internally sealed by an inflatable bridge plug which is set above the reservoir. A bridge plug is also set to isolate internally between every perforation set. Using the same principle as the LOT, the well is pressured up by injecting fluid through the XMT or through the CT and into the perforation set. The well is pressured up to FBP, and the pressure response is measured at surface by monitoring for pressure build-up in a closed-off well. The procedure is then repeated for each perforation set until both a primary and a secondary barrier have been established and verified by using the chosen method [3].

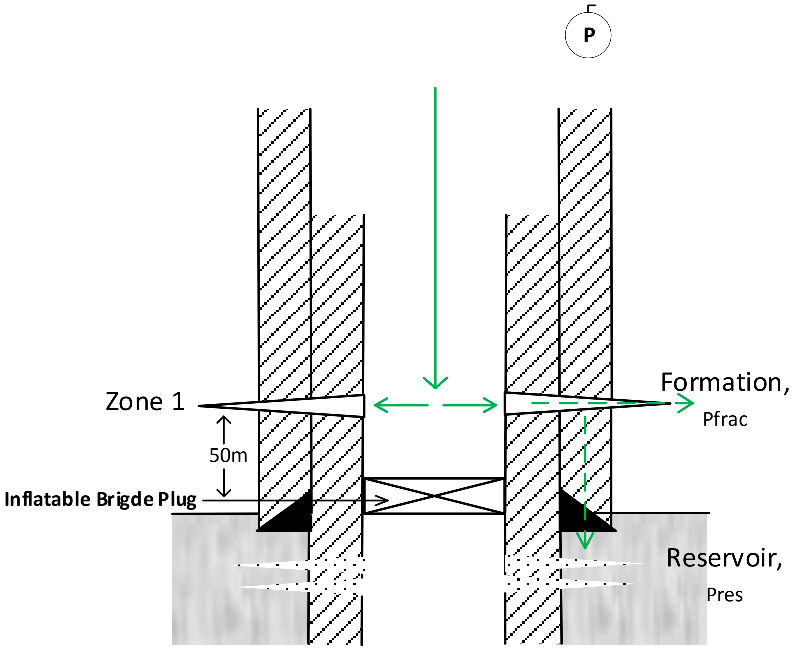


Figure 6.8 XLOT through lowermost perforations

The pressure in a reservoir that has been produced will be less than the fracture pressure in the surrounding formation. Nevertheless, the reservoir pressure will over the eternal perspective of P&A build up and increase, and the barriers that are established downhole must be able to withstand all maximum anticipated pressures and loads. Although the pressure build-up may take several hundred years to reach maximum, barriers must withstand these pressures for eternity. The purpose of performing the XLOTs is therefore to evaluate if the cement interval from the perforations down to the reservoir is capable of withstanding these, and thus it must be evaluated what pressures the XLOT leaks off to.

If the XLOT levels off to FCP, it is satisfactory that the barrier can withstand the future anticipated pressure, and the 50 meter interval is confirmed as a qualified barrier as per requirements. These anticipated pressures are estimated prior to the operations in Phase 0. If the pressure levels off to reservoir pressure there could be a potential leak path to the reservoir and the barrier is not acceptable.

The injected fluid used for the tests varies depending on what is already used in the well. Nevertheless, the fluid can be changed if another fluid is desired for the XLOT. For the three wells considered in this thesis, water was used to open the pre-shot perforations. Water has the ability to enter all possible paths and pores owing to its characteristics. This makes the XLOT more advanced because water will reveal any communication between the perforations and the external environment. Using water will also easily reveal any hydraulic communication with the reservoir. By comparison, mud may block up any pores because it is thicker and denser, possibly making it more challenging to verify any communication between the perforations. Water removes the uncertainty because it does not block any pores [26].

If the 50 meter interval from the perforations to the reservoir is not qualified as a barrier, it will be quickly recognized when evaluating fluid returns at surface. This is because the water would leak into the formation as multiple of the locations at Valhall would not be able to hold the hydrostatic water column if a leak is present. Because water is used for testing, it would not be possible to build pressure during an XLOT in case of a leak. The injected fluid would leak into the formation and down to the reservoir, and the pressure read at surface would therefore be equal to zero and no XLOT graph would be obtained [49]. If the well is not sub-hydrostatic, i.e. low bottom hole pressure, it will still have reservoir pressure lower than the cap rock pore pressure. Because the reservoir pressure is a well-known value, the pressure the test falls off to can be checked against the known reservoir pressure [46].

6.4 Communication Test

In the proposed method, a communication test and an XLOT are performed simultaneously in the upper perforation set. It can therefore be considered as one test providing multiple data points. The communication test is performed to identify any possible leak paths in the interval between the zones, by evaluating if the fluid injected into one zone leaks into another zone.

A large part of the proposed method revolves around identifying any vertical communication, i.e. leaks in the liner annulus or behind the outermost casing between the perforations. This will identify if an external barrier is sufficient to withstand maximum anticipated pressures and loads. The test will verify if there is annular liner cement present and inform the pressure it can withstand. Figure 6.9 is an example of a possible well configuration during an XLOT/communication test. The well configuration is identical to the configuration during an XLOT because the tests are performed simultaneously. The pressure responses from the lower perforation set (Zone 1) are recorded by a downhole memory pressure gauge set on a retrievable bridge plug. Using a memory pressure gauge does not allow for real-time pressure measurement at surface and to be able to extract the recorded pressure data, the gauge must be retrieved [3]. The pressure response from the upper perforations (Zone 2) is measured at surface in the closed off well by monitoring pressure build-up [46].

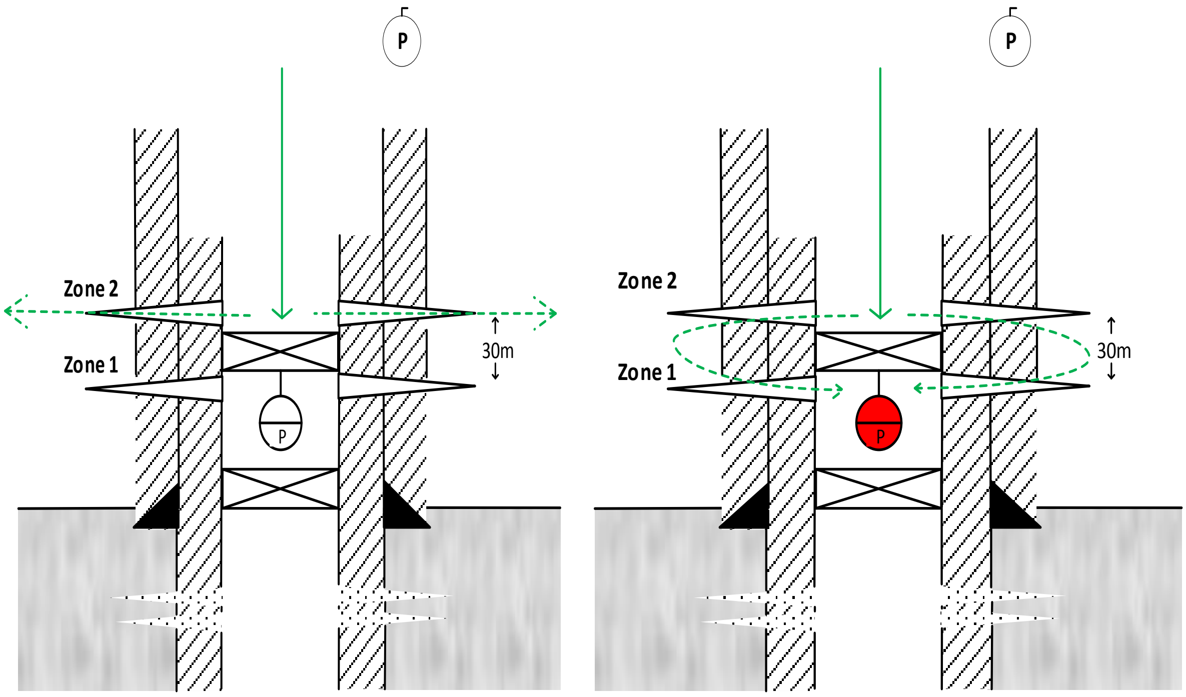


Figure 6.9 a) Successful communication test b) Failed communication test

An internal requirement is that the barrier between the two zones shall be able to withstand maximum future reservoir pressure minus the oil gradient up to the lower tested zone. [3] There should be no pressure response on the downhole pressure gauge if the external barrier has good cement bond as Figure 6.9 a) shows. Any detected pressure response on the gauge will reveal if there is a leak/communication and further verify that there is poor or no annular cement present. This is illustrated by a red pressure gauge in Figure 6.9 b). Because the communication test and XLOT are performed simultaneously, the pressure response on both the downhole gauge and at surface will have the appearance of an XLOT if there is communication between the zones.

If there is no vertical communication, the pressure responses from the upper and lower perforations should be flat and constant for both cycles. The values and behaviour are indicating communication with an induced fracture as intended, and not the annulus. If there is communication there will be an increase in pressure on the deepest downhole gauge. Because the pressure cycles are applied like XLOT, the communication test may be considered as a communication test in XLOT mode. As a result, the communication pressure response will have the appearance of an XLOT graph should there be communication between the perforations. Performing a communication test in XLOT mode will test the formation beyond FBP. The obtained pressure responses will therefore have the same appearance as an XLOT, making it easier to compare with other XLOT curves [26].

Figure 6.10 is a magnified section of the pressure response inside the red circle in Figure 6.11. The red circle indicates when the communication test is run. Because the successful communication tests in the case study have a similar appearance to Figure 6.10 below, it should be elaborated why this curve is accepted as opposed to the theoretical flat expected curve. Point 1 in Figure 6.10 shows that when differential pressure is applied through one of the perforations, an increase in pressure on the downhole gauge followed by a sudden flat plateau can be observed during the first cycle. A pressure response on the downhole gauge will normally signify that there is communication between the perforations, and it must therefore be determined whether this pressure increase is hydraulic or caused by movement of the well or downhole equipment. It is possible to go downhole to check the equipment after communication has been established, to verify the source of the pressure increase. A further investigation into this in the case study, revealed that the pre-set bridge plug below the pressurized perforations experiences a piston effect when pressurized, subsequently moving the bridge plug slightly downwards thus generating a higher pressure. This increased pressure effect may also be induced by a moving packer [26].

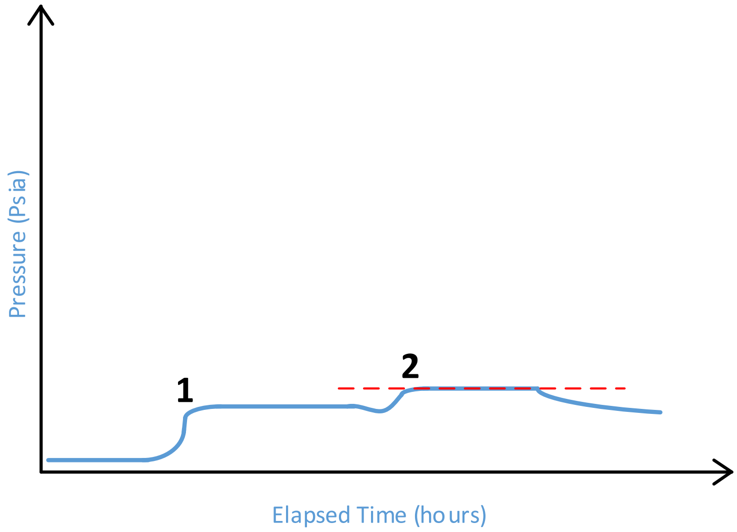


Figure 6.10 Schematic of a successful communication test. The pressure responses are interpreted as moving equipment and not hydraulic communication.

The observed decrease of pressure after the flat plateaus could be caused by tortuosity in the perforations. Tortuosity in this context could be understood as perforations characterized by bends and curves, and not a perfect cone shape as some illustrations may show. Subsequently, the pressure decrease occurs because of increased friction in the tortuous perforations caused by debris in the perforations or collapsed perforations. This is dependent on how the perforations are executed [48]. The decrease in pressure could also be a volume of fluid trapped below the plug leaking off back down to the pore pressure [26].

