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MASTER'S THESIS

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Abstract

NORSOK D-010 and other standards gives a fixed length of cement for permanently plugging of wells. These lengths are not based on scientific research, but on old practice. A fixed length leads to a shift in focus from where the barriers in a well are most effective, to where in a well this length can be placed.

In the shallow zones of the Valhall field, the interval of easily verifiable external cement is shorter than what is required by the NORSOK D-010 standard. To be in accordance with the standard, the only available option might be section milling, which is an expensive and HSE critical operation. Therefore, it is desirable to look at other options. One such option is the methodology presented by Godøy et al. [1], where the length of cement is based on estimated leakage rates through the barrier. An accepted well is used as a reference, where the estimated leakage rates are set as the Upper Accepted Case (UAC). This reference case is from another operator on the Norwegian Continental Shelf (NCS), where Aker BP does not have control over the data. Because operators are held accountable for the wells they abandon, data control is essential. In this thesis, a new reference case for Aker BP is defined.

Cement is to some extent a porous medium and leakage will occur in the same way as natural formations have leakages. By looking at an accepted single barrier covering the reservoir at Valhall, and calculating the theoretical leakage rate across this barrier, the reference case that defines the UAC is set. The leakage rate is found with the use of the Darcy's law based simulation program Simeo WellCem. The new Aker BP reference case can then be used to estimate equivalent cement lengths in other parts of the well, or other wells.

At shallower depths, the pressure and temperature conditions will be less severe, while the cement will typically be of lower quality. To compare these conditions to the reference case, cement samples from the shallower depths are tested to get realistic permeability data, and the corresponding leakage rates compared to the UAC. In the studied case, it was seen through leakage modeling that one could reduce the length requirements compared to the 2 x 30 meters defined by NORSOK D-010 (verified annular cement). The presented risk based methodology has a more scientific foundation and combines testing of leakage through cement with theoretical models for leakage. This approach can be used for dispensation request, or to discover and mitigate risk where longer barriers than these 2 x 30 meters are needed to achieve the UAC.

Acknowledgements

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I would like to use this opportunity to thank the people that has made this work possible.

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List of Abbreviations

BOE – Barrels of Oil Equivalent
BOP – BlowOut Preventer
CBL – Cement Bond Log
DHSV – Downhole Safety Valve
DP – Drilling Platform
DPZ – Distinct Permeable Zone
ECD – Equivalent Circulating Density
FBP – Formation Breakdown Pressure
FCP – Fracture Closure Pressure
FIT – Formation Integrity Test
FPP – Fracture Propagation Pressure
FRP – Fracture Re-open Pressure
GPS – Gallons Per Sack
HC – HydroCarbons
HPHT – High Pressure, High Temperature
HSE – Health, Safety and Environment
ISO – International Organization for Standardization
LOP – Leak-Off Pressure
LOT – Leak-Off Test
LPLT – Low Pressure Low Temperature
LWIV – Light Well Intervention Vessel
MD – Measured Depth
MSD – Minimum Setting Depth
MSL – Mean Sea Level
NCS – Norwegian Continental Shelf
P&A – Plug and Abandonment
PAF – Plug and Abandonment Forum
PDO – Plan for Development and Operations
PIT – Pressure Integrity Test
PP – Pore Pressure
PSA – Petroleum Safety Authority
PWC – Perforate, Wash and Cement
TOC – Top Of Cement
TVD – True Vertical Depth
UAC – Upper Accepted Case
UKCS – United Kingdom Continental Shelf
Vm – Vertical Meters
WBE – Well Barrier Element
WH – WellHead
WL -WireLine
XLOT – Extended Leak-Off Test
XT – Christmas (X-mas) Tree

1. Introduction

When permanently Plugging and Abandoning a well (P&A), the barriers in that well are intended to stop HydroCarbon (HC) migration to the surface for eternity. Portland cement is usually the material used in these barriers, and it is a permeable medium. To stop flow through the barriers in abandoned wells on the Norwegian Continental Shelf (NCS), NORSOK standard D-010 has defined minimum length requirements for barriers. These barrier lengths are based on common cementing practice in the industry, and not on scientific research [2].

1.1. Background and Purpose of Thesis

The "one model fits all" approach in NORSOK D-010 does not consider the different conditions a well can have. Some sources of inflow are HPHT (High Pressure, High Temperature) reservoirs with a high flow potential, while others are hydrostatically pressured zones with very low potential for flow. Still the requirements are the same. A risk based approach to these conditions will give a more realistic picture of the actual risks involved.

A study performed by Godøy et al. [1] shows an alternative approach for calculating cement length based on leakage rates through the cement. This methodology ensures that the barrier lengths are based on a more scientific, risk based approach instead of industry practice. This thesis will focus on the methodology from this study, and build up a reference case from Aker BP portfolio of wells, instead of using a well from another operator where no control over the quality of the data is possible. As operators are held accountable for the wells they have abandoned, data control is essential.

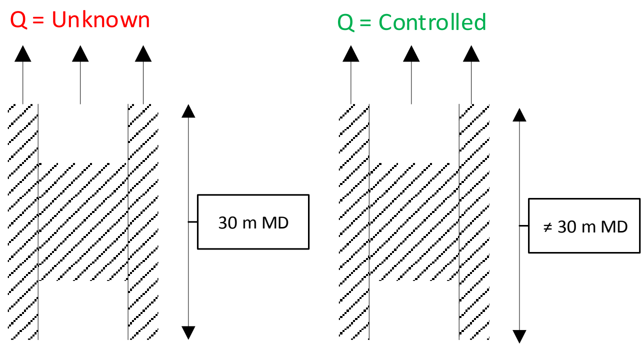

Figure 1-1: Flowrate is more important than cement length

A single accepted reservoir barrier from a well on the Valhall field will be used as a reference case, where the calculated leakage rates across this barrier is set as an Upper Accepted Case (UAC). This UAC can then be compared to leakage rates of barriers placed under different conditions, and a risk based approach to cement lengths can be obtained. In this thesis, the UAC will be compared to permeability tested cement. With the use of this methodology, the leakage rates are controlled (see Figure 1-1), while in the "one model fits all" methodology of NORSOK D-010, they are unknown. The presented methodology could also aid setting length requirements for other plugging materials than Portland cement, and thus avoid deciding the length of these materials based on the performance of Portland cement.

1.2. Valhall

The Valhall field is undergoing redevelopment because of subsidence and expansion of the infrastructure. As a part of this process, all the wells connected to the Valhall DP platform needs to be permanently P&A. In the overburden at Valhall, several Distinct Permeable Zones or DPZ (Aker BP's equivalent to sources of inflow) need to be isolated with a primary and secondary barrier. Because cement behind the second casing string is not verifiable, the interval containing suitable formation (seal) for barrier placement covering one of these shallow zones has less verifiable length than what is required by NORSOK D-010. In Figure 1-2, which shows one of the wells at Valhall DP, the available interval is only 30 meters, while NORSOK D-010 requires a minimum of 2 x 30 meters (logged and verified annular cement). The only accepted options to gain the necessary interval may be cut and pull, or section milling; an expensive and HSE (Health, Safety and Environment) critical operation. The method for calculating plug lengths described in this thesis is intended to be used as documentation for dispensations when needed. Further, it will also give the necessary tools to discover and do necessary adjustment when the 2 x 30 meters of NORSOK D-010 is not sufficient.

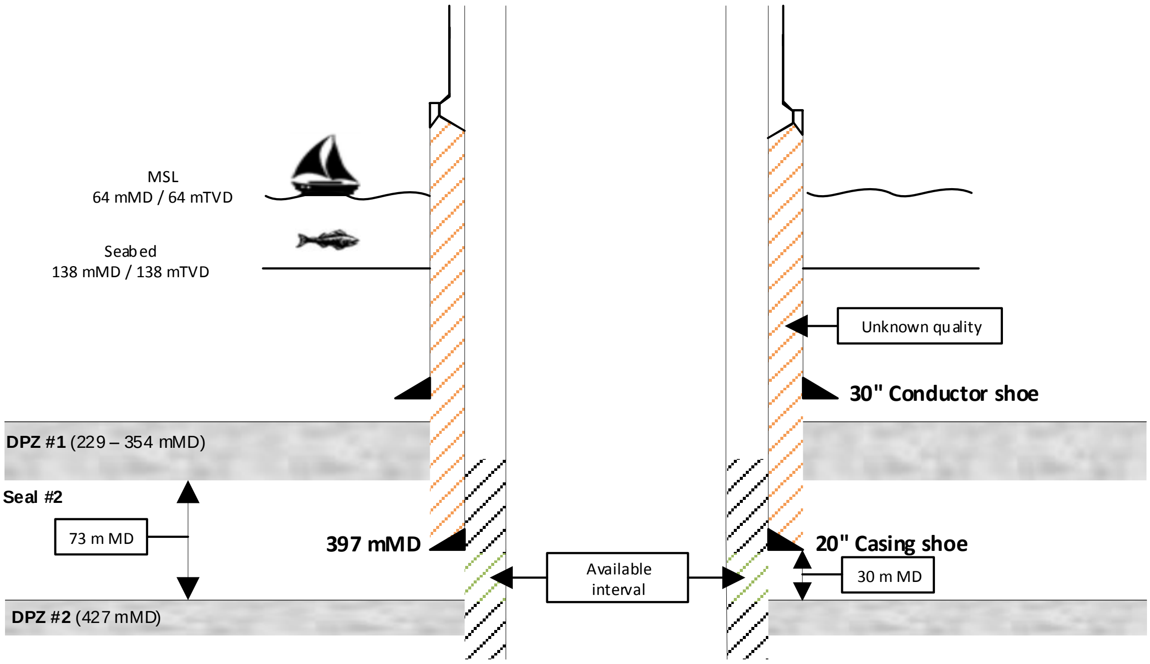

Figure 1-2: Too short interval for two barriers at Valhall at a Valhall DP well

1.3. Structure of Thesis

The thesis it structured in the following way:

- Chapter 2-3: P&A with rules, regulations and standards, both on the NCS and in other countries.
- Chapter 4: Portland cement, the most common plugging material.
- Chapter 5: Valhall, a giant oil field.
- Chapter 6: A study in risk based approach for calculating cement barrier lengths.
- Chapter 7: Leakage and ways to estimate it.
- Chapter 8: Permeability testing of cement from Valhall DP.
- Chapter 9: Use of leakage calculator to find suitable barrier lengths.

1.4. Findings

Results from Darcy's law based simulations in this thesis shows that barriers located in shallower zones at the Valhall field can be plugged with a shorter length of cement than the required lengths stated in NORSOK D-010, and still have a leakage rate below the accepted reference cases.

As Portland cement is an inexpensive material, it is recommended that the use of this methodology is complemented with an extra safety margin using unverified external cement (see Figure 1-3). The questionable external cement (which may or may not be of good quality) can be used in addition to the lengths calculated using the risk based approach. By adding a cement plug that covers an extra length (e.g. 30 m) in the same interval as unverified external cement, the total cement length will be longer than the calculated accepted length. This will ensure that the actual leakage is well below the UAC.

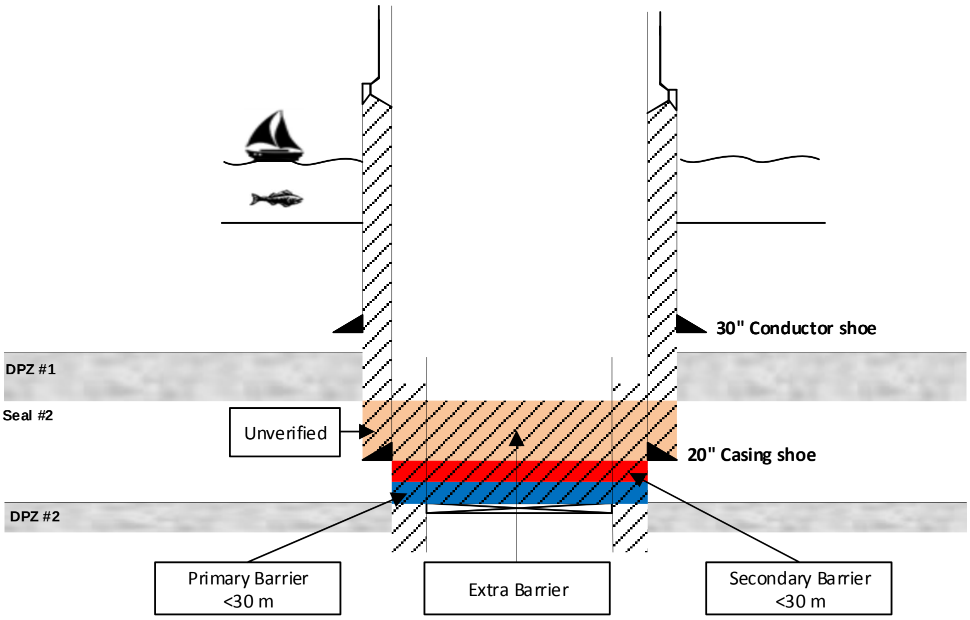

Figure 1-3: Suggested method

1.5. Further Qualification of Method

When the outline of the thesis was set, the plan was to have three different tests for permeability. Because the "sandwich joints" (two consecutive casing strings with cement between) could not be correlated with Cement Bond Logs (CBL) of sufficient quality, testing of sandwich joints were postponed (see Chapter 8.4). When testing sandwich joints, micro-annuli between cement and casing strings will be part of the effective permeability measured. As a result, micro-annuli are not considered in this thesis, but should be considered when the data is available. Sandwich joints of sufficient quality have been retrieved at a later date. However, testing of these has been set to a time after the deadline of this thesis.

For the leakage calculations, only one model (Simeo WellCem) has been used in the thesis. However, it will strengthen the risk based approach by using several different models for the leakage calculations. The IRIS leakage calculator is in development and for future work this could be tested.

2. Plug & Abandonment

After oil and gas has been produced from a well for a number of years, and it is no longer economically feasible, it needs to be plugged. Plugged wells need to remain plugged with respect to an eternity perspective, and this is no simple task.