Point 2 in Figure 6.10 shows that the pressures from the first cycle are repeated in the second cycle. Because it was established that the increased pressure was caused by movement of downhole equipment, it may be concluded that there is no hydraulic communication between the perforations. The pressure response at Point 2 is higher than Point 1 because the applied pressure is slightly higher than at the first point. Resulting from this discovery, Figure 6.10 illustrates the desired result from a communication test [50].

6.4.1 Communication Test Scenarios

The figures below illustrate a successful and a failed result from communication tests. The communication test itself is performed during a limited time interval. To simply this, the test interval is highlighted by a red circle in the figures. Both figures are examples from wells considered in the case study, and a thorough interpretation of these will follow.

Figure 6.11 illustrates a successful communication test. There is no significant pressure increase when applying differential pressure, except the slight increase inside the red circle caused by equipment movement. This figure is an example from Well A in this thesis.

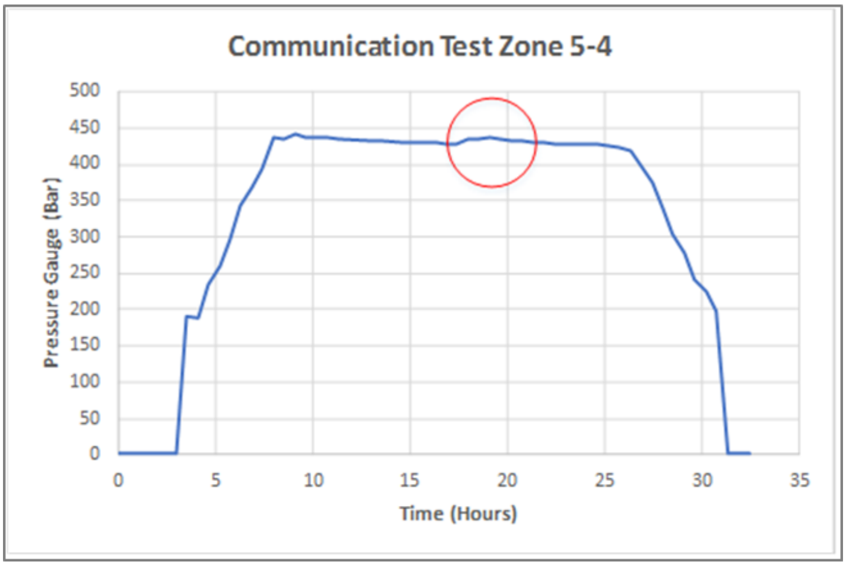


Figure 6.11 Successful Communication Test

Well C provides an example of a failed communication test where hydraulic communication between the liners was confirmed. Communication was established because the pressure data revealed an XLOT graph as shown within the red circle in Figure 6.12. This pressure was measured on the bottom gauge, which shows an increase in pressure because the well is not externally isolated due to poor external cement. Communication may be established by either an increase in pressure response on the gauges or by fluid return in the annulus [46].

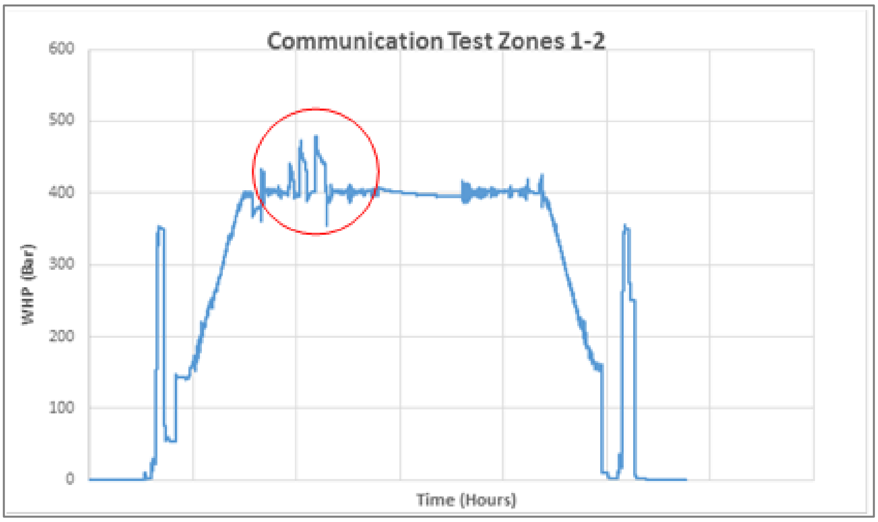


Figure 6.12 Failed Communication Test

6.4.2 Underbalance Induced Shale Influx

A drawdown could be defined as a created pressure difference, typically used for tests with the objective to determine skin, permeability and the distance to reservoir boundaries. Nevertheless, it may be applied for other purposes as well, which was discovered while Aker BP attempted to verify barriers through dual cemented liners during the implementation of the proposed method.

By using CT and water for performing the tests, a differential pressure between the pore pressure and fracture pressure will appear on the surface while perforating the zones, because of the low hydrostatic weight column. This allows for operating with higher surface pressures while the bottom hole pressure is the same as when operating a drill pipe in mud; this is opposed to a drilling rig who operates with zero surface pressure due to the higher weight fluid column in the wellbore. If the pressure differential is e.g. 2000 psi, the XLOT could be started at -2000 psi. This introduces an advantage of the CT because the 2000 psi at surface is the amount of drawdown that can be placed on the formation when the pressure bleeds off to zero. The test described below uses drawdown to create an underbalance differential pressure in attempt to induce shale influx, which can be used as an external barrier [26].

While performing communication tests on the various wells, communication was detected because of fluid in the annulus between the two liners. Communication in the annulus could indicate areas with poor or no annular cement. Instead of concluding that an area is unfit to qualify as an external barrier, a differential pressure was created in attempt to draw out any fluid in the annulus, as well as lower the pressure inside the well to induce shale influx and establish formation as barrier. This is executed by lowering the pressure inside the well while the shale outside the casing is over-pressured because it is isolated. An underbalance is created by lightening the hydrostatic fluid column. The well is displaced to water, and to avoid under-pressure, some pressure must be added to keep the well over-pressured. Nevertheless, the well pressure must be lowered below the pore pressure by creating a differential pressure to induce shale influx. For this reason, the procedure may be called an Underbalance Induced Shale Influx (UISI) [48].

7. Proposed Approach for Barrier Testing and Verification

In order to plug and abandon a well in accordance with regulations, specific requirements must be followed when it comes to barrier characteristics, testing and verification. There are no logging tools on the market able to log the external cement of dual cemented liner wellbore. This introduced a challenge when some of the wells on Valhall needed to be plugged.

The basis for the proposed approach is a communication test as required for proving a logged shale barrier. The team from Aker BP further asked themselves how much of this was possible to do rigless. When rubbing their heads together, the team from Aker BP discussed the following:

- What can be done using already existing intervention tools?
  - We can perforate
  - We can set plugs
  - We can isolate perforations
  - We can pump cement

The team decided to use XLOTs and communication tests to establish and verify barriers to restore the cap rock. The procedure was done by using CT. Not only would this save a considerable amount of money – the procedure was also very safe because there was no need to pull the tubing and both XMT and BOP were therefore rigged up all the time.

The main steps of the proposed method may be summarized to [51]:

- Isolate the reservoir by setting a permanent bridge plug.
- Perforate a minimum of two sets of perforations through the dual cemented liners.
- Perform XLOT through each perforation set to verify external-most barrier to reservoir.
- Perform a communication test in XLOT mode. This is done to:
  - Confirm liner annulus cement
  - Confirm external-most barrier
- Lay cement across perforated interval to establish internal barrier and pressure test to verify it. An internal requirement is a minimum of 50 meters of cement pumped above each perforation set.

The objective of this operation was to restore the cap rock by verifying no leak paths outside the 7 in. liner and between the 7 in. and 5 in. liners by performing XLOTs and communication tests. Figure 7.1 displays the reservoir section after both external and internal barriers have been established and verified by implementing the proposed approach of barrier restoration.

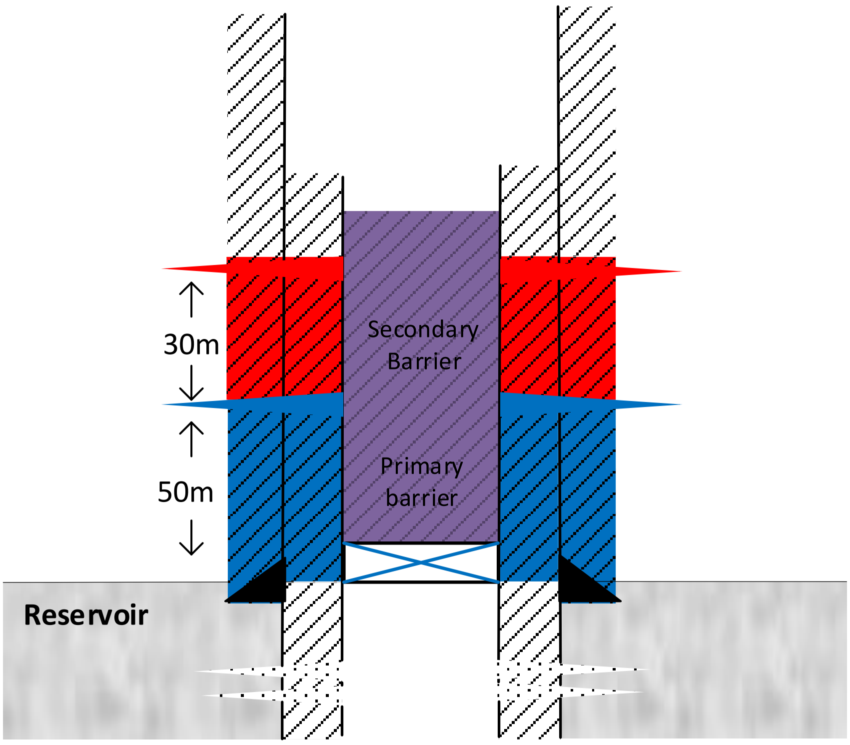


Figure 7.1 Internal and external barriers established and verified

7.1 Operational Sequence

To fully comprehend the scope of the process and mentioned steps, the main steps should be further elaborated. It is assumed that Phase 0: Preparatory work, is executed before this to ensure sufficient wellbore access. The term “Zone” used in this operational sequence refers to a set of perforations shot at one depth, i.e. the lower perforations in Figure 7.2 is considered as Zone 1 and so on. There is a 30 meter interval between each zone based on the communication test interval used when testing a shale barrier identified using logging. Because of different well configurations and conditions, the procedure needed alterations to be successful in every well. This is elaborated in the case study.

The perforations were shot inside the shale cap rock:

- It was shot 6 shots/ft. to cover 360 degrees of the well. 1-2 ft./shot. Minimum two sets of perforations.

- It is important to ensure that the perforation shots are sufficiently strong so that they reach through the dual liners and into the formation. A poor shot would require re-perforation or other remedial actions.

The operational sequence may be summarized to [26]:

1. RIH with CT rigged up with an inflatable permanent bridge plug which is set on top of the reservoir to isolate. The plug must be leak tested as per requirements of NORSOK D-010. POOH.
2. RIH using a tandem TCP gun to reach the deepest depth possible, and to be able to perforate two zones in one run.
   a. Perforation guns are fired a minimum of 50 meters above the reservoir to create the first perforation set (Zone 1).
   b. XLOT is performed through the perforations to ensure open perforations and to check formation strength and integrity. This is also done to check for any hydraulic communication with the reservoir. POOH.
3. Perforate Zone 2 approximately 30 meter above Zone 1. RIH with a bridge plug with a memory pressure gauge. This is set above the first perforation zone to isolate the well internally. POOH.
4. Figure 7.2 illustrates an XLOT in Zone 2. The pump output is measured at the wellhead.
5. A communication test in XLOT mode is performed through the perforations in Zone 2 to check if the well is isolated externally (see Figure 6.9). The bridge plug between the zones ensures internal isolation. The communication test is executed by pumping fluid down the well through the XMT. If there is communication as the red gauge indicates, there is most likely a leak.
   a. Pressure is continuously recorded by a downhole gauge to identify any leaks from Zone 2 through the annular liner cement and into Zone 1. The gauge is built with a timer and will record hydrostatic pressure.
   b. Once the gauge is pulled, pressure can be read off to confirm the communication test that was performed through Zone 2.
6. If all XLOTs provide good results, external barriers are established.
7. If communication is detected from Zone 2 to Zone 1 one may attempt to induce shale influx. If no influx, which is the case for our three wells, a bridge plug is set above Zone 2 before a third zone is created. Then XLOT and communication test are performed in Zone 2 and Zone 3. This is repeated until no communication is established.

8. Equipment inside the well is retrieved and cement is placed downhole using CT to establish internal barrier (See Figure 7.1). The perforations are considered as open hole sections and the cement plug should follow the requirements given in Chapter 3.1.1.5 related to this.
9. Tag and test cement plug. Reservoir is now fully isolated and abandoned, and Phase 1 of P&A is complete. POOH.

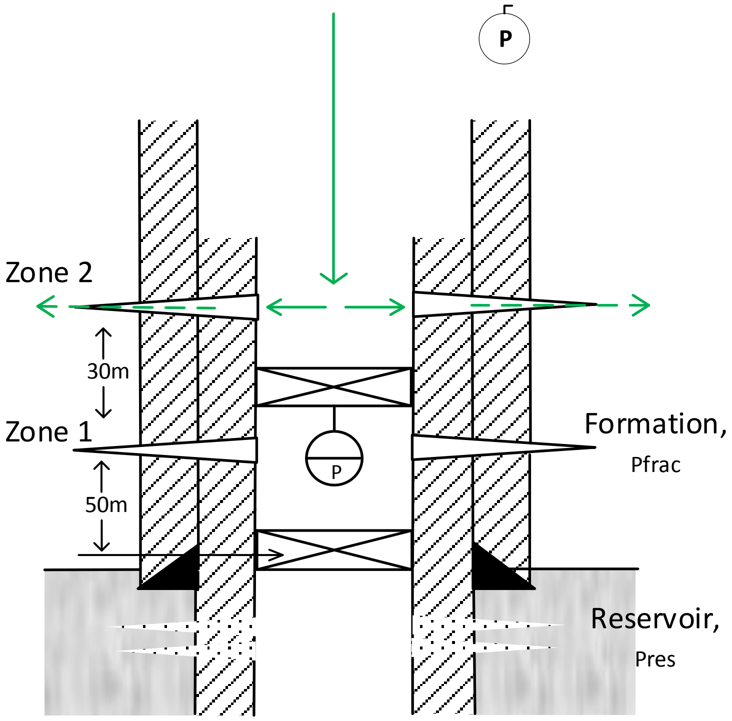


Figure 7.2 Extended Leak-Off Test by pumping through XMT

8. Case study

Well designs and the surrounding geology vary in a great extent, both in characteristics and in complexity. Because of the large variations, it is ambitious to make a general description of a P&A operation. For those reasons, the proposed method of barrier restoration presented in Chapter 7 had to be adjusted and adapted for each of the three wells. This will also be something to consider for future wells.

The following chapter considers the three wells as separate cases, and will present and discuss the various alterations to the P&A method that were implemented. The configuration schematics provided for each well highlight any interval with communication by an orange color. The wells considered in the study are actual wells owned by Aker BP located on Valhall DP. For simplicity of the study they will be referred to as wells A through C. Well data and operation details presented in this thesis were provided by Aker BP and were found in internal well reports and presentations. Additionally, the pressure data was further processed and finally presented in plots in the study. Interpretations of the results have been made to prove that the proposed approach carried out in these wells is sufficient compared to the requirements in NORSOK D-010. It is also suggested to avoid using a CBL in well configurations where two casing strings exist to save time and cost.

8.1 Well A

8.1.1 Well Data

Well A was completed with a heavy wall 5 1/2 in. liner set inside a non-heavy wall 7 5/8 in. liner. Owing to poor centralization, cement losses and a highly deviated wellbore, the annular cement was expected to be poor. Because a top squeeze was performed, a good cement section was expected at the top of the interval. Data for Well A is presented in Table 8.1.

Well A	
Inner liner size	5 1/2 in., 45,5 ppf
Outer liner size	7 5/8 in., 33,7 ppf
Liner Annulus Cement	
Centralization	None
Hole angle at shoe	90,2 degrees
Rotation of pipe	No – stuck liner
Losses	30%
Top Squeeze	Yes
Expected Annular Cement	Bad

Table 8.1 Well A: Data

8.1.2 Operational Sequence

Because the first three zones in Well A failed on the communication test, it was chosen to only provide figures illustrating the zones which fulfilled the barrier requirements given in NORSOK D-010. Well configurations and corresponding plots are provided in Figures 8.1 through 8.7.

The operational sequence of Well A is presented as follows:

- RIH and set a bridge plug to isolate reservoir. Tagged and tested plug. Perforated the first zone 50 meters above reservoir. Performed an XLOT.
- Set a bridge plug with memory pressure gauge above Zone 1.

- RIH with tandem TCP guns. Because of deformations of the wellbore it was not possible for the guns to pass these restrictions. POOH.
- RIH and perforated Zone 2. Performed an XLOT and a communication test. Communication test between Zone 1 and 2 failed. Set a bridge plug above Zone 2.
- RIH and perforated Zone 3. Performed an XLOT.
- Performed a communication test between Zone 2 and 3 with an IJSP. Difficult to get a clear test because the packer requires constant pumping to stay inflated. After further analysis and evaluation of the test at the end of the job, a good communication test was confirmed. Nevertheless, during the operation it was assumed to be failed.
- Performed communication test with an IRPP – failed communication test. Cement was pumped above IRPP to isolate Zone 3.
- Because communication was detected in zones 1-3, a run was made to perforate Zone 4 and 5 with a tandem TCP gun. Performed an XLOT in Zone 4. See Figure 8.1 a).
- Performed a communication test with an IRPP which failed because of incorrect pinning.
- Set a retrievable bridge plug, performed an XLOT in Zone 5 and further confirmed no communication between Zone 4 and 5. See Figure 8.1 b)
- Perforated Zone 6. XLOT.
- Set inflatable bridge plug – communication detected.
- Re-ran bridge plug and confirmed communication between Zone 5 and 6. See Figure 8.2.
- Equipment inside the well was retrieved and cement was pumped downhole to establish internal barriers. See Figure 8.3.
- Tagged and tested cement plug. Reservoir was now fully isolated and abandoned.

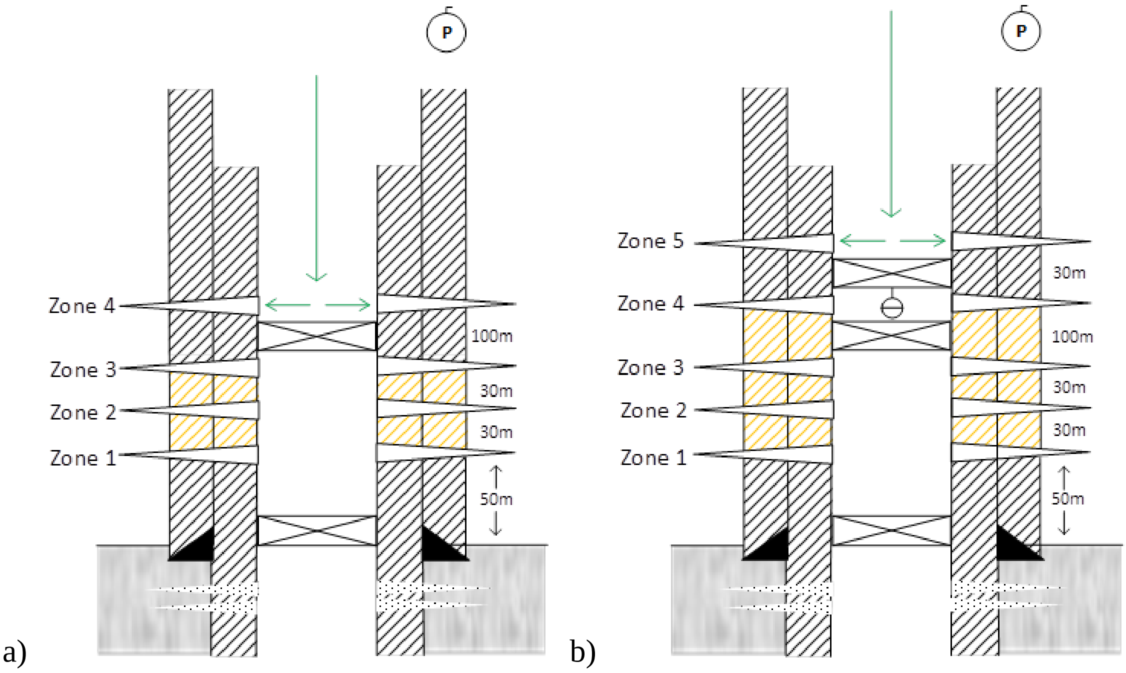


Figure 8.1 a) XLOT Zone in 4 b) XLOT in Zone 5 and Communication test between Zone 5 and 4

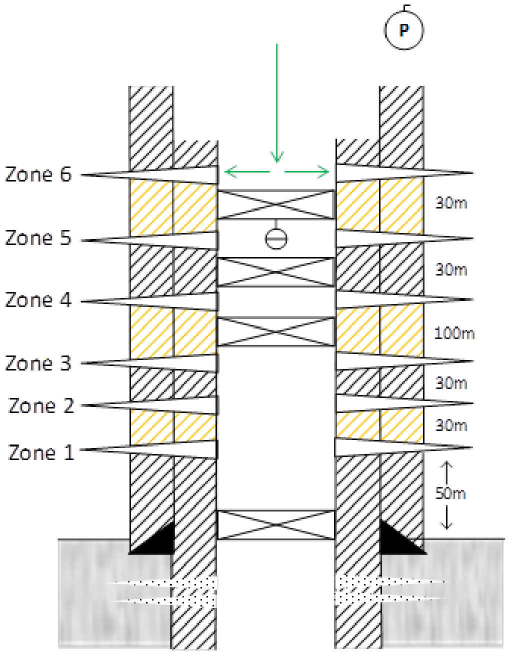


Figure 8.2 XLOT in Zone 6 and Communication test between Zone 6 and 5

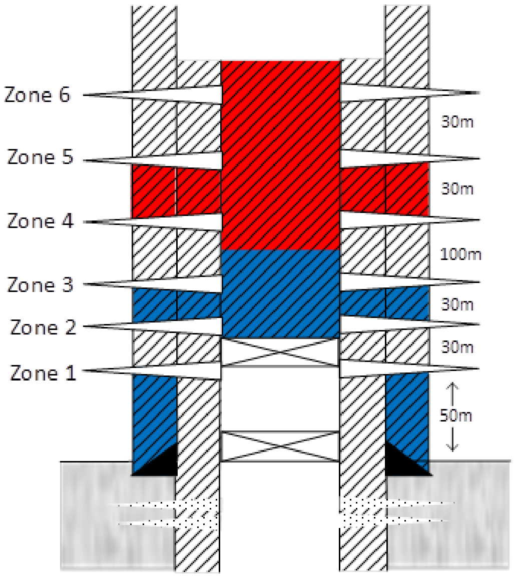


Figure 8.3 External and internal barriers established in Well A

8.1.3 Results

The XLOT in Zone 1 leaked off to fracture pressure, and as mentioned in Chapter 6.3, this would indicate no hydraulic communication to the reservoir. This confirmed the first 50 meter external barrier. Nevertheless, because no cement was pumped internally in this interval, no cross-sectional barrier was established. It should be mentioned that the communication test between Zone 3 and 2 was primarily assumed to be a failed test. After further analysis of the results when the job was finished, it was however considered to be successful. Nevertheless, because the three first zones failed the communication test primarily, this section only studies pressure data from zones 4 through 6.