Lucrative oil prices for many years has led to a boom in the number of drilled wells, and a significant backlog in P&A of wells. To deal with this backlog, the Plug and Abandonment Forum (PAF) was established in 2009. At the forum of 2015, Spieler and Øia showed that as many as 2545 wellbores are required to be plugged on the NCS in the future [3]. In 2014 Chairman of PAF, Martin Straume showed an estimate saying that it will require 15 rigs working full-time for the next 40 years to be able to plug existing and future wells [4]. With rig-rates of that year, a rough calculation gave a total cost of 876 billion NOK [4]. The taxation system in Norway is built up in such a way that the companies can deduct costs for P&A on their taxes, meaning that a large amount of the costs for P&A is actually carried by the Norwegian community [5]. The main cost driver is the rig costs, and more specifically the time the rig uses for the P&A operation. By using the rough estimate of PAF chairman Straume from 2014 [4], a one-day reduction on all wells, would reduce the total cost by approximately 25 billion NOK.

2.1. P&A Operation

Before starting the P&A operation, information on the well conditions must be acquired through data gathering and well logging. It is not uncommon for older wells to lack essential documentation, especially if the ownership off the well has changed. In addition, the uniqueness of every well makes the P&A operation very different from well to well, where some wells are relatively simple to P&A, others are more complex. Many factors can increase the complexity of a P&A operation, but some examples are:

- Limited access to parts of the wellbore due to e.g. shifting in the overburden caused by tectonic movements or subsidence (see Figure 2-1).

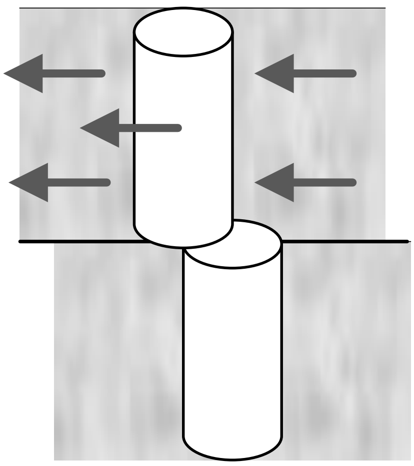

Figure 2-1: Shifting in overburden causing limited access

- Lack of information from design and construction of the well. With current technology, it is not possible to log through more than one casing string, so lack of information on cement behind second casing string is a challenge (see Figure 2-2) [6].

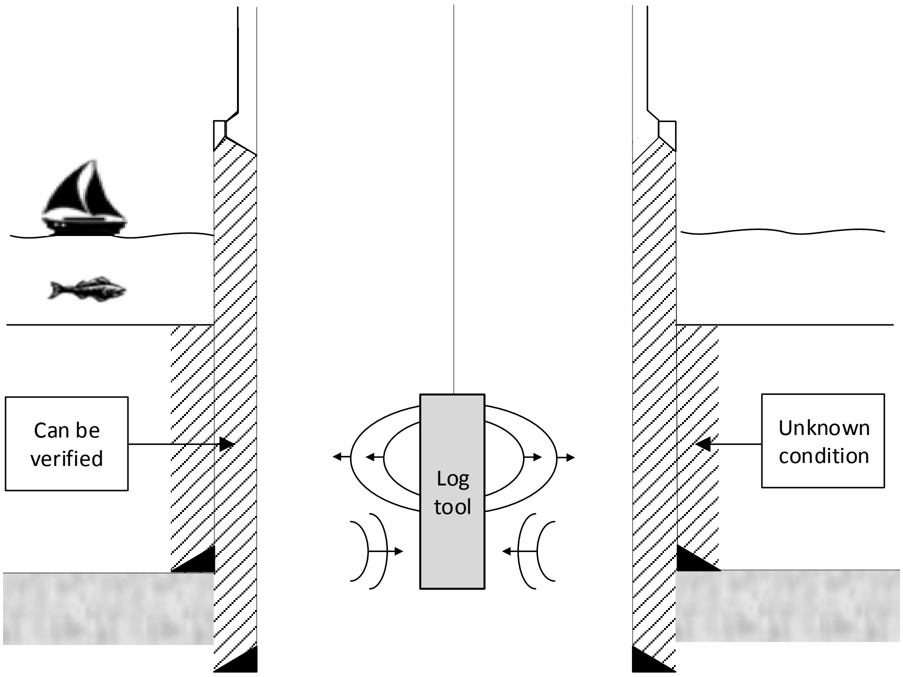

Figure 2-2: CBL logging can only be performed through one casing string.

- Many wells have more than one source of inflow, and/or are multilateral wells, meaning that cross-flow barriers or several sets of primary and secondary barriers may be needed (see Figure 2-3).

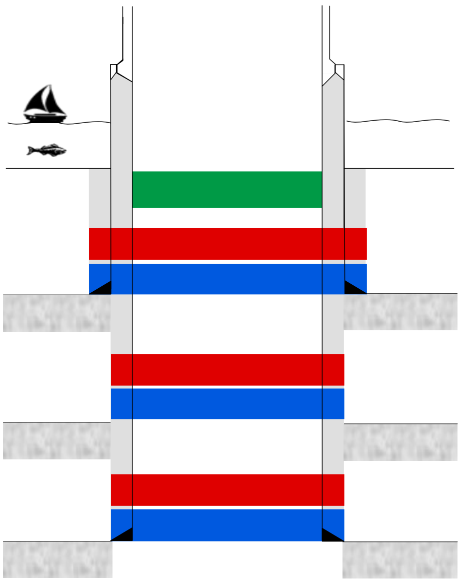

Figure 2-3: Well with three sources of inflow.

- Short interval between sources of inflow, may cause problems in meeting length requirements for primary and secondary barrier. In Figure 2-4 four sources of inflow can be seen from a specific well at Valhall, where there is 11 mMD of suitable formation between two of them. This interval is shorter than the barrier length requirement in NORSOK D-010.

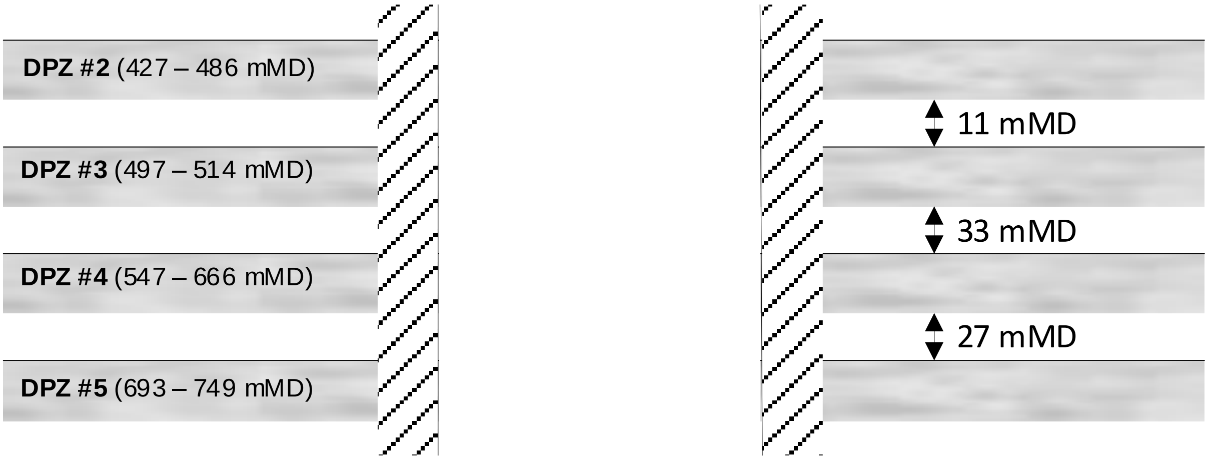

Figure 2-4: Short interval between sources of inflow from a specific well at Valhall [7].

- Lack of cement behind casing where placement of barrier is desired (see Figure 2-5). As unsupported casing is not qualified as a well barrier element (see Chapter 2.1.5), this would not constitute as a barrier.

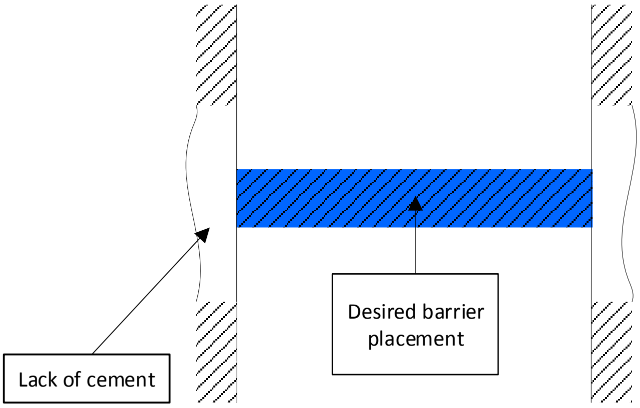

Figure 2-5: Lack of cement behind casing

All these elements (and more) makes it impossible to give a specific recipe on how to perform P&A. However, some general elements presented in the following chapters are normally present in a P&A operation.

2.1.1. Preparing the Well

To ensure access to the well, the Down Hole Safety Valve (DHSV) is retrieved via WireLine (WL) when applicable. The DHSV is a fail-safe device that blocks flow. To allow flow, hydraulic pressure is applied to keep the valve open. In absence of this pressure, the valve is shut (e.g. emergency situation or loss of system control). NORSOK D-010 requires a DHSV to be installed in all wells that penetrates a HC bearing zone, or wells with reservoir pressure high enough to lift fluids to seabed or higher [8]. The DHSV shall be placed a minimum of 50m below seabed.

It is worth noting that the placement is minimum 50m below seabed both for subsea wells with the WellHead (WH) at seabed, and for platform wells with WH at surface (see Figure 2-6).

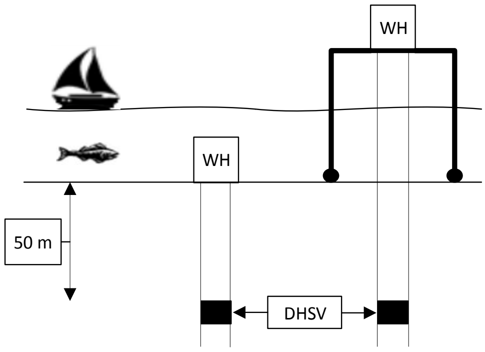

Figure 2-6: Placement of DHSV

2.1.2. Killing the Well

If a well has been producing, it is normally "live", meaning that the hydrostatic pressure from the fluid in the well is less than the formation pressure. This pressure difference will cause flow if allowed. To "kill" a well means that denser fluid is added to the well, so that the hydrostatic pressure exceeds the formation pressure. There are several ways to do this, but bullheading (Chapter 2.1.2.1) and reverse circulation (Chapter 2.1.2.2) are the most common methods [9].

2.1.2.1. Bullheading

To kill a well with the use of bullheading, dense fluid (kill fluid) is pumped into the well against the pressure in the well (see Figure 2-7). The increased hydrostatic pressure will exceed the formation pressure, and the formation fluid will reenter the formation. When the tubing is filled with kill fluid, the well is no longer live [9].

If the well contains dangerous gases (e.g. H_2S), bullheading is often performed as no fluid is circulated back to surface. However, during bullheading, the well fluid will take the path of least resistance, meaning that it normally will enter the weakest zone. These zones might not be strong enough to take the increased pressure, and therefore bullheading is considered a risky procedure [10].

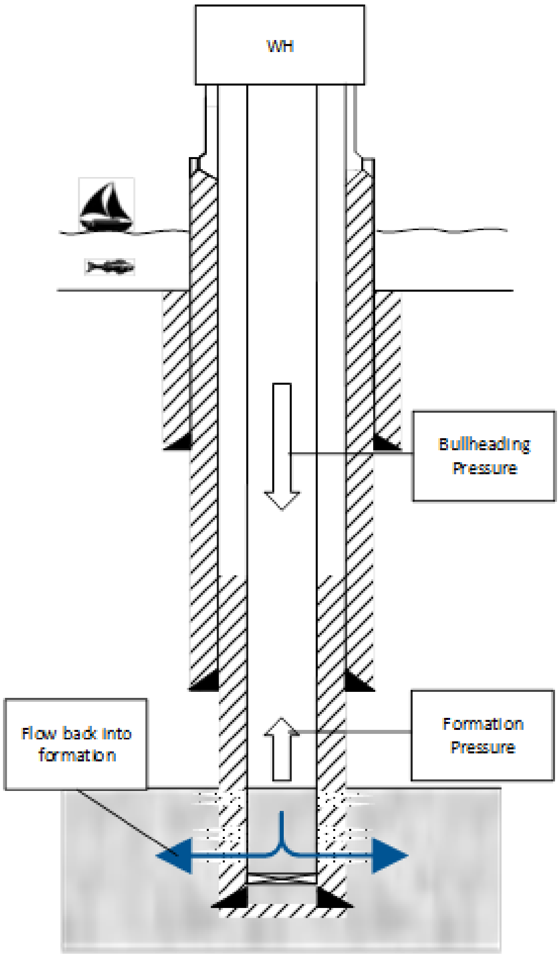

Figure 2-7: Killing of well with the use of Bullheading

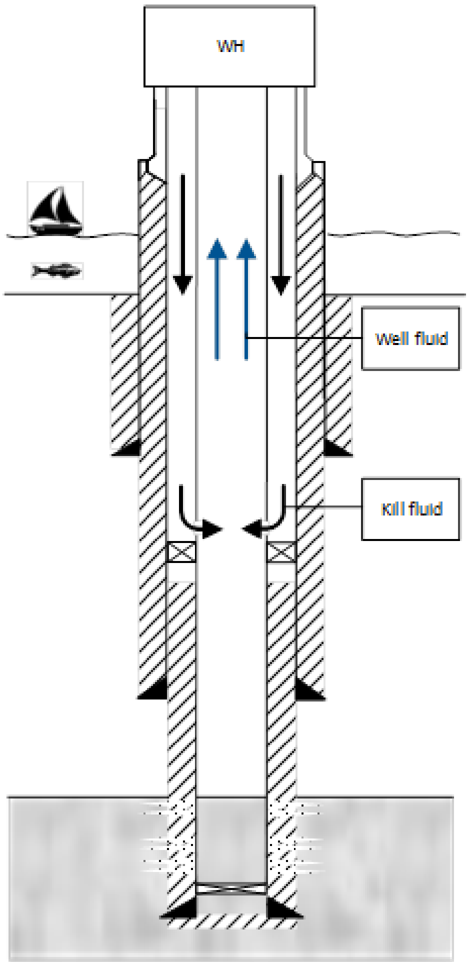

Figure 2-8: Killing of well with the use of Reverse circulation

2.1.2.2. Reverse Circulation

During reverse circulation, the kill fluid is pumped via the annulus and into the tubing through an access point (e.g. perforations) above the production packer (see Figure 2-8). As the kill fluid enters the tubing, excess fluid in the tubing is circulated out of the well. When the tubing is filled with kill fluid, the well is no longer live [9].

As this operation takes circulation back to surface, there is less stress on the formation. However, as there is need for an access point, the tubing integrity may be compromised (e.g. if perforations are used). For P&A, this is not normally an issue, as the tubing above the production packer is normally retrieved (see Chapter 2.1.4), and is therefore not meant to be part of the barrier envelope.

2.1.3. Removal of XT and Setting of BOP

To maintain the necessary well control when changing out the christmas tree (XT) with a Blow Out Preventer (BOP), temporary barriers needs to be set. The placement of these barriers depends on the type of XT (i.e. vertical or horizontal).

Vertical XT

For a vertical XT the tubing hanger is in the WH, located below the XT. This means that the tubing can be left in place when changing out the XT.

NORSOK D-010 (see Chapter 3.4), depicts some requirements for the barriers when removing a XT. For the removal of a vertical XT, the barrier requirements depend on the type of fluid in the well, and the possibility to monitor the primary well barrier. However, normally a deep set mechanical bridge plug is set as a primary Well Barrier Element (WBE) (see Chapter 3.4.4.1), while a shallow set mechanical bridge plug is set as a secondary WBE [8]. For further details the reader is referred to NORSOK D-010.

Horizontal XT

In a horizontal XT, the tubing hanger is located in the XT, meaning that the tubing needs to be retrieved (pulled) prior to nippeling down the XT and nippeling up the BOP.

According to NORSOK D-010, a deep-set plug shall be set before pulling the tubing, and a shallow set plug shall be placed inside the production casing after pulling the tubing, but before nippeling down the XT [8].

BOP

After the XT has been nippled down, a BOP is nippled up for well control.

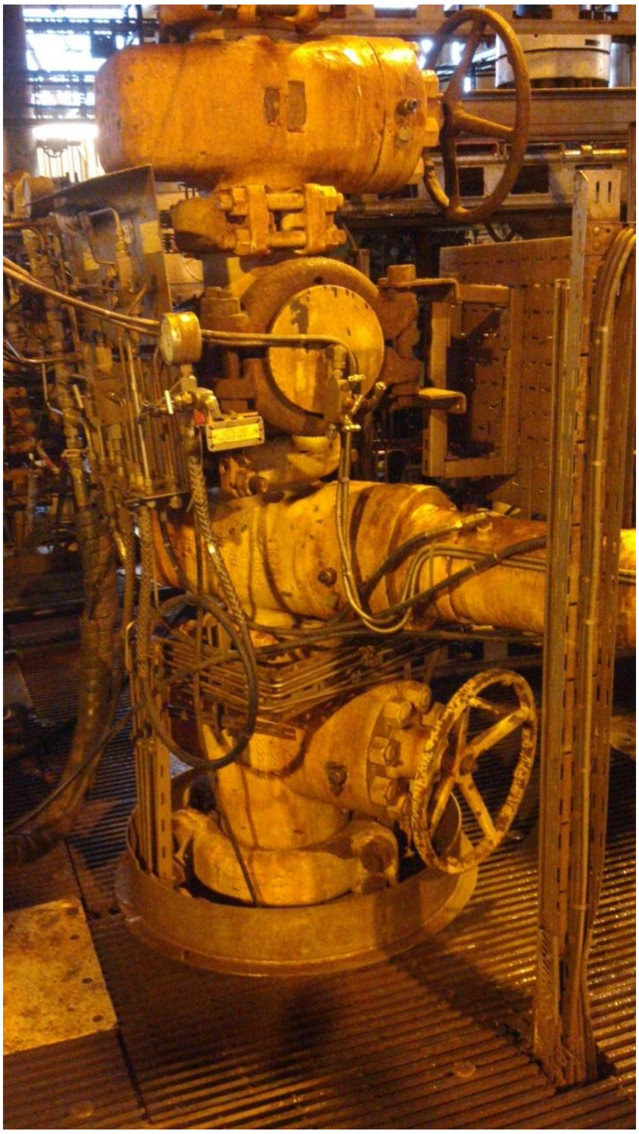

Figure 2-9: XT at Valhall DP

2.1.4. Pulling Upper Completion

The part of the completion system that is found above the production packer is often referred to as the upper completion. While the lower completion is often left in hole, the upper completion is often removed, as it can cause problems during P&A. Some examples of problems are:

- Verification of WBE can be hindered by the tubing. As mentioned in Chapter 2.1, it is not possible to log through more than one casing string.
- If there are control cables attached to the tubing, these must be removed as they can form leakage paths [8].
- Lack of cement behind casing, may cause the need of access to the casing outside the tubing.

2.1.5. Setting Primary and Secondary Barriers

To permanently seal of the reservoir(s) and other sources of inflow from the surface, primary and secondary barriers are set according to the requirements in Chapter 3.4. The primary barrier work as a seal of the formation, preventing undesired flow caused by the pressures below, while the secondary barrier is the backup barrier when two barriers are required to seal of a zone.

In the presence of more than one source of inflow, several sets of primary and secondary barriers may be necessary (see Figure 2-3).

Requirements depicts that barriers needs to cover the entire cross-section of the well, while steel casing is not qualified as a WBE without being supported by cement or other plugging material (see Figure 2-5) [8]. To achieve acceptable WBE, several cement placement techniques may be needed to place cement both inside casing and in annulus (see Chapter 4.1.2).

2.1.5.1. Section Milling

If the cement in the annulus cannot be verified (e.g. lack of cement logging), it lacks the properties necessary (i.e. not "good" cement), or if there is no cement in the interval in the first place, a section of the casing can be milled into pieces and removed (section milling). Although other techniques are now commonly used for placement of cement in uncemented annulus intervals (see Perf, Wash and Cement (PWC) in Chapter 4.1.2.2), section milling was the traditional way to gain access to those areas of a well [9].

In addition to being a complex rig-based operation, and thus requiring a rig with a high rig-rate, section milling is a time consuming operation [9] [11]. The operation in itself is also challenging:

- Metal shavings from the casing (swarf) are sharp, and causes HSE handling issues when brought to surface.
- Transport of swarf to the surface needs a highly viscous fluid. The combination of this fluid and the swarf results in a fluid with an equivalent circulating density that may be higher than the fracture gradient of the formation.
- Circulation of swarf through equipment is a source of wear and damage.

Therefore, section milling is avoided when possible.

2.1.6. Environmental Barrier and WH removal

After the necessary primary, secondary and cross-flow well barriers are set for the sources of inflow, the well and exposed zones due to casing retrieval must be sealed off from the external environment [8]. This is the reason for setting an open hole to surface well barrier (also referred to as environmental barrier)

When the open hole to surface well barrier is set, all that remains is to remove the WH and other equipment, and abandon the well permanently. To not obstruct future activities (e.g. fishing), the WH needs to be cut at a depth that ensures no "stick-up". When the WH is retrieved, the seabed must be inspected to make sure that no other obstructions are left behind [8]. Figure 2-10 shows a schematic of a well after P&A is complete.

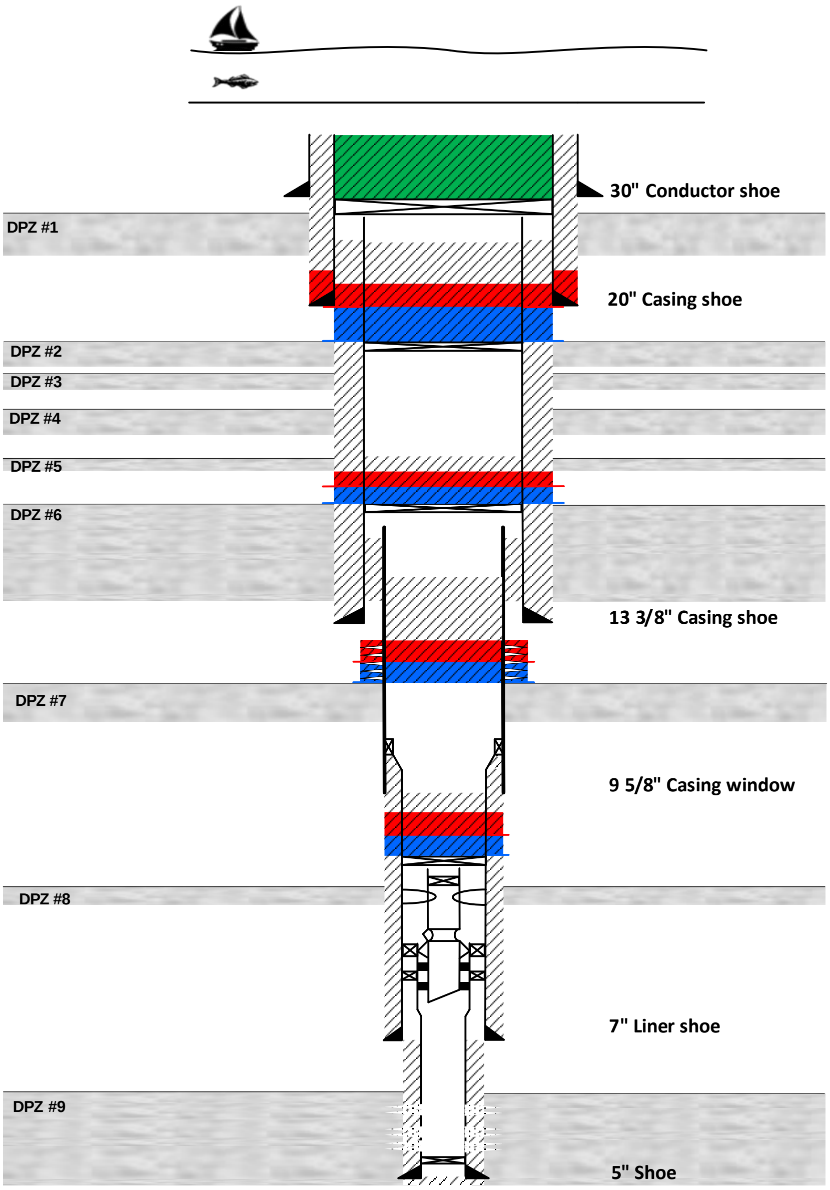

Figure 2-10: Schematic of actual well after P&A is complete

2.2. Cost of P&A

Many factors cause an increase in cost for P&A. However, the main driver is time used, as rig-rates constitute a large percentage of the cost. In the example by PAF chairman Straume mentioned earlier, a daily rig-rate of 300 000 USD (≈2.3 MNOK) was used [4]. In addition, an overhead cost of 2.2 MNOK was added [4], resulting in a daily cost of 4.5 MNOK. Although these numbers for rig-rate are relatively old, the principle is the same. In Figure 2-11 the daily cost is plotted against days used, and the 35 days from Straume's example is added, where total rig cost exceeds 150 MNOK per well [4]. In Figure 2-12 it can be seen that for the P&A campaign of Valhall DP, the average time used is approximately 50 days (May 2018) resulting in a cost of 225 MNOK per well using the same cost estimate.

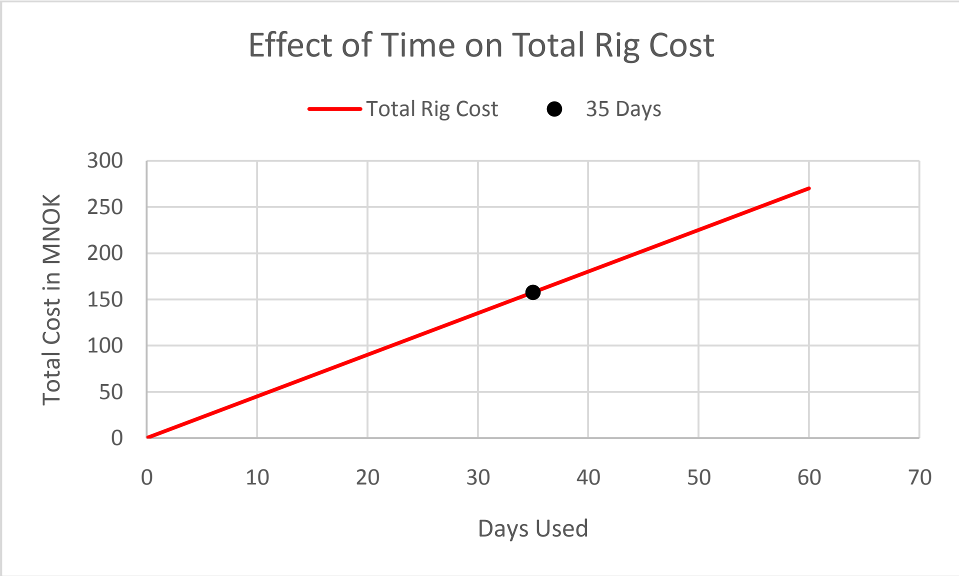

Figure 2-11: Effect of time on cost of P&A

To lower the cost of P&A, a high focus has been put into reducing the time used. Technology such as Perforate, Wash and Cement (PWC) has made a significant impact, but also the use of Light Well Intervention Vessels (LWIV) for some operations has lowered the cost significantly as the daily cost of these vessels are lower [12].

Another way to reduce the time spent, which has been successfully used is to do P&A in larger campaigns. This way, a learning outcome can be gained, as different P&A phases can be repeated with increased efficiency (e.g. retrieval of DHSV from all wells with LWIV in a batch). As Figure 2-12 shows, the time spent on Valhall DP wells has been reduced significantly thanks to continuous improvement processes.