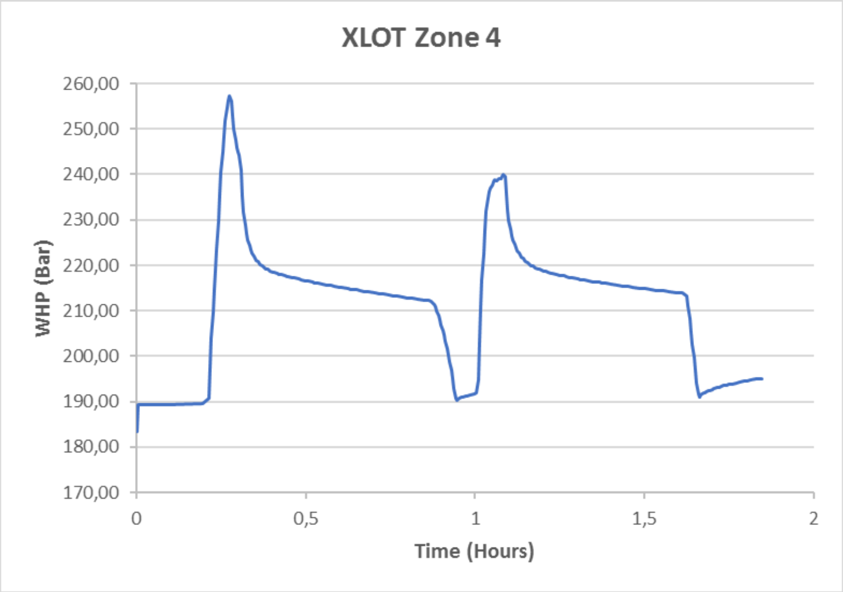


Figure 8.4 XLOT in Zone 4

Figure 8.4 presents pressure data from an XLOT performed through Zone 4 in Well A. The pressure response measured at surface show expected and repeatable values, thus confirming the formation strength at Zone 4. Both pump cycles repeat the same linear behaviour which indicates that the created fracture closes between every pump cycles. The highest peak in the first cycle is the FBP, while the highest peak in the second cycle is FRP. The FBP is higher than the FRP because the fracture requires less pressure to open a second time compared to the first. Between each cycle there is a repeated fall off that corresponds to the S_{Hmin} at that particular depth, and finally a bleed-off to start pressure.

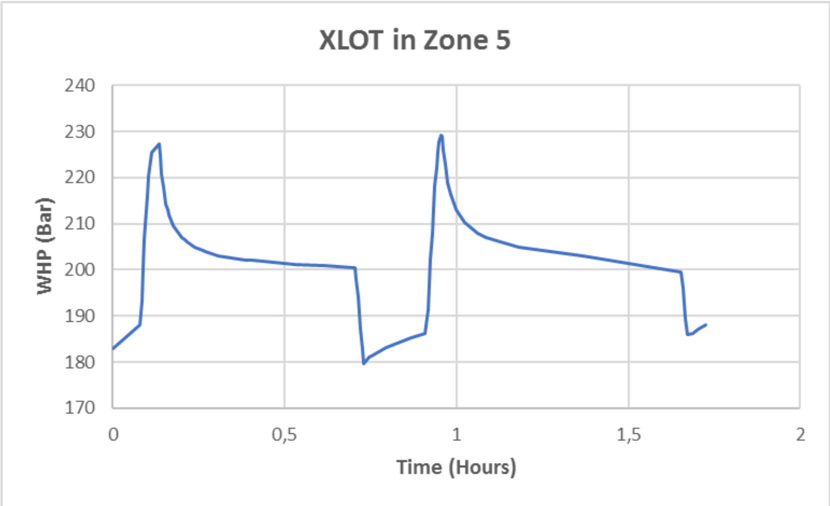


Figure 8.5 XLOT in Zone 5

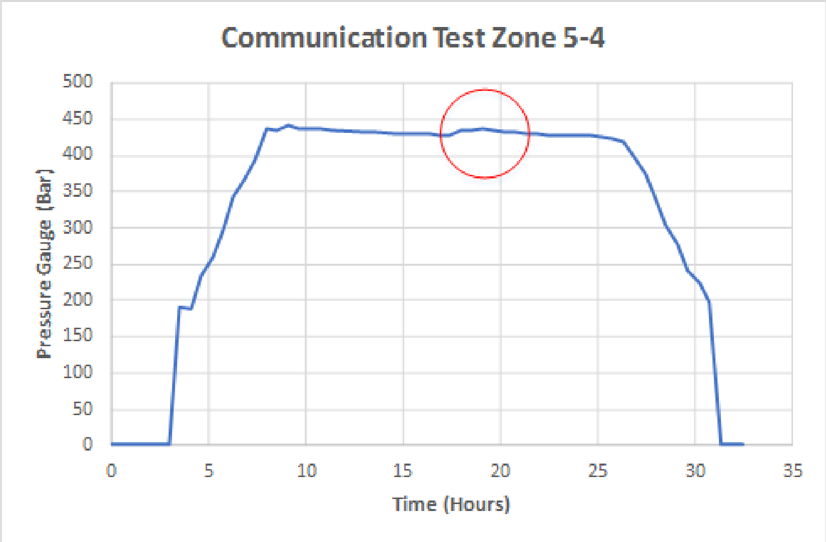


Figure 8.6 Communication Test Between Zone 5 and 4

After perforating Zone 5, both an XLOT and communication test was performed. The XLOT in Figure 8.5 display values and behaviour that confirms open perforations. It also indicates communication with the formation because the pressure leaks off and confirms the expected formation strength. Similar to Zone 4, the pressures in Figure 8.5 are repeated for each cycle. This confirms that there is no hydraulic communication to the reservoir.

The curve inside the red circle in Figure 8.6 is the communication test which is measured at a downhole pressure memory gauge in Zone 4. The pressure data from the gauge shows no significant pressure response and the test is thus considered to be successful.

A thorough evaluation of the pressure data inside the red circle would reveal a slight pressure increase in two cycles. As mentioned in Chapter 6.4 this is owing to movement of downhole equipment, more specifically the packer, and not hydraulic communication between the zones.

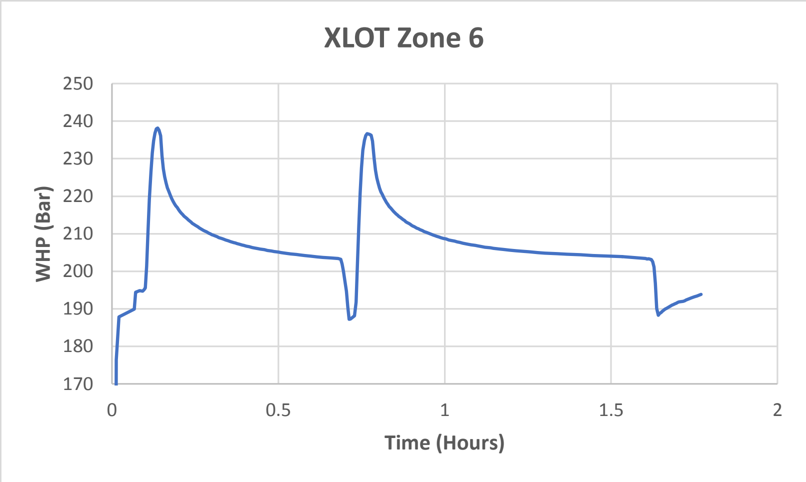


Figure 8.7 XLOT in Zone 6

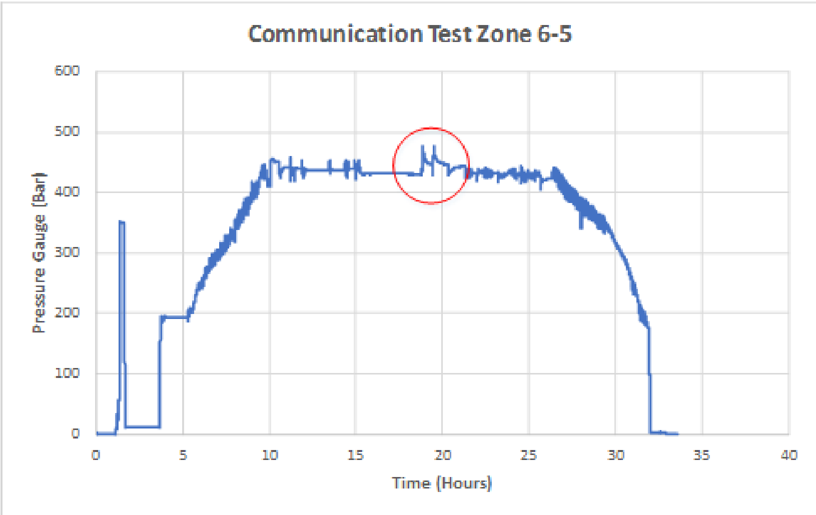


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Figure 8.8 Communication Test Zone 6-5

The XLOT performed in Zone 6 provides the same answer as the XLOTs in Zone 4 and 5. The repeated values in Figure 8.7 indicates that the pressure leaks off and confirms the expected formation strength. It is therefore communication with the fracture and not the reservoir or other permeable formations. Both pump cycles repeat the same closure pressure, indicating that the fracture closes between each cycle.

The communication test in Figure 8.8 was performed by pumping fluid into Zone 6 to evaluate the annular cement between Zone 6 and 5. As can be seen in the figure, there is significant pressure response during the period of injecting fluid, which indicates full hydraulic communication between the zones. This is clear from the obvious XLOT characterized appearance of the pressure curve, that is recorded on the downhole memory pressure gauge.

The detected communication is expected to be located in the annuli between the two casings resulting from poor or no annular cement. This expectation is based on a long track record of shale induced collapse and shale barriers on the Valhall field in these formations.

Table 8.2 presents a summary of the tests performed in Well A during barrier restoration of the cap rock. Even though communication was detected in the annuli between Zone 6 and 5, a sufficient length of acceptable external cement barrier was identified in the 217 meter MD perforated interval.

XLOT and Communication Tests Summary	
Length between Zone 1 and Zone 6	217 meter MD
XLOT in Zone 1	- Showed expected values regarding formation strength at the perforated depth. - Repeated values indicates sealing material outside the casing and thus no hydraulic communication to the reservoir or permeable formations in the overburden.
Communication Tests	Zone 1 and 2 – failed Zone 2 and 3 – OK Zone 3 and 4 – failed Zone 4 and 5 – OK Zone 5 and 6 – failed

Table 8.2 Well A: Summary of tests

8.1.4 Interpretation and Discussion

By evaluating the cement job, it was expected good annular cement at the top of the cemented interval and poor cement at the bottom. Results from several communication tests did nevertheless not verify any of these assumptions as seen in Table 8.2. Although there was expected to be communication between Zone 3 and 2, a further evaluation of data and equipment revealed that the IJSP caused misinterpretation of the data at first. To stay inflated, the IJSP requires constant pumping. This causes difficulties interpreting the pressure response because formation breakdown is reached while inflating the plug, and one must continue pumping to preserve the sealing properties of the plug.

A second attempt to verify good annular cement between Zone 3 and 2 was performed by setting an IRPP. The plug provides adequate data, however, in case of a leak and further an increase in pressure response on the downhole gauge, it is uncertain if this is resulting from movement of the plug or an actual leak in the well. The failed communication test using this equipment was a learning process for the team to consider for further wells.