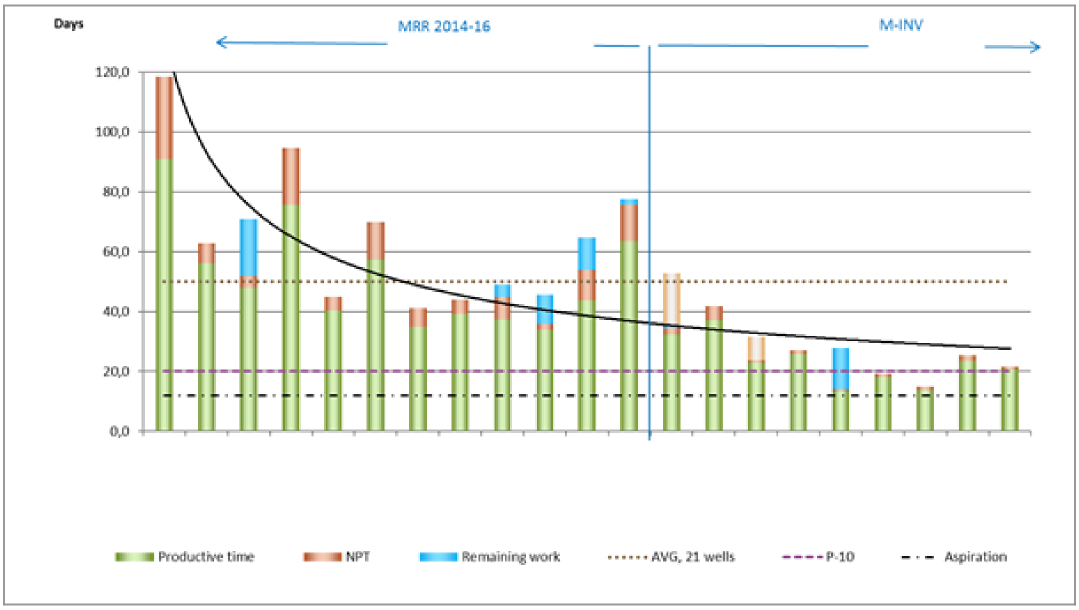

Figure 2-12: Continuous improvement processes effect on time used for P&A at Valhall DP [13]

3. Rules and Regulations

All oil and gas related activities on the NCS are subject to Norwegian laws and regulations. The Petroleum Safety Authority (PSA) is the supervisory authority, responsible of issuing regulations on safety and working environment in the oil and gas industry [14].

Regulations in Norway, unlike many other countries focuses on requirement of functionality. Meaning that the regulations do not give a detailed way to achieve a certain goal, but rather the goal itself. The operator is then free to achieve the goal in the way they seem prudent, but it also leaves them responsible.

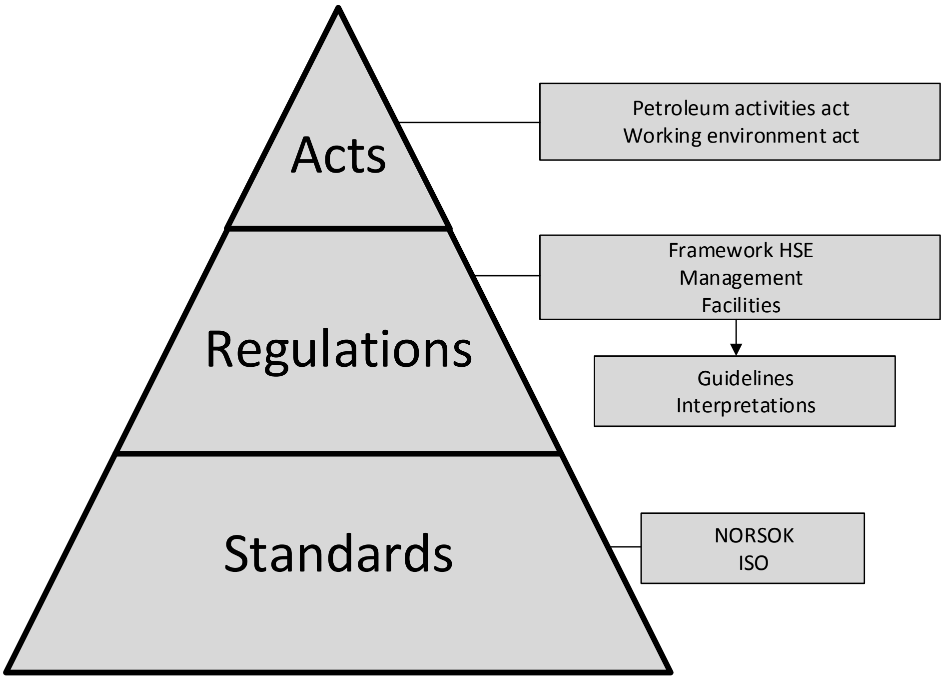

Figure 3-1: Regulatory hierarchy

3.1. Acts

At the top of the regulatory hierarchy (see Figure 3-1) are the acts. Especially two acts are of importance here; "Petroleum Activities Act" controlling the overall requirements to safety, and "Working Environment Act" controlling the working environment.

For P&A, §5-1 in the Petroleum Activities Act is of special interest. §5-1 requires a decommissioning plan at least two years before the expected end of use of the facilities. This plan must contain suggestions for future use of the facilities [15].

3.2. Regulations

Beneath the acts in the regulatory hierarchy, regulations are found. The most important one of these is the Framework HSE regulation, which depicts safety; both organizational and operational [14].

Other Regulations are:

- Management
- Facilities
- Activities
- Technical and Operation Regulation
- Working Environment Regulation

To help understand the regulations better, there are also guidelines and interpretations, which clarifies specific sections even further.

Two sections in the regulations are of special interest for P&A operations:

The Facilities Regulation section 48 "Well barriers" states: "*When a well is temporarily or permanently abandoned, the barriers shall be designed such that they take into account well integrity for the longest period of time the well is expected to be abandoned.*" [16]. For P&A this period of time will be the unforeseeable future, and is why NORSOK uses "eternity perspective" [8].

The Activities Regulation section 85 "Well barriers" states: "*During drilling and well activities, there shall be tested well barriers with sufficient independence. If a barrier fails, activities shall not be carried out in the well other than those intended to restore the barrier*." [15].

3.3. Standards

At the bottom of the regulatory hierarchy, standards are located. They depict ways to do operations, which ensures that acts and regulations are fulfilled. These and are the most important documents for the companies.

Among these standards the NORSOK standards are found. NORSOK stands for "The Norwegian shelf's competitive position" (Nor: NORsk SOkkels Konkurranseposisjon). NORSOK standards are developed in a cooperation between operators, suppliers, service companies, maritime industry and the PSA [17].

As P&A is covered in NORSOK D-010 "*Well integrity in drilling and well operations*", this is the standard of interest for this thesis [8]. Companies may have their own standards and routines, as long as they fulfill (or are stricter than) NORSOK demands.

3.4. NORSOK D-010

The first edition of NORSOK D-010 was published in 1997, while revision 4 (current edition) was published in 2013 [18]. NORSOK D-010 states the minimum requirements to maintain the well integrity during well operations, where well integrity is defined as "*application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well*" [8].

NORSOK separates between temporary abandonment and permanent abandonment, where permanent abandonment is considered in this thesis.

3.4.1. Barrier Requirements

In NORSOK D-010 a well barrier is defined as *"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"* [8]. One well barrier could be shared for several wellbores when applicable.

3.4.1.1. Well Barrier Elements

Each well barrier consists of several well barrier elements (WBE), to ensure that the well barrier covers the entire cross-section of the well.

Example of WBE's that forms a well barrier:

- In-situ formation
- Annular cement
- Casing
- Cement plug

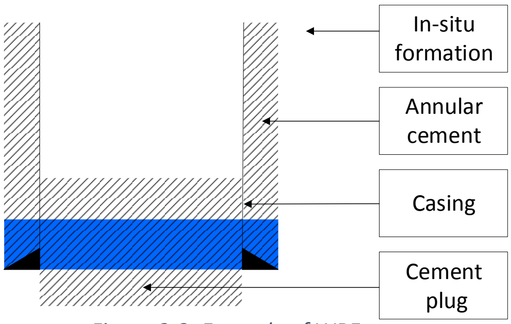

Figure 3-2: Example of WBE

3.4.1.2. Types of Well Barriers

There are four main types of barriers, each with a different purpose.

Cross-flow Well Barrier:
Barrier used to prevent flow between formation zones.

Open Hole to Surface Well Barrier:
Barrier located at the top of the abandoned well, right beneath seabed. It is set to isolate the open hole from the environment, and is sometimes called environmental barrier. This barrier is not set to withstand pressures from the reservoir(s), but is meant to isolate formations that are exposed when casings are cut and pulled [8].

Primary Well Barrier:
Main security to prevent flow from a potential source of inflow. This is the barrier that is in contact with the pressures from the reservoir(s), and should be able to withstand those conditions.

Secondary Well Barrier:
As a part of the two-barrier philosophy, this barrier acts as a backup to the primary well barrier, and should meet the same requirements as the primary well barrier.

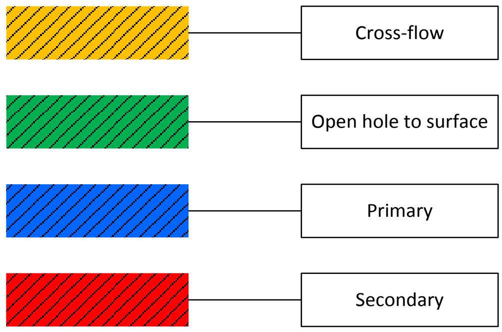

Figure 3-3: Color used for the different barrier types

3.4.1.3. Number of Barriers Required

How many barriers are required in addition to the open hole to surface well barrier depends on the flow potential and what type of fluid is to be contained.

One well barrier (see Figure 3-4) is enough when [8]:

- Barrier is set to prevent cross-flow between formation zones
- Formation is normally pressured, with no HC, and potential for flow to surface is absent
- Formation is abnormally pressured, containing HC, but with no potential for flow to surface

Figure 3-4: Wells where only one barrier is needed in addition to open hole to surface well barrier

Two well barriers (see Figure 3-5) are required when [8]:

- The formation is HC bearing
- Formation is abnormally pressured, and potential for flow to surface is present.

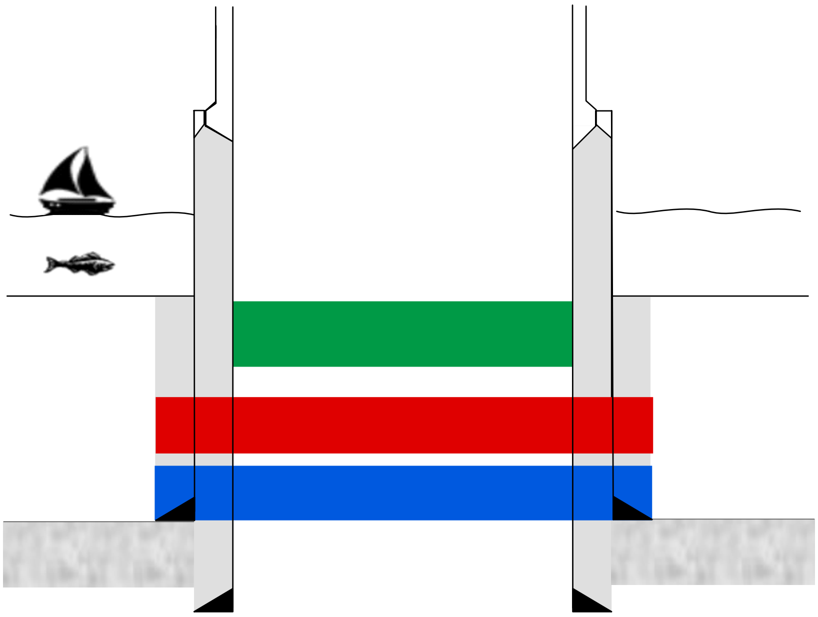

Figure 3-5: Well with primary, secondary and open hole to surface well barrier

NORSOK does not define what is to be considered a source of inflow, leaving the operators free to define their own. Another operator on the NCS uses 0.1 mD [1] as a limit in their operations [9].

3.4.2. Material Requirements

A well barrier could be made up of different materials, however NORSOK D-010 states: "*A permanent well barrier should have the following characteristics:*

a) provide long term integrity (eternal perspective);
b) impermeable;
c) non-shrinking;
d) able to withstand mechanical loads/impact;
e) resistant to chemicals/ substances (H_2S, CO_2 and hydrocarbons);
f) ensure bonding to steel;
g) not harmful to the steel tubulars integrity." [8]

The most used material on the NCS is Portland cement (other examples are shale, geopolymers and Sandand). It will be shown that like most barrier materials this is not an impermeable material (see Chapter 8).

NORSOK D-010 differs distinctly between the wording "should" and "shall" [8].
"Shall": Marks that no deviation is to be made without acceptance of all parties.
"Should": Marks that this is the preferred solution.
This means that even though Portland cement does not fulfill all of the characteristics, it is not in contradiction due to the wording "should".

[1] mD – Milli-Darcy

3.4.3. Placement of Barriers

For placement depth of the three types of formation integrity barriers (primary, secondary and cross-flow well barriers) NORSOK D-010 states "*The base of the well barriers shall be positioned at a depth were formation integrity is higher than potential pressure below (…)* " [8].

NORSOK D-010 defines "formation integrity pressure" as "*collective term to describe strength of the formation. This can be either FIT/*PIT *or the interval between fracture breakdown pressure and fracture closure pressure*" [8].

The open hole to surface well barrier is not meant to withstand pressures from the reservoir(s), therefore formation integrity is not a concern when placement depth is decided for this barrier [8].

3.4.3.1. Determining Formation Integrity

There are several ways to determine the formation strength/integrity [8]:

Formation / Pressure Integrity Test (FIT/PIT)

Testing the formation with a given pressure, to confirm that the formation can hold that pressure. It is worth noting that this test does not give any information on how much the formation can hold, only if it can hold the test pressure.

Leak-off Test (LOT)

During this test, pressure vs volume is monitored while fluid is pumped into a closed well. Once the fluid starts to leak off into the formation, there will be a deviation on the linear pressure vs volume curve, marking the leak-off pressure (LOP).

Extended Leak-off Test (XLOT)

During the extended leak-off test (see Figure 3-6), the pumping is continued after the deviation obtained on the LOT. This will result in fracturing of the formation, giving a sudden drop in pressure (formation break-down pressure, FBP). At this point the pressure will remain close to constant even with more fluid being pumped in, due to the fractures propagating further (fracture propagation pressure, FPP). The pumps are then shut in, and later the choke is opened to allow excess fluid to flow back. At first there will be a period where pressure is maintained by the still open fractures before it starts to drop. Once the fractures close, the pressure decreases more rapidly. When the pressure drop becomes linearly, the fractures have closed, and the fracture closure pressure (FCP) is known. This test is then repeated to verify the data. It is worth noting that this test damages the formation, leading to a lower LOP for the repeated test(s), and lower formation integrity. In turn, this will lead to the pressure needed to re-open the fractures (FRP) is significantly lower than the original LOP.

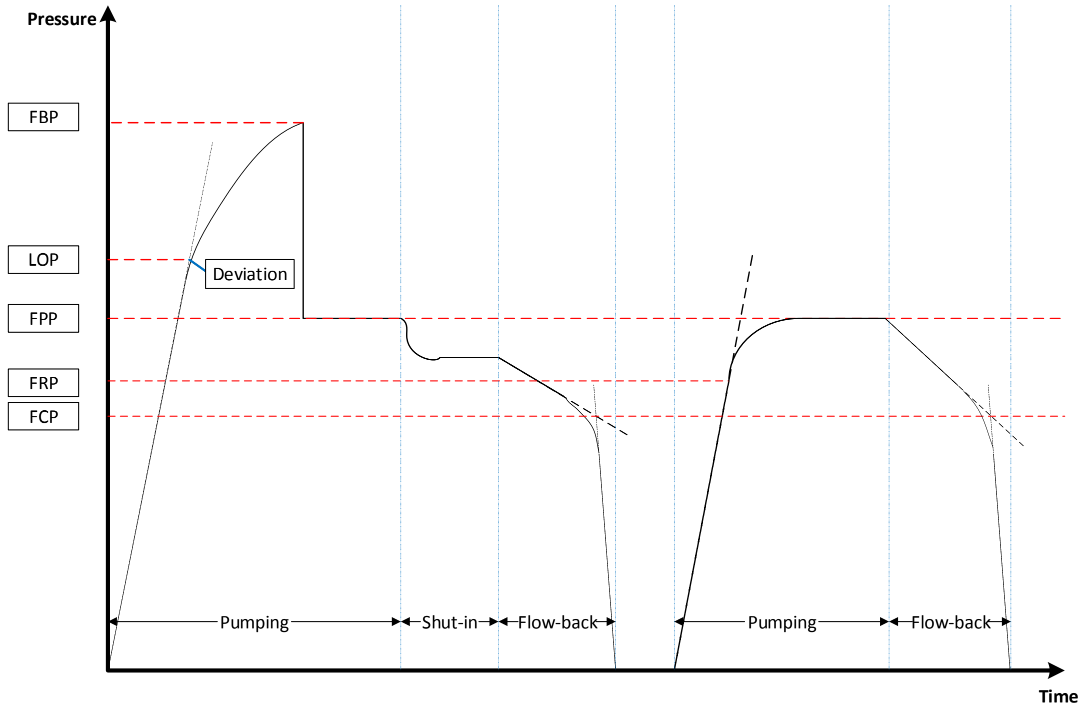

Figure 3-6: Theoretical XLOT

3.4.3.2. Minimum Setting Depth

To find the point where the potential pressure below is equal to the formation integrity, the virgin reservoir pressure can be used in combination with the hydrostatic pressure of the worst-case medium. In HC bearing wells, a gas gradient would be the worst-case as this will give the highest pressure below the barrier.

For new wells, fracture closure pressure (FCP) should be used as formation integrity pressure for production wells (including P&A of these). For already existing wells, the same pressure used in the original designs can be used, as long as it is in the interval FCP to LOP [8].

The Minimum Setting Depth (MSD) is at the point where formation integrity equals that of the potential pressure below. This will be the shallowest depth for the top of the secondary barrier, meaning that the primary must be set even deeper (see Figure 3-7).

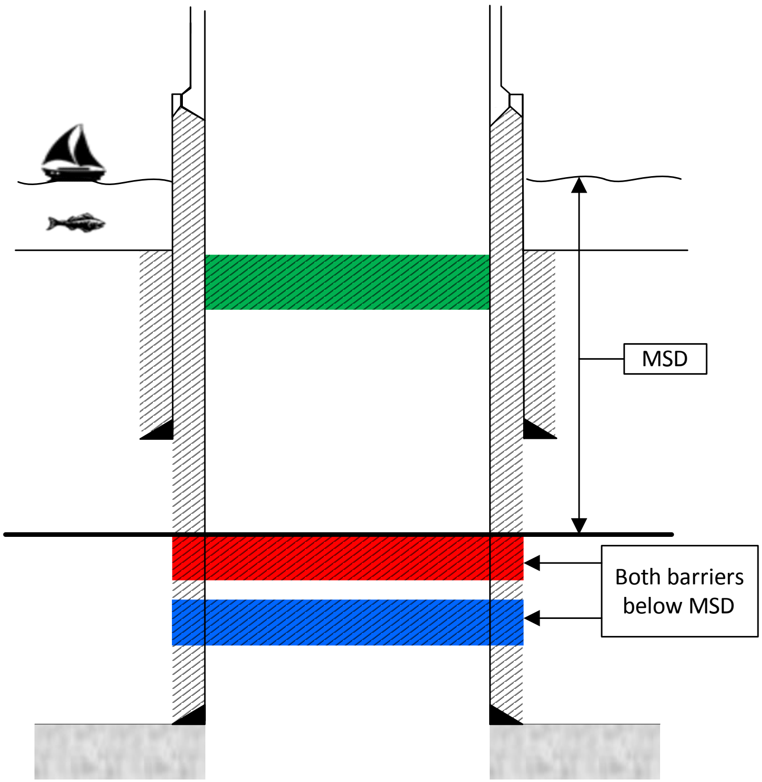

Figure 3-7: Both primary and secondary well barrier must be placed below MSD

3.4.3.3. Suitable Formation

When the MSD is found, a suitable formation should be found at this depth or below. This formation is used as a seal to prevent flow through the formation to other formation zones, or surface. NORSOK D-010 states *"The formation shall be impermeable with no flow potential."* [8].

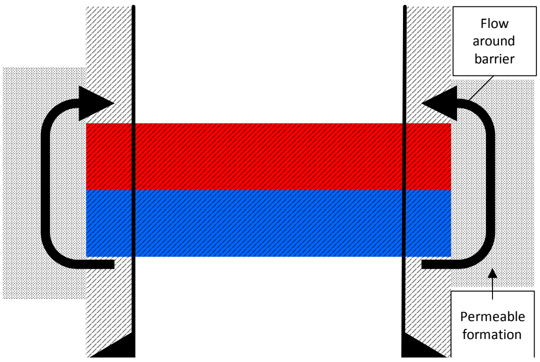

Figure 3-8: Unsuitable formation

Shale is often used as a barrier on its own (creeping formation), but also as a suitable formation. Testing performed on Pierre shale by L. E. Austebø (2016) returned a permeability between 275 – 2088 nD [2] depending on temperature [19]. Even though these numbers are very low, it is worth noting that permeability is present in shale.

[2] nD – Nano-Darcy

3.4.4. Length Requirements

NORSOK D-010 differs between internal and external WBE (see Figure 3-9), where annular cement is an external WBE, and plug set inside casing is considered an internal WBE [8]. Length requirements for these types of WBE are different. As will be shown in the coming sub-chapters, the absolute minimum length for primary and secondary barrier combined is 100 m (2 x 50m) for an internal WBE, and 60 m (2 x 30 m) for an external WBE (verified annular cement). An external WBE of materials other than cement must be minimum 100 m (2 x 50m). These lengths are in Measured Depth (MD).

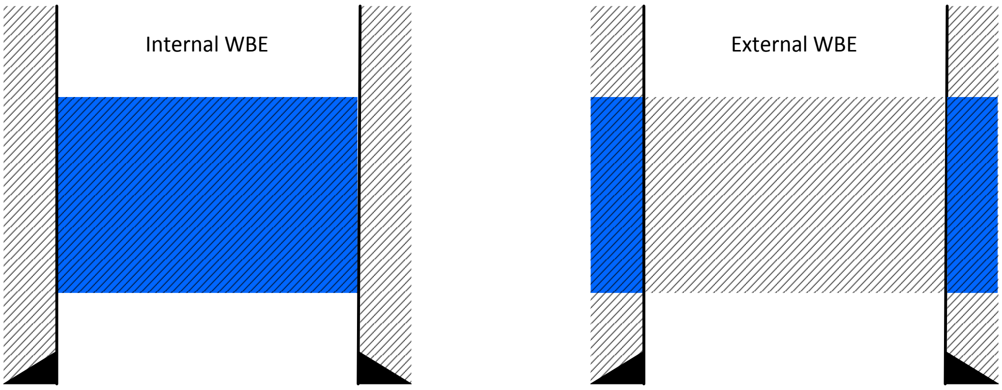

Figure 3-9: External and internal WBE

However, what is not considered for the length requirements in NORSOK, are the different conditions of the sources of inflow. The length requirements are the same for barriers covering HC reservoirs in a HPHT regime as for a hydrostatically pressured shallow zone with low temperature.

What affects the length requirements in the current standard, is whether or not it is an open hole, or cased hole; and in cases where cement is used; whether or not the quality is confirmed by logging (annular cement).

3.4.4.1. Internal WBE

It is worth noting that the length requirements for cement plugs and for plugs of other materials are given separately in NORSOK D-010 [8]. However, they are identical. Since different materials have different characteristics, it might not be the best approach to base requirements for all materials on the performance of Portland cement.

Open Hole

For an open hole plug, the length requirement is a minimum of 100 mMD, in addition to the following requirements [8]:

1) If the plug is placed in the transition between casing and open hole, there should be at least 50 mMD of plug both above and below the transition.
2) Minimum 50mMD of the plug should be placed above sources of inflow, or leakage points.

It is accepted to place the primary and secondary barrier together as one continuous plug, with double length. This is beneficial, since the strongest cement is located at the middle of the plug, where there is less contamination from e.g. well fluids and filter cake [20]. This is also the reasoning behind the two additional requirements mentioned, where we want the strongest cement in the transition zone, or across/above the leakage points/source of inflow.

Cased Hole

The requirement for a cased hole is also a minimum of 100 mMD, but it can be reduced to 50 mMD by using a mechanical foundation [8]. This ensures correct placement and less contamination than placement on a viscous pill.

If a continuous plug is to be used for the primary and secondary barrier inside a cased hole, it needs to be placed on a verified foundation (e.g. pressure tested mechanical plug).

3.4.4.2. External WBE

Since an external WBE is in direct contact with the formation, it is directly dependent on the strength of the formation (formation integrity). Therefore, the interval must have formation integrity [8]. The length requirement is 50 mMD measured from a depth with formation integrity. This can be reduced to 30 mMD, if the cement is logged and verified.

If a continuous length of cement is to be used for primary and secondary barriers, the cement is defined as critical cement, and logging becomes a requirement [8].

It is worth noting that NORSOK does not state whether the length of accepted cement needs to be continuous, or if they can be sections that has an accumulated length over a longer cement interval. Both examples in Figure 3-10 fulfills the requirements in NORSOK D-010 for logged cement.

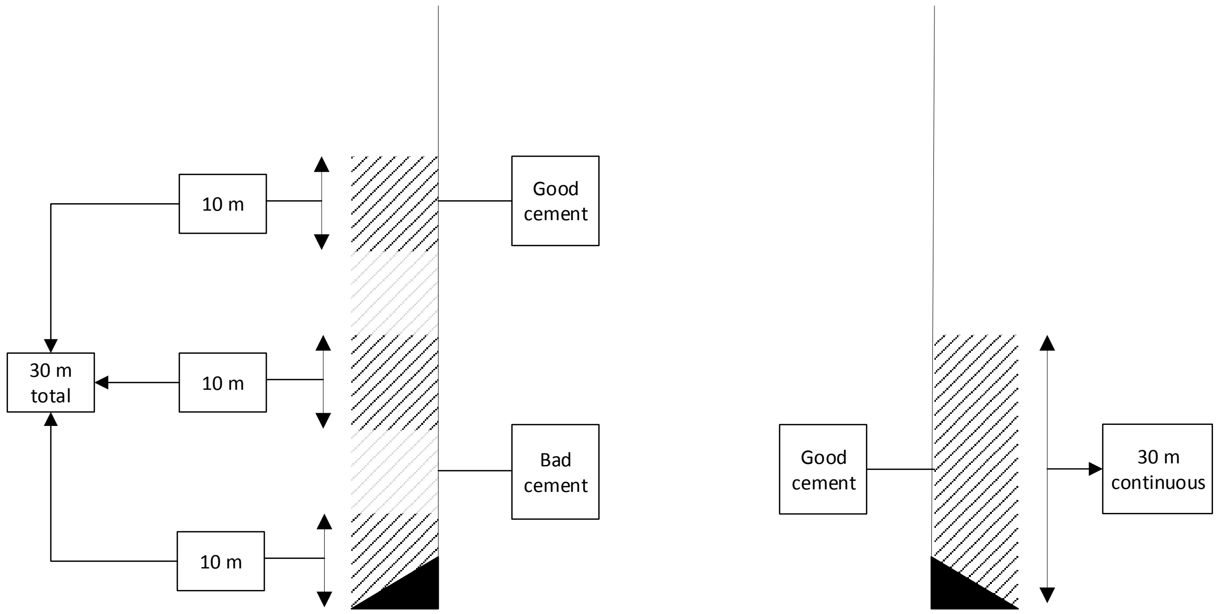

Figure 3-10: Sections of qualified cement, and continuous length of qualified cement. Both fulfill the requirements in NORSOK D-010

3.4.5. Verification of Barrier

Every WBE needs to be verified. What NORSOK requires, depends on the element and what is feasible, but the main verification method is pressure testing [8]. An important part of pressure testing is the direction of applied pressure. Because vertical stresses are normally much higher than the horizontal stresses (because of overburden), horizontal permeability is normally much higher than vertical permeability. Therefore, it is beneficial to test in the direction of flow. Alternatively, the reverse direction of flow can be used [8].

3.4.5.1. Plug Verification

Once the installation of the plug is done, the installation process should be evaluated to check for abnormalities. This can be either in placement, length and/or volumes. Once the plug has set, its placement is verified by tagging [8].

For a plug in an open hole, there is no point in pressure testing, as there is no way to tell how much has leaked into the formation (or flowed in from formation in the case of reverse pressure testing). Therefore, pressure testing is not done on open hole plugs.