NORSOK D-010 requires a minimum of 50 meters MD of external WBE, with formation integrity at the base of the interval. This barrier was established by performing an XLOT in Zone 1, however, no cement was pumped internally so no cross-sectional barrier was established. Further, NORSOK D-010 specifies a requirement of 30 meters MD of cement length verified by logs. In the proposed approach no logs were run, however, instead pressure tests were conducted. A log only identifies bonding and the length of the bond, and provides no information about the sealing ability, quality or extent of a barrier. A communication test will provide information about how strong a barrier is, and by performing XLOTs, the barrier is tested to the maximum pressure it will be exposed to for eternity. Testing up to fracture initiation as presented in Chapter 6.3, with a depleted reservoir is the highest differential pressure possible.

From performing numerous communications tests, a total of 60 meters of acceptable verified external barrier was identified, fulfilling the requirement of 2 x 30 meters given in NORSOK D-010. In the end, cement was placed internally on a mechanical foundation. The internal cement plug is characterized as an open hole plug, and therefore a 100 meter cement with minimum 50 meter above any source of inflow was set on a mechanical foundation.

8.2 Well B

8.2.1 Well Data

Well B was completed with a heavy wall 5 1/2 in. liner inside a non-heavy wall 7 in. liner. The casings are not centralized and the well is highly deviated by 93 degrees. During cementing of the casings, Aker BP experienced no cement losses and did not need to perform a top squeeze. The annular cement was therefore expected to be good, and because there was no top squeeze or losses, the good cement section was expected to be at the bottom of the interval. Table 8.3 presents the well data for Well B.

Well B	
Inner liner size	5 1/2 in., 45,5 ppf
Outer liner size	7 in., 32 ppf
Liner Annulus Cement	
Centralization	None
Hole angle at shoe	93 degrees
Rotation of pipe	Yes
Losses	None
Top Squeeze	No
Expected Annular Cement	Good

Table 8.3 Well B: Data

8.2.2 Operational Sequence

Similar to Well A, well configurations and corresponding plots for Well B are provided in Figures 8.8 through 8.14. Because the first four zones failed the communication test, only the zones which fulfilled the barrier requirements given in NORSOK D-010 are illustrated.

The performed steps are as follows:

- Set bridge plug to isolate reservoir. Tagged and tested plug. Perforated the first perforation set 30 meters above the reservoir, and performed an XLOT to check for communication with the reservoir. A bridge plug with a pressure gauge was then set above Zone 1.

- RIH with a tandem TCP and perforated Zone 2. Performed an XLOT on Zone 2, attempted to create an UISI and tag on Zone 2. Communication test between Zone 1 and 2 – failed. Perforated Zone 3.
- Set a plug between Zone 2 and 3. Performed an XLOT test on Zone 3 and a communication test between Zone 2 and 3.
- Tagged and tested plug between Zone 2 and 3. Plug was OK.
- Retrieved memory pressure gauges and read data. Communication to reservoir was detected.
- Set plug above Zone 3 and perforated Zone 4 above plug. XLOT.
- Pulled plug with gauge – better, but communication was still detected.
- Set plug above Zone 4 and perforated Zone 5 above plug. XLOT. See Figure 8.9 a).
- Pulled plug with gauge – better, but communication was still detected.
- Set plug above Zone 5 and perforated Zone 6 above plug. XLOT. See Figure 8.9 b).
- Pulled plug with gauge – no communication. See Figure 8.10.
- Set plug above Zone 6 and perforated Zone 7 above plug. XLOT.
- Pulled plug with gauge – no communication. OK.
- Equipment inside the well was retrieved and cement was pumped downhole to establish internal barrier. See Figure 8.11.
- Tagged and tested cement plug. Reservoir was now fully isolated and abandoned.

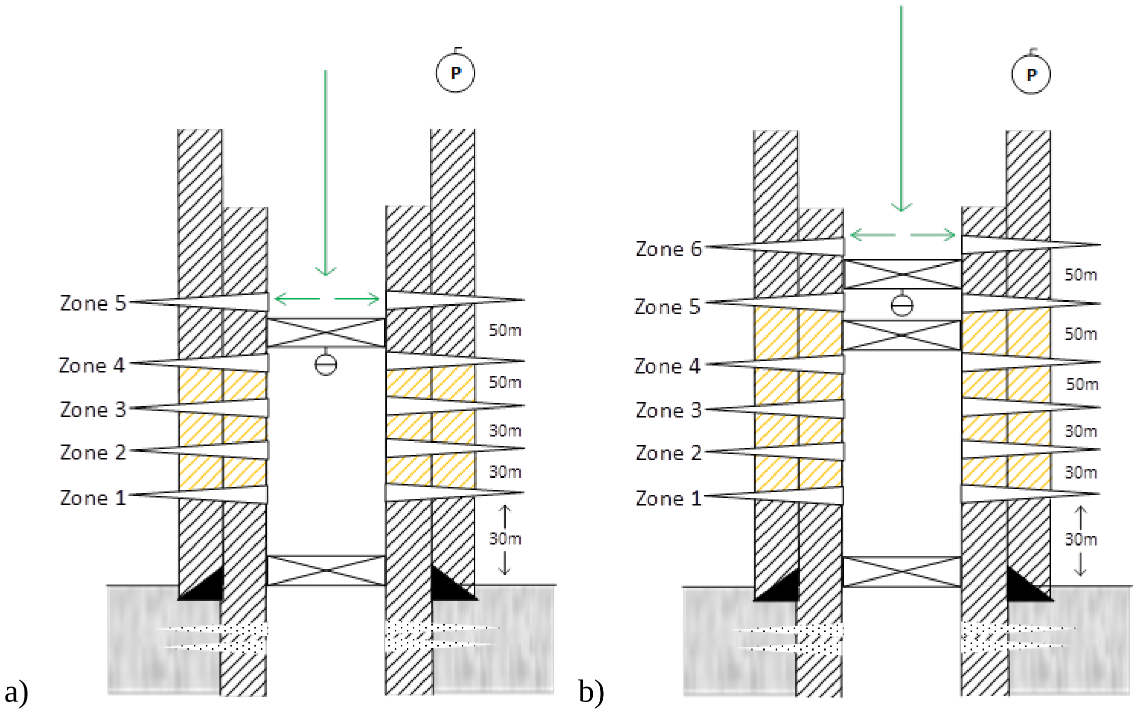

Figure 8.9 a) XLOT in Zone 5 b) XLOT in Zone 6 and Communication test between Zone 6 and 5

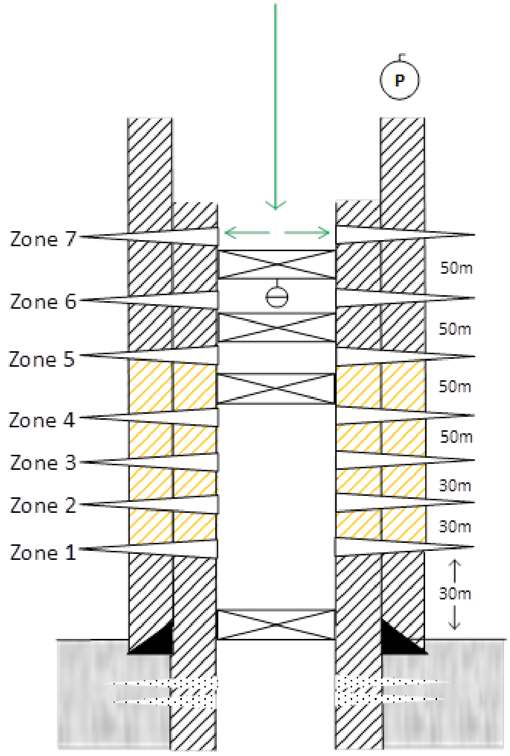

Figure 8.10 XLOT in Zone 7 and Communication test between Zone 7-6

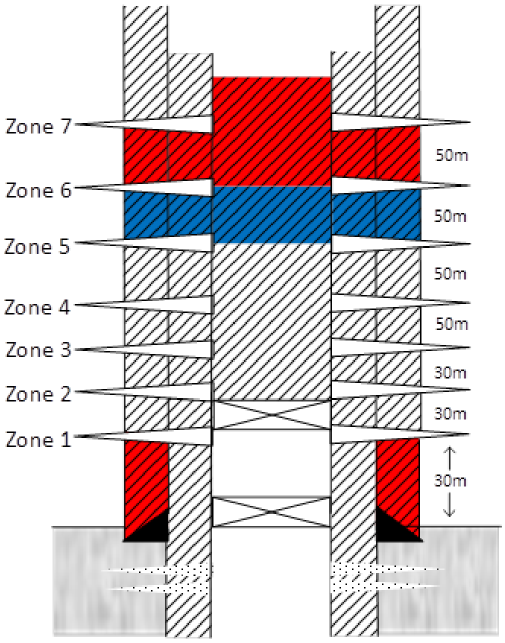

Figure 8.11 Internal and external barriers in Well B

8.2.3 Results

An XLOT performed in Zone 1 confirmed the first 30 meter external barrier as there was no communication down to the reservoir. Several communication tests subsequently revealed hydraulic communication in the annuli in zones 1 through 5, thus to obtain a satisfying barrier interval, additional zones had to be perforated. Regardless of perforating in the shale cap rock, it was discovered permeability in some of the perforated zones. It was therefore attempted to induce shale influx by creating a pressure differential. Resulting from presence of a permeable formation or cement, some of the pressures levelled off to pore pressure.

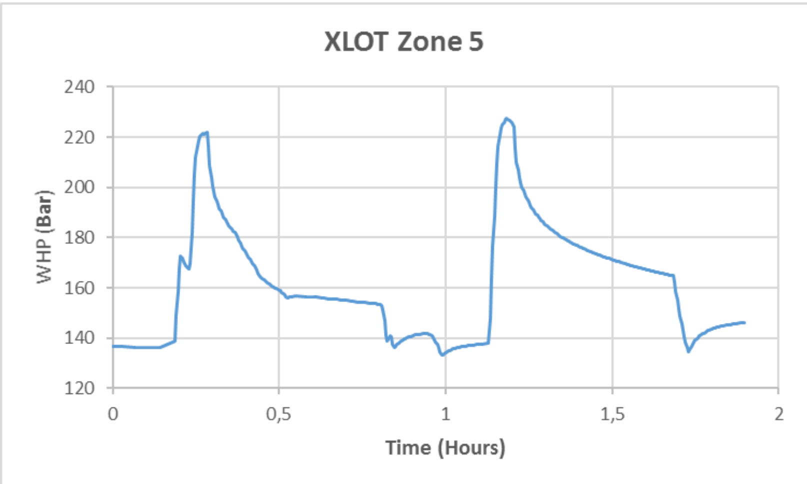

Figure 8.12 XLOT in Zone 5

After Zone 5 was perforated 30 meters above Zone 4, an XLOT was performed. Figure 8.12 displays the surface pressure response after fluid was injected through the perforations. The peak pressure corresponds to expected formation strength in the area and is repeated in the second cycle. The pressure falls off to expected shale closure pressure, $S_{Hmin,}$ at the particular depth indicating communication with the formation and leak off to a fracture. It should be pointed out that the first cycle may have ended prematurely, meaning it was ended before a fracture had initiated. The first cycle will therefore not reach FBP or FCP. These pressures are nevertheless found in the second cycle.