Plugs in cased holes that are placed on mechanical foundations have the same problem, since it is not known what is sealed by the plug, and what is sealed by the foundation. These are not pressure tested either.

For cased holes, that are possible to pressure test, the following demands are set [8]:

- Tested at 70 bars above the estimated LOP below casing, or 35 bars for surface casing plugs.
- To ensure that the casing is not damaged during testing, the test pressure must not exceed the burst rating of the casing with wear taken into account, nor can it exceed the casing test pressure.

3.4.5.2. Verification of Casing Bonding Material

When the casing bonding material (e.g. annular cement) is set, the sealing ability and length needs to be verified.

Sealing Ability

After drilling out the casing shoe, or the casing window, a FIT test is performed, to verify that the material has sealing abilities at a given pressure [8].

Length Verification

Displacement calculations are used to confirm that the material length is above 50 mMD, where only the length above sources of inflow qualifies.

When cement is used, there is a possibility to reduce the length to 30 mMD if verified by bonding logs. This length reduction is not allowed for other materials. The use of bonding logs is mandatory when the cement is critical cement (see Chapter 3.4.4.2) [8].

3.4.6. NORSOK A-001N

According to NORSOK A-001N which contains the guidelines for development and design of NORSOK standards, the NORSOK standards need to be evaluated periodically. A revision can be suggested at any time by the owners or by the industry, but an evaluation shall take place at least every five years [21].

During this evaluation, there are four possible outcomes:

1) The standard is suggested to become an ISO standard
2) The standard is accepted as it is
3) The standard will be set up for revision
4) The standard is withdrawn

NORSOK D-010 revision 5 is expected to be released in 2018, meaning that evaluation has already taken place within the five-year deadline.

One of the main premises in the NORSOK standards, is that they shall be developed under the motto "sufficient is adequate" (Translated from Norwegian: "godt nok er godt nok") [21].

3.5. History of Length Requirement on NCS

The first regulations for P&A on NCS came in 1967 through a royal decree, and did not contain any length requirements. Length requirements were first introduced in 1975 when "Regulations for drilling for petroleum in Norwegian internal waters" was published. The minimum length for a cement plug was then set to be 30 m [18].

The length requirements were set to coincide with the regulations on the UK continental shelf, and established practice in the industry. Originally, the plug length was planned to be 300 ft (= 91.44 m). Instead, it was decided that 100 ft should be enough (=30.48 m). As ft is not commonly used in Norway, it was converted to meters and rounded off to 30 m [22]. It is this number that first appeared in the Norwegian regulations from 1975.

In the revision of these regulations that came out in 1981, the requirements became stricter, with a minimum length of 50 m for a cement plug [18].

Norwegian Regulations

Name of Regulation	Regulations for drilling for petroleum in Norwegian internal waters	Regulations for drilling etc. for petroleum in Norwegian internal waters	NORSOK D-010 Rev.4
Year / Type	1975	1981	2013
Open hole Plug	30 m	50 m	100 m
Cased hole Plug	Mechanical Foundation +15 m cement OR 30 m cement above and below casing shoe	Mechanical Foundation +20 m cement OR 50 m cement above and below casing shoe	Mechanical Foundation +50 m cement OR 100 m cement
Open hole to surface plug	150 ft (=45.72 m)	100 m	Mechanical Foundation +50 m cement OR 100 m cement

Table 3-1: History of length requirements on NCS

As can be seen from Table 3-1, there has been little consistency throughout history on what lengths are to be used. The general trend however, is an increase in required length. At the same time, technology improvements, has led to an increased control. Instead of using a fixed length requirement for all wells, an alternative approach could be to have a more flexible length requirement, which depend on the specific well conditions, the pressures involved and the quality of the cement.

3.6. Length Requirements in Other Countries

Different nations have different regulations and standards. This chapter aims to give a brief introduction into the length requirements of selected nations. When investigating this information, it was noted that the regulations referred to one another, which may explain the similarities between some of them. A summary has been given in Table 3-2.

Minimum Length per Barrier						
	NORSOK D-010	**Oil &Gas UK**	**Code of Practice Queensland (Australia)**	**Directive 020 Alberta (Canada)**	**Guidelines for Drilling Denmark**	**Texas Administrative Code (USA)**
Cement Plug	50 m	100 ft (= 30.48 m)	60 m (30 m above and 30 m below top of formation)	8 m	50 m	100 ft ** (= 30.48 m)
Annular Cement	30 m	100 ft (= 30.48 m)	Good cement adjacent to plug	Not mentioned	Not mentioned	100 ft (=30.48 m)
Comments	*MD **30m requires verification by logging	*MD	*MD	*Vm **"Sufficient" number of barriers	*MD **Single barrier	*MD **+10% for each 1000 ft depth *** Single Barrier

Table 3-2: Summary of minimum length requirements in different regulations per barrier

It is worth noting that these requirements are for cement. Most of these regulations does not consider other materials.

3.6.1. UK Guidelines

The guidelines for the UK Continental Shelf (UKCS) are called "Oil & Gas UK". Length requirements for P&A can be found in "Guidelines for the suspension and abandonment of wells" [23]. Similar to NORSOK standards, Oil & Gas UK also uses a two-barrier philosophy.

Cement Plug

For a cement plug, the requirements on the UKCS are at least 100 ft MD (=30.48 m) of "good cement". Oil & Gas UK uses the term "good cement" for cement where position, volumes and quality have been verified [23]. The regulations also state that 500 ft MD (=152.40 m) will be set when possible.

When a continuous cement plug is set for both barriers, the minimum requirement is 200 ft MD (=60.96 m) of good cement, and 800 ft MD (=243.84 m) will be set when possible [23].

Cement in Annulus

As for a cement plug, 100 ft MD (=30.48 m) of "good cement" is considered suitable for casing cement to be used as a part of the permanent barrier. However, if there is uncertainty involved in the length of cement, additional cement is placed so that generally, the total length is 1000 ft MD (=304.8 m) from the base of the primary barrier. Sources of uncertainty in this aspect can be if the length of cement is estimated by the monitoring of volumes during placement, or if Top Of Cement (TOC) is estimated by pressure differential. These 1000 ft can include both primary and secondary barrier, and the length can be increased or decreased according to the confidence in the original cementation process [23].

UK Guidelines is currently being updated to issue 6, where there will be a higher focus on risk based approach considerations [2].

3.6.2. Queensland (Australia)

Guidelines, or “Code of Practice” for Queensland is given by The Department of Natural Resources and Mines. Length requirements for P&A can be found in the code of practice called “For the construction and abandonment of petroleum wells and associated bores in Queensland”. A two-barrier philosophy is used, where cement “*shall be used as the primary sealing material*” [24].

Both for cement plugs in open hole and in cased hole, the length requirements are the same. Verified cement of 60 mMD need to be set, where 30 mMD must be above, and 30 mMD must be below the top of the zone to be isolated [24]. In addition, for cased hole, the cement plug must be placed adjacent to good cement in the annulus. No additional length requirements are given for annular cement [24].

3.6.3. Alberta (Canada)

Requirement for P&A in Alberta, Canada are found in “Directive 020: Well Abandonment” issued by The Alberta Energy Regulator [25]. In this regulation cement plugs of “*sufficient length and number*” [25] are required to be set to cover the necessary zones.

Open Hole Abandonment

The regulation from Alberta separates between open hole abandonment plugs placed shallower than 1500 mTVD (True Vertical Depth), and plugs placed deeper than 1500 mTVD [25].

For depths of less than 1500 mTVD, all plugs must be a minimum of 30 Vm (Vertical meters) (see Figure 3-11), where a minimum of 15 Vm must be below and 15 Vm above the zone covered [25]. It is worth noting that the rest of the regulations investigated used MD in their requirements, and not Vm (see Table 3-2).

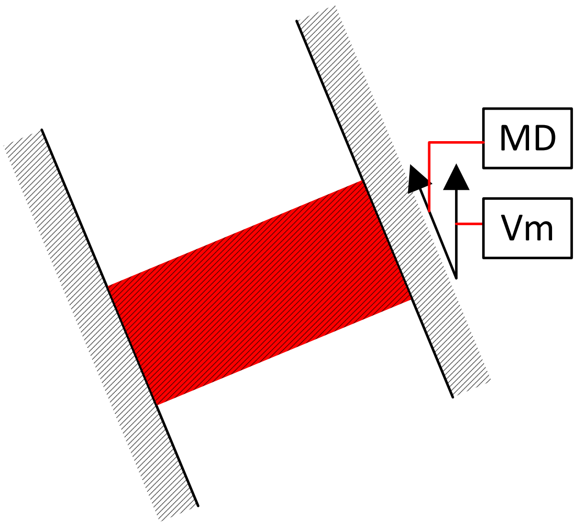

Figure 3-11: Vertical meters (Vm) vs measured depth (MD)

For depths of more than 1500 mTVD, these requirements are doubled to a minimum of 60 Vm, with 30 Vm above and below each zone [25].

Cased Hole Abandonment

For abandonment of cased holes, the requirements in Alberta depend on several aspects, where wells penetrating HC zones are of interest in this context. Further, Level-A wells (sour wells, wells used for injection of acid gas of wells used for disposal of certain fluids) will not be considered, nor will uncompleted wells.

For each zone, a bridge plug or a cement retainer is set, and capped with a minimum of 8 Vm of cement extending a minimum of 15 Vm above the top of formation (see Figure 3-12) [25].

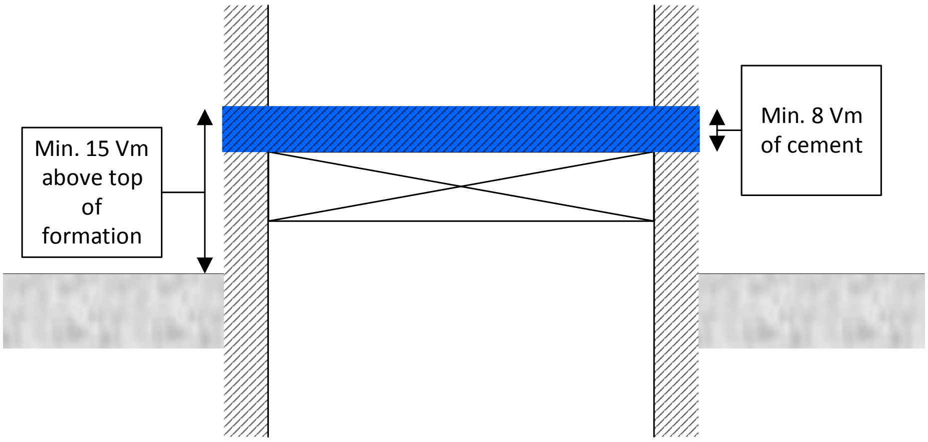

Figure 3-12: Minimum 8 Vm of cement extending a minimum of 15 Vm above the top of formation

Although cement in the annulus is not mentioned in this directive, it might be mentioned in other directives concerned with other parts of the wells life time.

3.6.4. Denmark

"Guidelines for Drilling - Exploration"[3] is published by the Danish Energy Agency. Although the guideline title suggests that it is for exploration, Chapter 11 is for abandonment of wells [26]. In these guidelines, the number of required barriers is not mentioned. However, one phrase is worth mentioning: "*When a well is abandoned the original state of the well site shall be re-established*" [26].

The guideline states that a cement plug of at least 100 m shall be placed in the top section of the well, near surface. A cement plug of at least 100 m shall also be placed in the innermost casing at the depth of the previous casing shoe and up. In open hole sections where there are permeable zones, plugging shall be done. Normally, this is done by cementing at least 50 m above and below the zone.

[3] https://www.yumpu.com/en/document/view/5344829/a-guide-to-hydrocarbon-licences-in-denmark-exploration-and- (p.267)

In cases where an open hole is found below the lowest casing string, a cement plug shall be set in such a way that the cement plug extends at least 50 m above and below the casing shoe. If the condition of the formation prevents, or makes the cementing difficult, a mechanical plug may be set within the casing, with at least 50 m of cement on top [26] .

Cement in annulus is not mentioned in this regulation, but may be mentioned in other regulations [26].

3.6.5. Texas (USA)

Regulations concerning P&A in Texas can be found in the Texas Administrative Code title 16, part 1, section 3.14 called "plugging"[4] [27]. These regulations are controlled by the Secretary of State.

In the subchapter "*General plugging requirement*" the following line can be found: "*All cement plugs, except the top plug, shall have sufficient slurry volume to fill 100 feet of hole, plus 10% for each 1,000 feet of depth from the ground surface to the bottom of the plug.*" [27].

Requirements for the length of cement in annulus is not mentioned in this section, but in section 3.13 called "*Casing, Cementing, Drilling, Well Control, and Completion Requirements*" [27] some requirements for the length of cement in annulus can be found. These are depicted in Table 3-3.

Verification method for top of cement	Minimum length (MD) [ft]	Minimum length (MD) [m]
Calculation	600 ft	182.88 m
Temperature survey	250 ft	76.2 m
Cement evaluation log	100 ft	30.48 m

Table 3-3: Length requirements for annulus cement in Texas

[4] http://txrules.elaws.us/rule/title16_chapter3

4. Portland Cement

Portland cement is the most commonly used plugging material, both because it is considered the most reliable and best plugging material, but also since it is easily available worldwide and because it is cost-effective [9] [28].

Cement consists of reactive oxides, where Calcium Oxide is the main ingredient. There are different sources available for Calcium Oxide over the world, where the most common ones are chalk, shale, calcite, marl and limestone [28].

To manufacture cement, the raw materials are pulverized and mixed, before the mixture is heated up to temperatures as high as 1550 °C, and then cooled in a controlled manner [28]. Exiting this process is a product called "clinker". By pulverizing the clinkers with gypsum, Portland cement is obtained. During the heating process all water in the mixture has evaporated, meaning that the clinkers are anhydrous.

By adding water, hydration starts, and it is this process that causes the cement to set [28].

Portland cement is divided into 8 classes (A through H) by the American petroleum institute, where class G is the most commonly used in offshore wells [9] [29]. The classes are classified from strength in the following areas:

- Temperature resistance
- Pressure resistance
- Sulphate resistance
- Placement depth

4.1.1. Additives

Since every application of Portland cement is different, there might be need for different types of additives to achieve the necessary properties. According to Nelson and Guillot there are eight categories of additives [28]:

1) Accelerators – Decreases setting time of the cement
2) Retarders – Increases setting time of the cement
3) Extenders – Decreases the density of the cement
4) Weighing materials – Increases the density of the cement
5) Dispersants – Reduces the viscosity of the cement
6) Fluid-loss controlling agents – Prevents fluid loss from the cement
7) Lost-circulation controlling agents – Prevents loss of cement slurry to formations
8) Specialty additives – Miscellaneous additives (e.g. antifoaming agents)

For cement needing a high degree of fluid-loss control, such as cement used to seal of gas prone reservoirs, fluid-loss controlling additives can be used, as they have good gas hindering effect [28]. This will effectively reduce the permeability of the cement.

4.1.2. Placement Techniques

There are several methods for placing Portland cement depending whether the cement is to be placed in the annulus, or in the wellbore, and if it is primary cementing or remedial cementing. Some techniques will be presented in the following chapters.

4.1.2.1. Internal Cement Placement Techniques

For the internal WBE (see Chapter 3.4.4.1) a cement plug is normally set on top of a mechanical plug, or on top of a viscous pill if set in an open hole. This is done to prevent the cement slurry from sliding further into the hole, losing control over contamination and placement. To obtain as little contamination of the cement as possible, and to ensure the correct volumes are used, there are several techniques available depending on the conditions and volumes.

Balanced Plug

Balanced plug cementing is a common method for placement of cement plugs (see Figure 4-1). To ensure proper cementing, the hole needs to be cleaned thoroughly before cementing to avoid permeable channels, and to prevent a mud cake from hindering bonding to formation [28]. This may be achieved through additional circulation. To separate the cement slurry from the well fluids, a spacer fluid is pumped ahead and behind the cement slurry. This is important, since cement contamination is the main problem for this placement technique [30]. Usually, the spacer is a water based fluid, treated and designed to separate mud from cement slurry [10].

Directly after the first spacer fluid, the cement slurry is pumped into the hole until the cement levels in the annulus and drill pipe are balanced. The drill pipe is then pulled out slowly to ensure balanced levels, and to prevent contamination of cement [28].

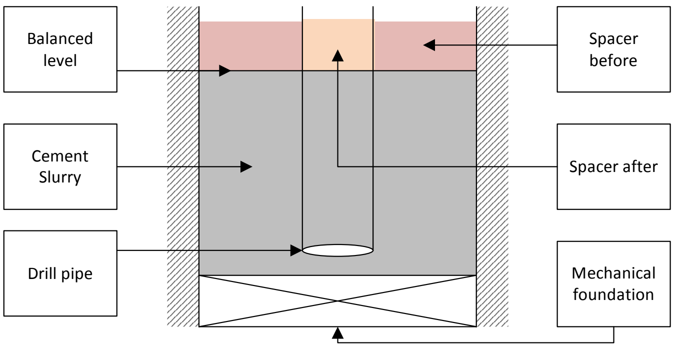

Figure 4-1: Balanced plug cementing

Dump Bailer

A container (bailer) attached to a WL or slickline containing cement slurry is lowered into the well. When it reaches the cement setting depth, it is either tagged against a mechanical plug, or opened electronically. When the bailer is opened, the cement slurry is let out into the well.

In contrast to cementing through coiled tubing or drill pipe, the volumes are severely limited due to the size of the bailer. In addition, there is no way to aid the cement slurry out of the bailer, so an additive to delay gel-strength is often added to the slurry to ensure that all the slurry flows out. However, the risk of contamination is reduced with the use of this method [9].

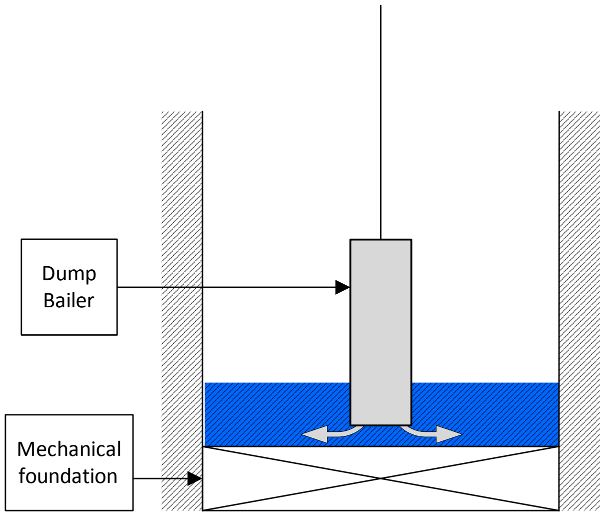

Figure 4-2: Dump bailer cementing

4.1.2.2. Annulus Cement Placement Techniques

When annular cement is placed with casing (primary cementing), the two-plug method may be used. However, if cement needs to be placed in the annulus at a later stage, the operation becomes far more complex. If the wells were designed to be P&A before being drilled, some of these operations would be unnecessary (e.g. lack of cement behind casing and lack of cement logging).

Two-Plug Method

When performing primary cementing with the two-plug method (see Figure 4-3) or single stage cementing as it also called, a wiper plug (bottom plug) is pumped down the casing pipe to separate the cement slurry from the well fluids, and to wipe of casing walls. The first wiper plug has a membrane that ruptures when it lands at the bottom of the casing [31]. The cement slurry is added on top of the bottom plug, until a predetermined volume is reached. When all the cement is added to the casing, a top plug is added. Unlike the bottom plug, the top plug does not have a membrane, and when it lands on top of the bottom plug, it does not rupture, and the cementing is stopped to let the cement set [31].

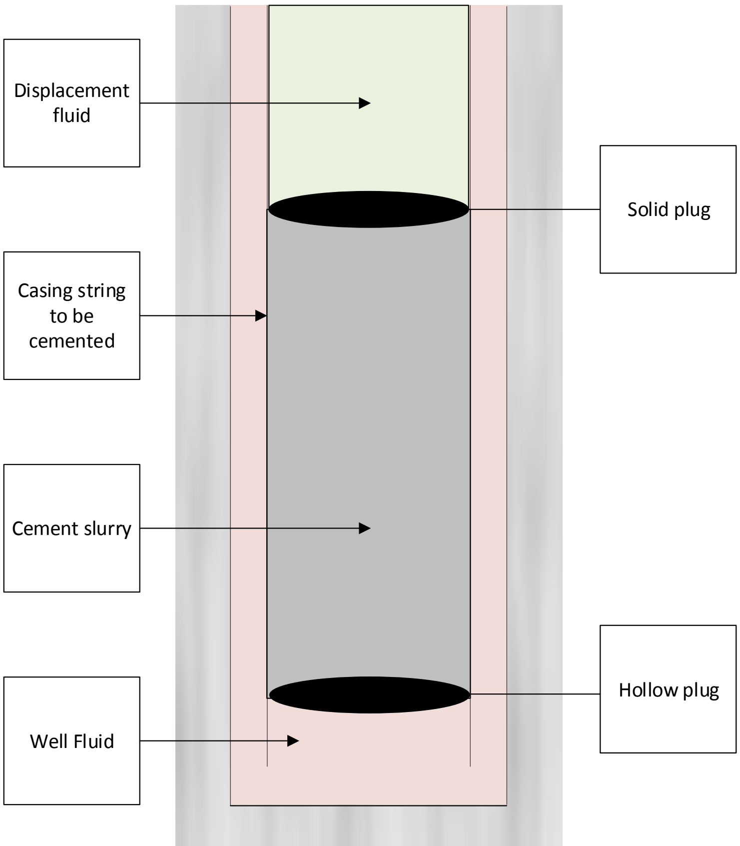

Figure 4-3: Two-plug method for primary cementing

Squeeze Cementing

If there are known permeable channels between the casing and the formation (e.g. insufficient filter cake removal), squeeze cementing may be used. NORSOK D-010 also accepts it to be used if the interval of the verified annular cement is not long enough (see Chapter 3.4.4.2) [8].

By squeezing cement through perforations or holes into the voids and formation, a good bond to the formation is ensured. Squeeze cementing can be done either through low pressure squeeze, where the pressure is lower than the formation fracture pressure, or through high pressure squeeze, where the pressure is above the formation fracture pressure [28]. Since the cement is forced into the formation, the size of the particles must be smaller than ordinary cement to avoid being filtered out against the formation [28].

Within the range of high and low pressure squeeze cementing, there are two techniques (Bradenhead and squeeze-tool technique), and two pumping methods (running squeeze and hesitation squeeze) [28].

With the use of Bradenhead, no packer is used from the squeeze interval and up, so the pressures will be applied along the whole casing and on the WH. If there is doubt on the casing/WH ability to withstand the pressure, the squeeze zone is isolated (Squeeze-tool technique) [28].

The pumping method used is largely dependent on the volumes. For larger cement volumes, the running squeeze pumping method may be used, where cement slurry is pumped continuously until the squeeze pressure is reached. The pressure is then kept constant. For smaller volumes, it may not be possible to maintain constant pressure as the pumps will add to much volume. Then the pressure is applied periodically through the hesitation squeeze pumping method [28].

PWC

PWC or Perforate, Wash and Cement is a relatively new technique that is designed to cement poorly cemented or uncemented sections behind the casing. The PWC process is divided into three stages, namely perforate, wash and cement [32].

When the PWC tool was first designed, it was intended to perform the process with three separate trips, but the tool was later improved so that the whole process could be done in a single trip [32]. Since the time used to trip in and out of a well can be extensive, saving trips saves time.

First the tool is lowered to the desired depth, where the perforation guns are set off to perforate the casing [9]. After the perforation gun has been fired, it is disconnected and left in the well, thus requiring a free interval of at least the same length as the perforation gun [32]. If this is not available, the perforation must be done on a separate trip, so the perforation gun can be retrieved.

Above the perforation gun, a washing tool is found. This can be either cup based of jet based [32]. The tool is moved up and down while the cleaning fluid is circulated with a high velocity through the perforations, which are used as nozzles [33].

4.1.3. Factors Affecting Portland Cement

There are several aspects that have a negative effect on Portland cement as a barrier element. Some of the main aspects are:

1. Chemical degradation by the fluids and gases in contact with it (see Chapter 4.1.3.1).
2. Cement Shrinkage (see Chapter 4.1.4).
3. Degradation caused by thermal cycling during the lifetime (see Chapter 4.1.3.2).
4. Water ratio in cement (see Chapter 4.1.5).
5. Poor mud displacement before cementing (see Chapter 4.1.6).

4.1.3.1. Chemical degradation

One of the characteristics that a well barrier should have, is to be chemically resistant to H_2S, CO_2 and HC (see Chapter 3.4.2).

Effect of H_2S on cement:

In addition to being a deadly gas for humans even in small concentrations, H_2S will also leach calcium from the cement matrix [34]. A. Garnier et al. (2012) performed some testing on class G Portland cement with H_2S, where leaching reached as high as 43% in three months [34]. Although these tests were performed with a higher H_2S concentration than what is typically found in the North Sea, it shows that cement degradation by H_2S should be taken seriously. Since an eternity perspective should be considered for P&A, the timescale is very different from a laboratory test.

Effect of CO_2 on cement:
The effect of CO_2 on Portland cement is a well-researched phenomenon that can be shown through a five-step cycle [28]:

1) Carbon dioxide (CO_2) reacts with water (H_2O) to form carbonic acid (H_2CO_3).

$$CO_2 + H_2O \rightleftharpoons H_2CO_3 \rightleftharpoons H^+ + HCO_3^-$$

2) The sour water penetrates and spreads into the cement matrix, and reacts with free calcium hydroxide ($Ca(OH)_2$), forming calcium carbonate ($CaCO_3$).

$$H^+ + HCO_3^- + Ca(OH)_2 \rightarrow CaCO_3 + 2H_20$$

3) The sour water also reacts with lime (CaO) and silica ($Si0_2$), forming more calcium carbonate ($CaCO_3$).

$$H^+ + HCO_3^- + CaO + Si0_2 + H_20 \rightarrow CaCO_3 + \text{amorphous silica gel}$$

4) Water (H_2O), carbon dioxide (CO_2) and calcium carbonate ($CaCO_3$) then reacts into calcium bicarbonate ($Ca(HCO_3)_2$), which is water soluble. This water may then take the dissolved products from the cement out of the cement matrix.

$$CO_2 + H_2O + CaCO_3 \rightarrow Ca(HCO_3)_2$$

5) Once the dissolved cement is on the outside of the matrix, it can react with calcium hydroxide ($Ca(OH)_2$) forming calcium carbonate ($CaCO_3$) which is in solid form, and water (H_2O).

$$Ca(HCO_3)_2 + Ca(OH)_2 \rightleftharpoons 2CaCO_3 + H_2O$$

Both the water (H_2O), and the calcium carbonate ($CaCO_3$) is then free to repeat the process over again, dissolving more and more of the cement body.

4.1.3.2. Thermal Cycles

During the lifetime of a well there will be many thermal cycles as production is stopped and started again. One example is one of the wells at Valhall DP that is still in production. While this well produces, water build-up in the well will after some time stop the production as the hydrostatic pressure will stop flow. When shut in, gas enters the well from the reservoir, leading to a decrease in the hydrostatic pressure, making it possible to start production again [35].

During production the temperature will be controlled by the flowing reservoir fluid (Valhall reservoir temperature was originally 190°F (≈ 88 °C) [36]), while during shut-in, the temperature will be controlled by the geothermal temperature. The temperature changes will be worst at shallower depths, as the difference between reservoir temperature and geothermal temperature will be largest here.

As formation, steel and cement is heated, they will all expand if allowed, while they will all contract as temperature goes down [28]. Both expansion and contraction will affect the stresses in the well and therefore the annular cement sheath. As a result, the cement sheath could potentially be damaged, or a micro-annulus could be created, leading to a loss of zonal isolation [28].

4.1.4. Shrinking

As mentioned in Chapter 3.4.2, Portland cement shrinks as it sets. Le Châtelier showed that the volumetric shrinkage of Portland cement is 4.6% [28]. This is because the density of the cured cement is higher than that of the individual additives. However, this shrinkage is mostly in the internal matrix, forming porosity, whilst only 1 % is external contraction of the cement body [28].