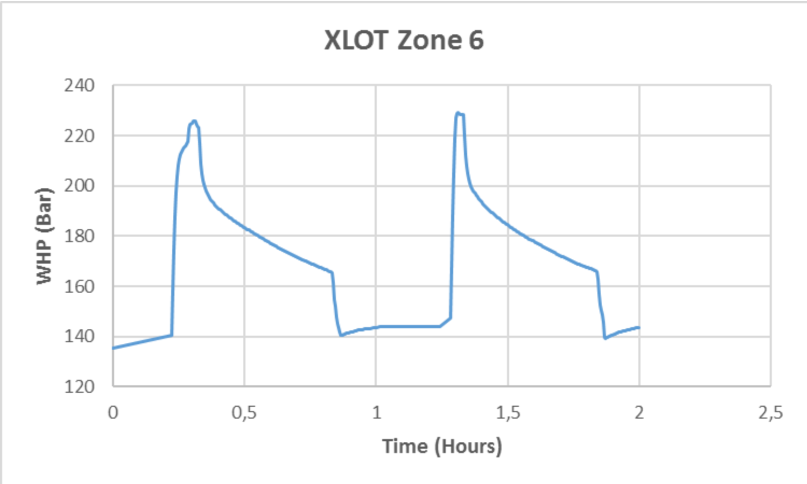

Figure 8.13 XLOT in Zone 6

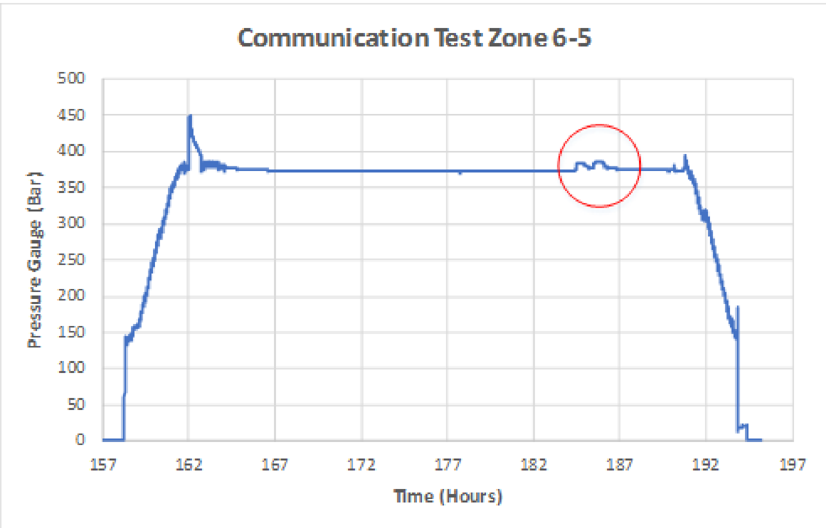

Figure 8.14 Communication Test Zone 6-5

As opposed to Zone 5, it was in XLOT in Zone 6 identified both FBP and FCP which confirmed open perforations, and formation strength and integrity, as seen in Figure 8.13. The communication test performed between Zone 6 and 5 shows a pressure response on the downhole gauge in Figure 8.14. Nevertheless, because the response was not equivalent to the pressure response of the XLOT in Zone 6, the response was denoted as equipment movement and not hydraulic communication.

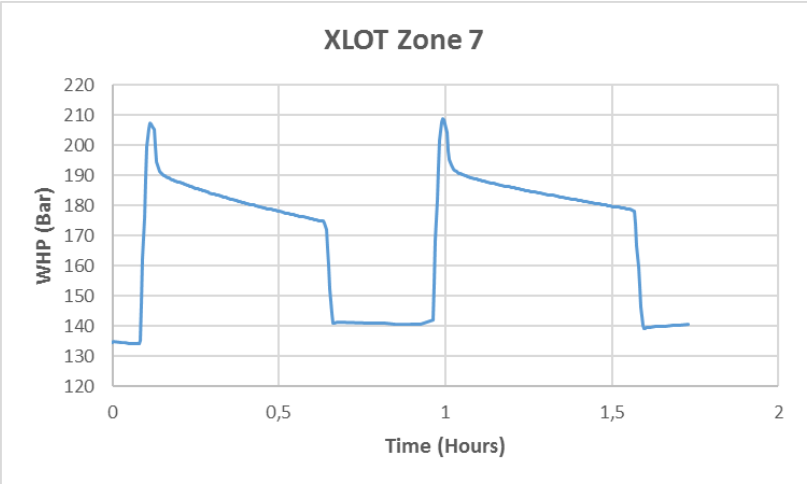

Figure 8.15 XLOT in Zone 7

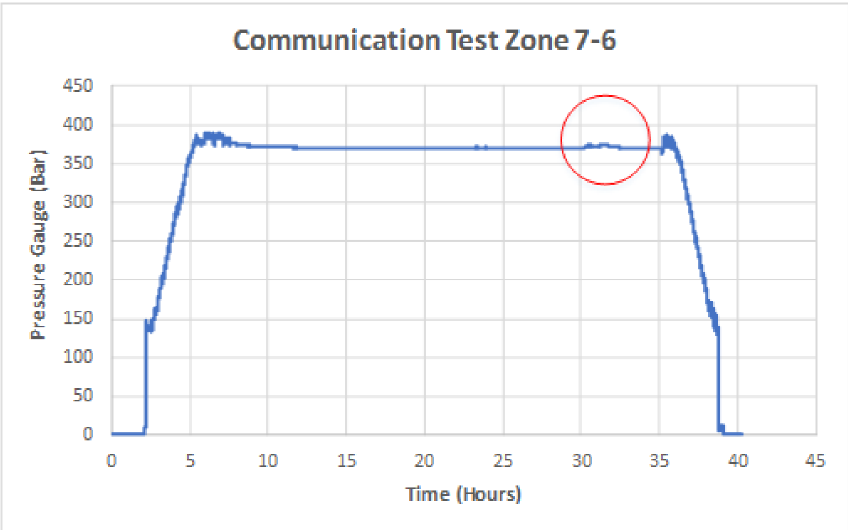

Figure 8.16 Communication Test Zone 7-6

The pressure responses during the XLOT of Zone 7 presented in Figure 8.15, were as expected. The fall off pressure fell to expected pore pressure. This is resulting from presence of either a permeable shale formation or cement with fractures, high porosity or channels.

Figure 8.16 revealed no hydraulic communication in the annuli between the zones, and the pressure increase was again interpreted as movement of downhole equipment.

A summary of the results is presented in Table 8.4.

XLOT and Communication Tests Summary	
Length between Zone 1 and Zone 7	289 meter MD
XLOT in Zone 1	- FBP corresponds to expected formation strength -Repeated values indicates sealing material outside the casing and thus no hydraulic communication to the reservoir or permeable formations in the overburden.
Communication Tests	Zone 1 and 2 – failed Zone 2 and 3 – failed Zone 3 and 4 – failed Zone 4 and 5 – failed Zone 5 and 6 – OK Zone 6 and 7 – OK

Table 8.4 Well B: Summary of tests

8.2.4 Interpretation and Discussion

Despite that the annular cement was expected to be good at the bottom of the interval, several communication tests revealed that the good cement was located at the top of the interval as seen in Table 8.4. The communication tests in the lower five zones revealed hydraulic communication indicating poor or no annular cement. The XLOT in Zone 1 establishes the first external barrier of 30 meters above the reservoir which fulfils the requirements of NORSOK D-010, however, no internal cement was placed in this interval and therefore no cross-sectional barrier was established. Because there was no communication between the upper four zones, an additional 100 meter barrier could be established. Finally, cement was pumped into the well to establish internal barriers as seen in Figure 8.11.

8.3 Well C

8.3.1 Well Data

Well C was completed with a 5 in. liner inside a 9 5/8 in. liner. None of these are heavy wall liners. The casings are partially centralized and the well is deviated by 76 degrees. During cementing of the casings, Aker BP experienced no cement losses and no top squeeze was needed. It was possible to rotate the pipe during operations. The annular cement was therefore expected to be good, and because there was no top squeeze or losses, the good annular cement was expected to be at the bottom of the interval.

Well C	
Inner liner size	5 in., 18 ppf
Outer liner size	9 5/8 in., 53.5 ppf
Liner Annulus Cement	
Centralization	Partial
Hole angle at shoe	76 degrees
Rotation of pipe	Yes
Losses	None
Top Squeeze	No
Expected Annular Cement	Good

Table 8.5 Well C: Data

8.3.2 Operational Sequence

Instead of perforating a zone every 30 meters like wells A and B, it was chosen a longer interval of 114 meters between the zones for Well C.

The operational sequence for Well C may be summarized to:

- Set bridge plug to isolate reservoir. Tagged and tested plug.

- RIH with a tandem TCP and perforated two zones in one run. The lower gun assembly was triggered by pressure cycling of the wellbore to perforate Zone 1, 50 meters above the reservoir. Performed an XLOT on Zone 1. See Figure 8.17 a).
- The upper assembly of the TCP was triggered by flow cycling through the CT. Zone 2 was then perforated 114 meters above Zone 1. A bridge plug with a pressure gauge was further set above Zone 1.
- Performed an XLOT in Zone 2 and a communication test in the interval between Zone 2 and 1. Communication test failed. See Figure 8.17 b).
- Equipment inside the well was retrieved and cement was pumped downhole to establish internal barrier. See Figure 8.18. Drilling crew set a secondary barrier at a later stage because the communication test between zones 2 and 1 failed. This is not illustrated in the figure.
- Tagged and tested cement plug. Reservoir was now fully isolated and abandoned.

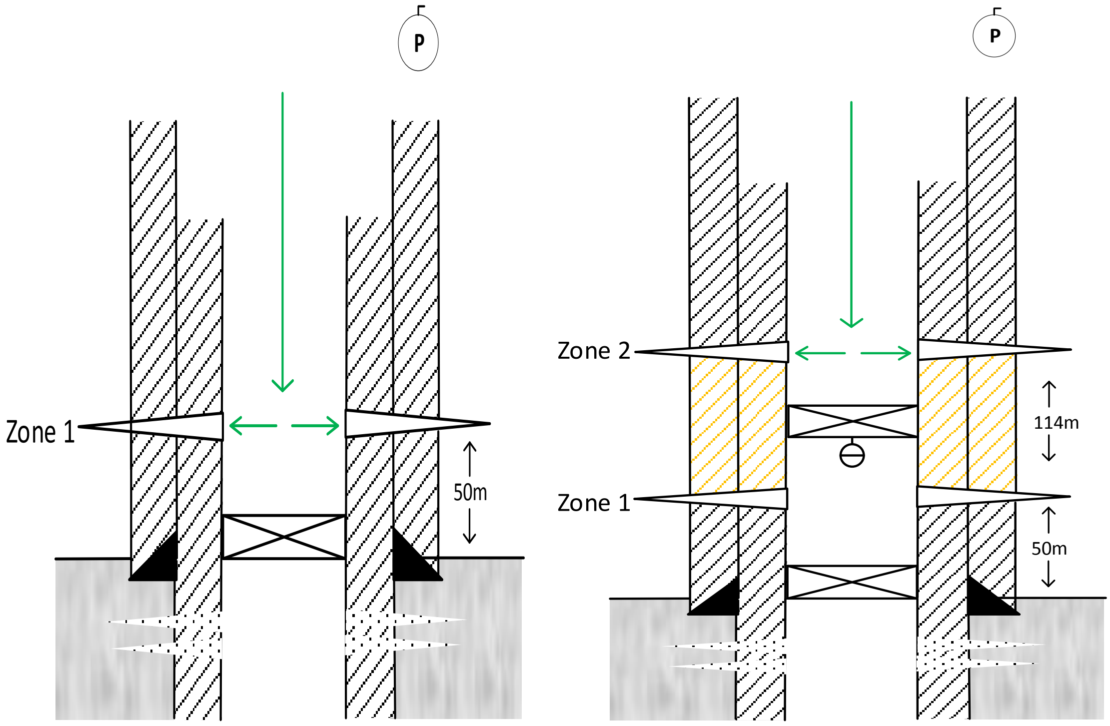

Figure 8.17 a) XLOT in Zone 1 b) XLOT in Zone 2 and Communication test between Zone 2 and 1

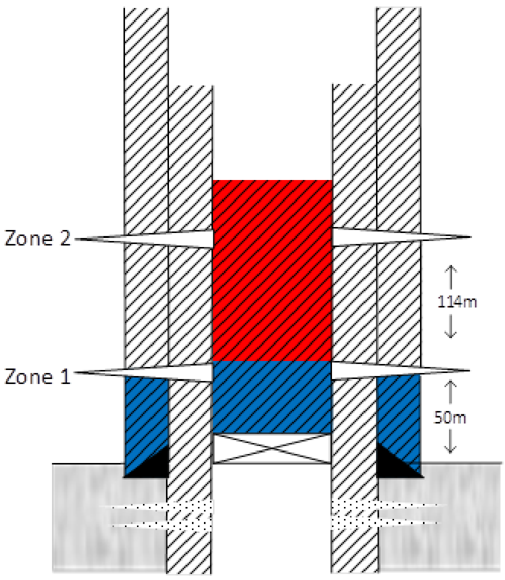

Figure 8.18 Internal and external barriers in Well C

8.3.3 Results

By comparing Figure 8.19 and Figure 8.20, both XLOTs show expected values for formation strength and it is confirmed that there is no communication with the reservoir. This establishes the 50 meter barrier down to the reservoir because of the results achieved during an XLOT in Zone 1. After pulling the downhole gauge and interpreting Figure 8.21, it is evident that there is communication between the two perforations. This confirms that there is poor cement in the annulus, however, it is still uncertain how much of the cemented length consists of poor or no cement.

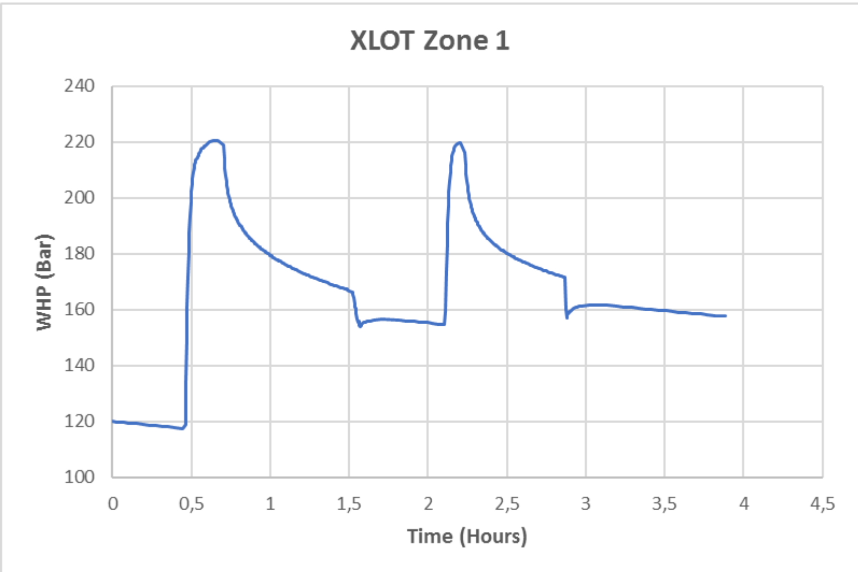

Figure 8.19 XLOT in Zone 1

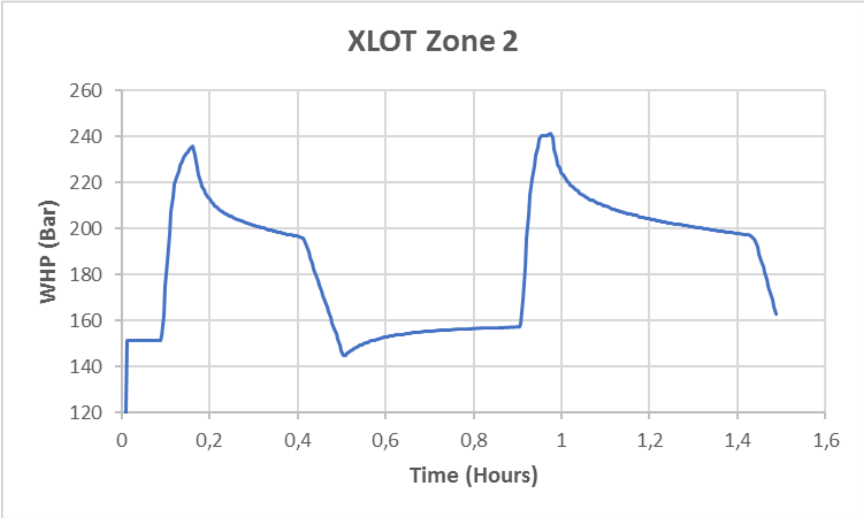

Figure 8.20 XLOT in Zone 2

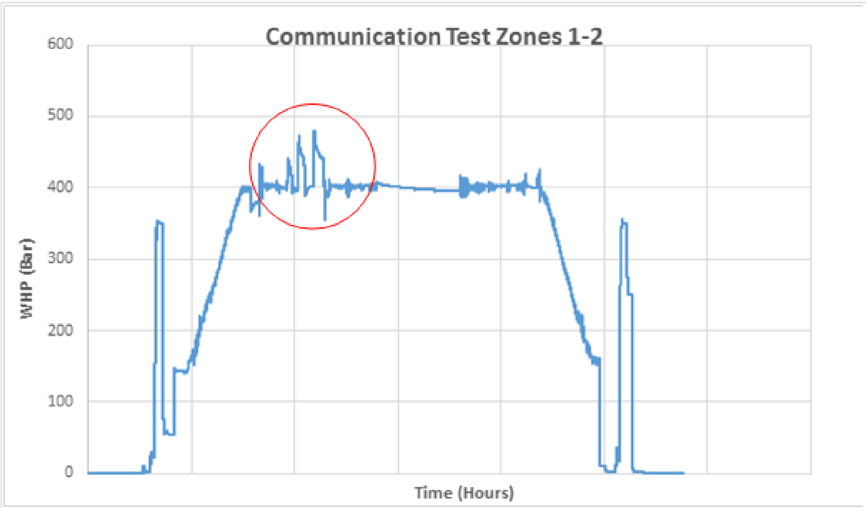

Figure 8.21 Communication Test in Zones 2-1

Table 8.6 summarizes the results from the performed tests.

XLOT and Communication Tests Summary	
Length between lowermost and uppermost perforation	114 meter MD
XLOT in Zone 1	- The XLOT showed expected values regarding formation strength at the perforated depth. - It is concluded that there are sealing material outside the casing and no hydraulic communication to the reservoir or permeable formations in the overburden from this perf.
Communication Test	Failed

Table 8.6 Well C: Summary of tests

8.3.4 Interpretation and Discussion

Results from the first two wells showed that although the cement was expected to be good in certain sections, this was not always the case. Subsequently, the team had to “chase barriers” by perforating several zones upwards. By choosing a longer interval for Well C, the team would obtain either a successful or a failed communication test by performing one test across the 114 meters instead of perforating e.g. three zones and acquire an identical result. This decision saved a large amount of time, money and runs. Additionally, perforating and performing pressure cycles increases the risk of damaging the cement barriers that are in place. The risk is high, and therefore precautions are taken when pressure testing a cemented casing to reduce the risk of damaging the cement job due to expansion of the casing. Testing across a longer interval leaves the cement undisturbed and prevents the number of leak paths occurring from numerous perforations [46].

No cement losses resulted in expectations of good annular cement at the bottom of the cemented interval. This was not confirmed. Through performing an XLOT in Zone 1, the lowermost external barrier to the reservoir of 50 meters was established. Cement was pumped internally for this section and therefore a cross-sectional barrier was established. The following XLOT in Zone 2 confirmed the formation strength and integrity. Both XLOTs match the pore pressure and fracture pressure for the specific depths, and thereby confirm expected pressures.

Shale is a highly impermeable rock and because the perforations are shot in the shale cap rock, the pressure should not level off to pore pressure.

It was later discussed internally that the pressure levelled off to pore pressure because of fluid in the cemented annulus. Fluid may be present in the cement because of channels, micro annuli or a porous cement section, and may further provide a pressure similar to pore pressure [49].

A communication test revealed hydraulic communication between the zones. This was expected to result from a micro annulus between the cemented liners caused by shale collapse. As a result, there is only identified a lowermost external barrier of 50 meters in Well C. To meet the requirements given in NORSOK D-010, it was decided that the drilling crew would set a barrier higher up in the well. This was considered to be sufficient.

8.4 Case Study Conclusion

From reviewing the case study, the following conclusions can be made:

- External formation and cement integrity and strengths were confirmed in every well.
- There is an uncertainty in the actual barrier length, however, the formation is tested to maximum differential pressure and repeats and confirms pressures in every XLOT at expected values.
- Good liner cement was found in three diverse well configurations and cement qualities.
- Three different wells, three different approaches, one result. By implementing learnings from the various wells, it was quickly established which equipment provided desired results and which did not. The results from the case study shows a track record of success.
- Intervals of good cement bond are difficult to anticipate. This became evident when intervals of expected good cement turned out to be intervals of poor cement regardless of what the old cement data indicated.
- The deeper a barrier is set, the better functionality it has because the pressure difference across the barrier is less. By perforating and testing as close to the reservoir as possible to identify intervals of good cement, the barrier position ensuring best functionality is obtained. These intervals can be added together until required barrier length is gained.
- The third well was perforated using a three times larger interval between the zones compared to the first two wells. It was discovered possible cost savings related to this

because it reduced number of trips and that it would provide the same result regardless of selected interval length.

- The method is considered to be sufficient to test and verify hydraulic sealing intervals.

9. Discussion – Justification of Method

Based on the results from the studied tests, it can be concluded that the proposed method provides results equivalent or better than results from the conventional CBL. The proposed method introduces highly robust test procedures which would clearly indicate whenever there is communication. If not able to log, perhaps the proposed approach could be a better solution for whenever dual liners are present. Nevertheless, the possibility of wrong interpretations of the test results should be kept in mind, considering the few executions of the method made up to this date. Parts of the following discussion are based on conversations with the Aker BP teams. This is marked by stating the source.

Performing XLOTs using water as injection fluid, verified open perforations and sufficient formation strength and integrity. Water is less dense and thinner compared to e.g. mud, and can therefore access all possible holes and paths in the formation or cement. Any leak path down to the reservoir caused by bad cement jobs, fractures or micro-annuli, would thereby quickly be identified, and the test can therefore be considered very robust. Water also allowed for an underbalance in the well, which is an advantage because it minimize the potential of formation damage and opens for shale influx.

Without the CBL, there is an uncertainty regarding contact length and variation of the cement bond because the XLOT only tests the sealing capacity of the bond. By testing sufficiently short intervals of e.g. 30-115 meters, the test results would indicate whether there is a sealing barrier or not, and thereby indicate the length of the cement bond should there be a barrier. Because it was discovered communication in some of the intervals and no sufficient barrier elements could be established, the team had to "chase barriers" by perforating zones upwards until the barrier elements could be established. This shows that a contingency plan exist should some of the zones fail. Is 30 meters sufficient for the tests or should the tested intervals be shorter? There are no requirements regarding this, and the answer is yet to be found.

According to NORSOK D-010, there is a requirement of a minimum of 50 meter internal barrier downhole set on a mechanical foundation. Owing to packers, other downhole equipment or deformed wells, it is not always possible to set this internal plug as close to the reservoir as it should, namely at critical P&A depth. Blindly following these requirements could therefore potentially lead to the plug being set too shallow, which could again lead to an unfit barrier not able to withstand the reservoir pressure that build up during several hundred years.

Requirements state that the barrier must be able to withstand all possible estimated pressures and loads. If the barrier fails, a leak can occur potentially threatening the environment.

Following an estimated PPFG and the fluid gradient of a well, it is possible to identify a suitable location for a shorter barrier of e.g. 10 meters that can be set as close to the reservoir as possible and withstand all maximum anticipated pressures. Although the industry evolves every day, the requirements of NORSOK D-010 remains the same. PSA encourages the industry to “look outside the box” and thus, new methods and technology are developed potentially challenging the specific requirements of NORSOK D-010. If a barrier of 10 meters if set at sufficient depth is able to withstand maximum anticipated pressures, while a 50 meter barrier set higher up following requirements fails, does this form an adequate basis to alter the requirements of NORSOK D-010?

9.1 Agreed Method for Barrier Verification – The Way Forward

The initial proposed approach for barrier verification was a huge success on the first attempted well. This well was used as a trial well to test the techniques and interpretations and is not presented because it did not provide a well arranged operational sequence resulting from extensive testing. As seen in Chapter 8, wells may not be identical either in well configuration or cement qualities. Subsequently, the proposed method needed alterations in order to be applied on the various wells and wells in the future. For simplicity of future work, an internally agreed method of barrier verification is presented below [52]:

- Run 1: Perforate Zone 1. Perform XLOT. Perforate Zone 2 as close to and below the tailpipe as possible. It was decided to test the longest interval between the zones to increase the chances of identifying a pressure sealing barrier. This was decided from evaluating the three wells in the case study, because cement was not found where it was expected and the team therefore had to do several perforation sets before they found good cement. The perforations must be done below the tailpipe as it is not possible to get cement above the tailpipe because of a packer [46].
- Run 2: Set CT packer to seal internally. Perform communication test from Zone 2 to Zone 1. Perform XLOT in Zone 2. Retrieve packer.
- Run 3: Lay cement in liner.
- Run 4: Tag and pressure test internal cement plug.

To ensure the agreed method would meet requirements given in NORSOK D-010, some minimum internal requirements were agreed upon [52].

- 50 meter MD from top of lower perforation to top of the reservoir, in order to meet the minimum length requirements of a cement plug in NORSOK D-010 of 50 meters.
- 50 meter MD internal cement above each perforation set. The perforations sets are considered as open holes and therefore requires a 50 meter cement pug set on a mechanical foundation, which in this method is a bridge plug.
- Total cement plug length shall be minimum 100 meter MD.
- Cement entire liner. This is to create the largest choke possible. This concept is further elaborated in Chapter 9.6.

9.2 Learning Effects

By implementing the proposed method on more wells, the team will over time improve their performance and knowledge owing to learning effects. Illustrated in Figure 9.1, repeating a procedure has proven to reduce the overall time spent and furthermore reduce cost. This figure shows how the overall time spent on P&A has been reduced resulting from learning effects. Well C is not included in this figure because it was plugged after the figure was last updated. The figure shows that there is a significant reduction in time from Well A to Well B, proving that learning effects can have a large impact on future operations.

As previously mentioned, some of the inflatable packers introduced challenges when constant pumping was required to keep the packers inflated. This caused difficulties when interpreting the pressure response from the tests. Based on this learning, other equipment was implemented. This also lead to learning about the importance of interpreting the communication test data. It is considered important to have confidence that once communication is detected, it is either well failure or plug failure [26].

For future implementation of the method, it is aimed to only perforate two zones. This is based on learnings from Well C, as it was discovered that perforating zones with a longer interval in between using a TCP would provide the same result as perforating every 30 meters. Longer intervals also saved both time and funds as only one run was needed [26].

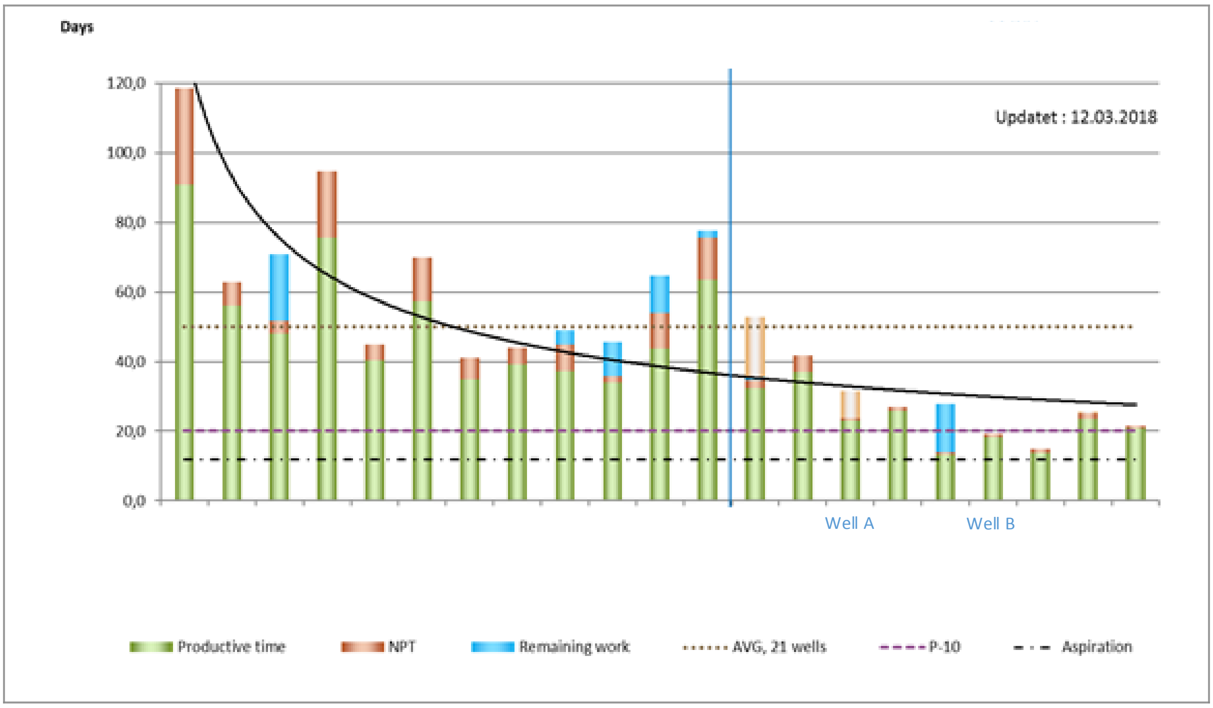

Figure 9.1 Improvement of P&A operations resulting from learning effects, modified from [52]

Another lesson learned was the use of a single TCP versus a tandem TCP. By using a tandem TCP, it is possible to check the first perforations for whether there is communication or not down to the reservoir. If there is communication, a second zone is perforated without having to POOH. A plug is further set above the first zone to isolate internally.

9.3 Time and Cost

An estimation conducted within Aker BP, showed that the use of CT was six times cheaper than using a rig [2]. As seen from the advantages in Table 4.1, the CT is faster to rig up and down because there is no need to make up stands, and reduces the overall trip time because there is no need to kill the well. Additionally, releasing the jack-up already on location to perform other activities simultaneously while the other wells were plugged, would create a positive cash flow for the company. Figure 9.1 shows how learning effects can contribute with a continuous reduction in time spent on P&A. Subsequently, time spent on plugging Well A and B using the proposed method, is considerably less compared to previous and later wells.

9.4 HSE

As mentioned in Chapter 4, CT operations require less personnel than rig operations. Additionally, not having to cut and pull casings, allowed barriers such as the XMT and the CT BOP to be rigged up at all times, making this operation highly safe both for personnel and the environment. Being able to operate in live wells with pressure at surface, CT is environmentally friendly because there is no need to pump kill fluids downhole, leaving less of a footprint on the environment. Because there was no need to perform section milling, the personnel and environment have less of an exposure to hazardous fluids and swarf handling and transportation. Based on those reasons amongst other, the proposed approach is considered to introduce personnel and environment of less exposure to dangerous operations.

9.5 Operational Risk

The CT is exposed to fatigue through constant plastic deformation when it is reeled in and out of the well, and as a result it has a short lifetime compared to e.g. drill pipes. Nevertheless, during a meeting with Daniel Tomczak 25.01.2018 is was discussed that the CT could introduce less operational uncertainties compared to a rig because e.g. section milling was not necessary [26].

One of the challenges faced during the implementation of the proposed approach was equipment failure and well failure. This is nevertheless a risk in all petroleum operations, and could be considered a learning process. Finally, a residual risk after completing any permanent P&A operation, is the risk of not being able to restore the original cap rock properties. This is a residual risk applying all P&A methods, and the results remain to be seen.

9.6 Integrity of well

By performing XLOTs and communication tests, both formation and cement bond integrity and strength are verified. As a result, there is less risk of leaks compared to verifying the cement bond integrity using a CBL, because during the proposed method both integrity and strength of barrier is verified [26].

Nevertheless, when the reservoir pressure increases in the course of several hundred years, a crack in the formation bypassing the cement plug could form, which in some cases could enter the wellbore. This can occur when the reservoir pressure builds up to the cap rock pressure. Choke of the flow will prevent the creation of a differential pressure and thus further prevent a drawdown effect. A drawdown effect in this context is considered a differential pressure allowing fluids or gases to flow through a passage. A longer cement barrier is therefore considered to provide a better choke of a potential leak because of a longer leak path with more friction compared to a shorter barrier. As discussed, a deeper and shorter barrier is considered better than a shallower and longer because there is less differential pressure. Nevertheless, should a crack occur and the barriers fail, a shorter barrier will allow more flow than a longer because of less choke. Nevertheless, there is an uncertainty in how rapid the reservoir pressure will build up, and it should be evaluated whether a shorter and deeper barrier is better owing to less differential pressure.

It should be mentioned that because a cement section will shrink during hundreds of years, oil percolation could occur. This is because the oil has less density than water and mud, and will travel upwards in cement cracks and channels following the laws of physics. This remains as a residual risk because there is an uncertainty in actual barrier length by using the proposed method, and therefore an uncertainty in choke.

9.7 Regulation and Requirement Satisfaction

A review of the results from each well in the case study, confirms that the proposed method provides results equivalent or better than methods described in NORSOK D-010, and that all wells meet the given length and sealing requirements. The Earth is permeable in variable degree and will therefore not have zero leakage rates everywhere. NORSOK D-010 requires zero leakage rate, however, there are barely any definitions of acceptable levels otherwise. The purpose of P&A is to restore the cap rock to its original condition, if the cap rock has a natural leakage why does NORSOK D-010 require zero leakage? It should be suggested to alter the requirements in NORSOK D-010 to mirror the reality. If a cap rock is not naturally sealing and instead naturally leaking, the cap rock should be restored to this condition instead of fully sealing to ensure zero leakage. A risk reduced version of zero could be considered.

10. Conclusion and Future Work

Despite plugging three diverse wells with different configurations and cement qualities, Aker BP was able to verify good liner annulus cement in all wells, resulting in an impressive track record of success. The performed XLOTs show expected values regarding formation strength at the perforated depths and it was concluded that there was sealing material outside the casing, and no hydraulic communication to the reservoir or permeable formations in the overburden.

During the implementation of the method it was experimented whether it was possible to induce shale influx by reducing the pressure in the wellbore, in case the external cement was unfit as a barrier. However, it was not possible to induce an ample amount of shale to qualify it as a barrier. This is an area that requires further investigation. In this case with two casing strings, the quality of creeping shale as a barrier is not possible to verify by using CBL, and the proposed method is thus better to verify formation as barrier. With one casing string, a CBL can be run followed by a calibration by a communication test to verify the results from the CBL. The communication test calibration can further be used on analogous wells if the logging results are identical, because it is assumed the communication test results will be identical as well [49].

Based on the results from these tests it is concluded that the proposed method provides results equivalent or better than results from the conventional CBL. The proposed method introduces test procedures so robust that it is clearly indicated whenever there is communication. In addition, the method introduced several benefits regarding HSE and a lower risk for personnel which is presented in Chapter 9. By using the proposed method, the barrier requirements given in NORSOK D-010 were achieved without mobilizing a rig on site and cutting and pulling the inner casing string. It is considered that results from the case study form an adequate basis to consider eliminating the conventional CBL tool where two casing strings exist. The evaluated method is considered to be sufficient for identifying hydraulic sealing intervals through dual cemented liners.

For future implementations of this method it could be investigated whether it is possible to perform these tests in only one run to further reduce time and cost. This would require a complete tool that perforates, isolates the well internally and simultaneously pumps fluid into the perforations. By implementing this tool, the operational sequence presented in Chapter 7 can be reduced to:

- Set downhole bridge plug to isolate the reservoir. Tag and test.

- Perforate Zone 1 and perform an XLOT.
- Perforate Zone 2 and perform an XLOT and communication test.

It would be unnecessary to set a plug with a memory pressure gauge because this would be included in the tool.

Another suggestion is implementing technology to read the pressure from the downhole pressure gauge real-time, thus avoiding having to retrieve the gauge to read pressure data. This would further reduce time and cost.

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