These two types of shrinkage will lead to different failures. When shrinkage in the cement body occurs, this will result in stresses. These stresses may cause cracks in the cement. The shrinkage of the external body may cause de-bonding between the cement and the casing/formation, and thus causing micro-annuli. However, cement shrinkage can be addressed through the addition of expanding agents to the cement.

4.1.5. Water Ratio and Density

The amount of water in the cement mix, affects how easily it is to place, therefore high water concentrations are often used. However, the quality of the cement is also affected by this through lower compressible strength, lower tensile strength and higher permeability through the matrix [37].

Normally, the permeability for a cement of normal density after setting, is in the micro Darcy range.
If instead, the system is of low density cement, with high water concentration, the permeability might be much higher. According to Nelson and Guillot, a range of 0.5 – 5.0 mD might be expected [28].

Testing of cement performed by Coleman and Corrigan [38] with high water-cement ratio, showed that in water-rich cements, the particles settled, causing the water content to be higher at the top of the cement, than at the bottom. This lead to higher permeability at the top of the cement, than at the bottom [38]. The average permeability for the top of these 12" (= 0.3048 m) high samples 72 hours after placement, were over three times higher than those measured on the bottom [38]. As cement in wells are of a considerable length, this effect may be substantial.

4.1.5.1. Lead and Tail Cement

Both to decrease cost, and Equivalent Circulating Density (ECD) (in order to prevent fracturing because of excess hydrostatic pressure) when cementing, a low-density cement may be pumped ahead (lead cement). This cement is weaker than the heavier tail cement, both due to its structure and due to increased contamination during pumping [28] [20].

The heavier cement is normally found at critical placements (e.g. casing shoe, transitional zones) where the main objective of the cement job is located (see Figure 4-4). However, the lead cement can be found as part of a barrier in a well (e.g. in shallow zones).

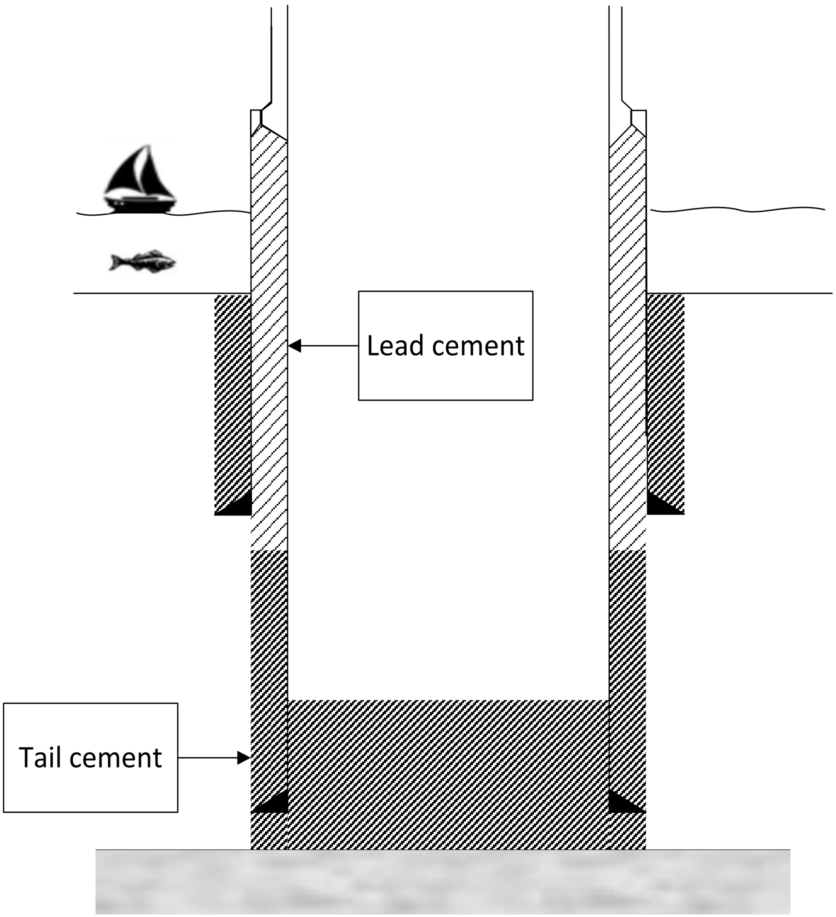

Figure 4-4: Lead and Tail cement

4.1.5.2. Cement Density vs Placement

In a typical well, high-density cement with gas hindering additives is set close to the reservoir (e.g. 15.8 ppg), while lower-density cement is set higher in the overburden (e.g. 13 ppg) [39] [28]. This reduction in density will not only affect the strength of the cement, but also the permeability as higher density cement contains more particles [28]. This makes it difficult to compare cement from one depth to another, and undermines the effect of the fixed length requirements.

4.1.6. Poor Mud Displacement

When cementing, the mud should be displaced completely as mud affects the cement negatively in several ways: 1) Mud contamination into the cement affects the mechanical properties of the cement, 2) mud layers left on the formation weakens the bonding and may cause channels [28].

In addition, poor mud displacement may also lead to voids in the cement body, and as drilling mud is not designed to be displaced, displacing it is a challenge. Research done by H. J. Skadsem at IRIS shows that displacement is especially difficult in eccentric geometries (see Figure 4-5), where channels with un-displaced fluid forms. He also shows that irregular geometry due to e.g. washout sections, would greatly affect the displacement of mud [40]. As ordinary wells do not have a uniform geometry, these are some of the problems that will occur during cementing.


Figure 4-5: Sandwich-joint retrieved from well showing eccentric casing strings [41]

5. Valhall

Valhall is an oil giant located in the North-Sea. It was discovered in 1975, and has been produced since 1982. In the beginning there were three installations at the sight; one for living quarters (Valhall QP), one for processing (Valhall PCP) and one for drilling [42]. The last of these installations is named Valhall Drilling Platform, or Valhall DP.

Production of the reservoir without pressure support for many years, has led to a compaction in the crest of more than 10 m, and a subsidence at seabed of 6.7 m [43] [36]. Due to this subsidence, the air gap between the sea level and the platforms is no longer large enough to withstand a hundred-year wave. This in combination with a planned redevelopment of the field has led to the planned replacement of Valhall DP, and causing the need for the 31 wells connected to Valhall DP to be permanently plugged and abandoned [43].

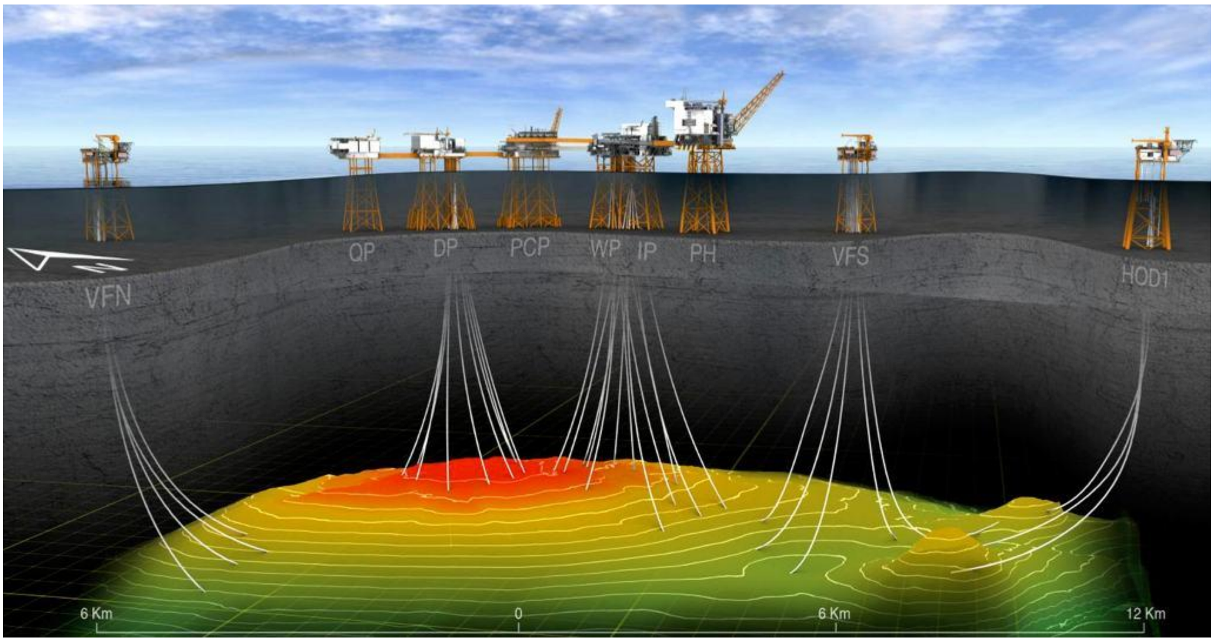

Figure 5-1: Valhall [44]

5.1. Resources at Valhall

In the first Plan for Development and Operations (PDO), the recoverable reserves were estimated to be in the order of 247 million barrels of oil, a number that was significantly lower than reality would turn out to be [45][5] [46]. By the end of 2016, around 924 million Barrels of Oil Equivalent (BOE) had been recovered, and estimated recovery from 2017 to 2049 are in the order of additional 450 million BOE. At that stage, the total recovery factor is forecasted to be at 52%, meaning that 48% will still be in place [46].

The main reason for the underestimation of the recoverable reserves is the compaction drive, which stands for over half of the recovery [46].

[5] http://www.norskolje.museum.no/forside/kunnskap/publikasjoner/arbok/norsk-oljemuseums-aarbok-2015/

5.2. Challenges at Valhall DP

Valhall is a field with a very complex overburden. The P&A project on Valhall DP has been referred to as "*One of the biggest P&A project within the BP group for a decade*" [47]. The combination of complexity and size results in a significant cost, but also a large potential for cost saving for Aker BP and the Norwegian community.

5.2.1. Sources of Inflow

In NORSOK D-010, the illustrations covering sources of inflow shows one such source [8], while the reality is much more complex. At Valhall there are 9 zones defined as Distinct Permeable Zones (DPZ); Aker BP's equivalent to source of inflow [44]. Normally a single barrier can be set between formations (cross-flow barrier), where the next barrier work as a secondary barrier for barrier below. However, the formation at Valhall is not strong enough, so that both a primary and secondary barrier will need to be set for each of the barrier locations. If each of the DPZ are to be isolated separately, one would end up with 19 barriers in each well (9 primary, 9 secondary and one environmental barrier). However, it has been found that some zones do not need a separate set of barriers (e.g. DPZ #2,3,4 and 5 can be sealed off with a single set of barriers in seal #2).

5.2.2. Short Interval Between Sources of Inflow

In order to place a primary and secondary barrier to seal off a source of inflow in accordance to NORSOK D-010, a minimum of 2x30 meters of logged and verified annular cement is needed. In some of the sources of inflow at Valhall, the length of suitable formation between them is too small to fulfill this requirement (see Figure 5-2). These DPZ are isolated with a set of barriers in seal #2.

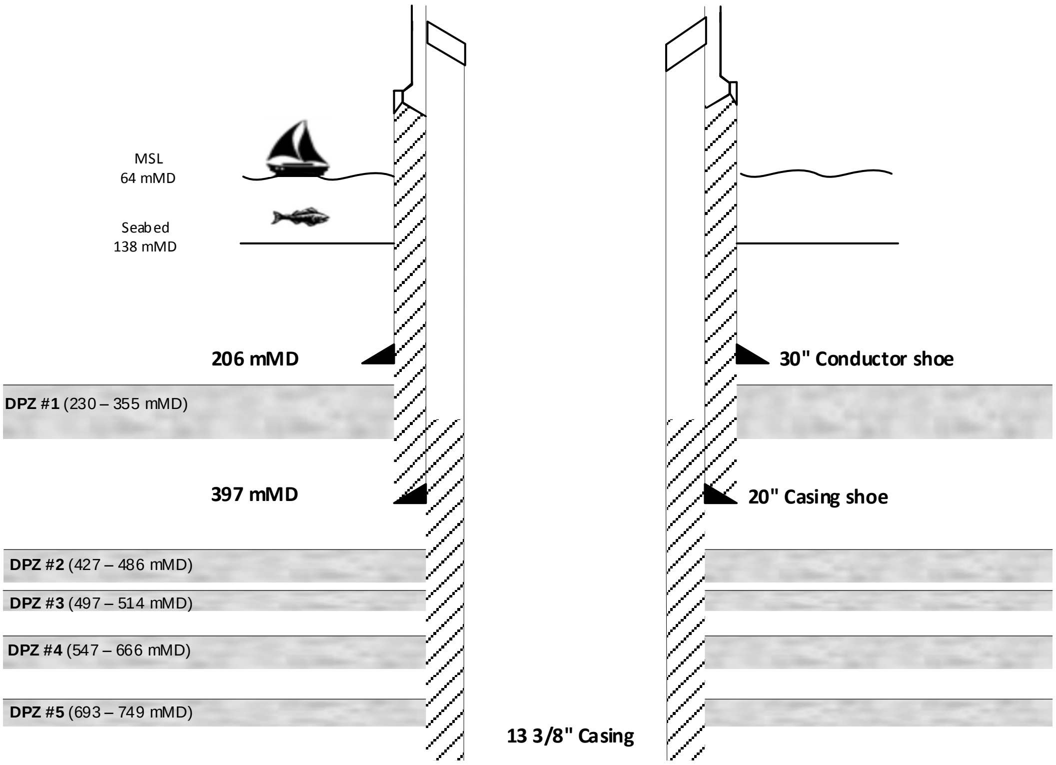

Figure 5-2: Different DPZ at Valhall

5.2.3. Seal #2

Above DPZ #2, an interval of suitable ("impermeable") formation is found. This formation acts as a cap rock (seal) for the underlying sources of inflow (DPZ #2-#5). DPZ #2-#5 is typically cased off by the 13 3/8" intermediate casing. The shoe of the previous casing (20"), is typically found in the middle of seal #2.

Figure 5-3 shows a schematic from one of the wells from Valhall DP, where seal #2 has a height of 73 mMD [48]. Within this seal, both a primary and secondary barrier are to be set. Since the cement behind the 20" casing cannot be verified through logging without removing the 13 3/8" casing, the remaining available seal is found between the 20" casing shoe and the top of DPZ #2. The length of this interval varies, but is typically in the range of 20-35 mMD (30mMD for the well in Figure 5-3). These lengths are not long enough for a double barrier according to the requirements of NORSOK D-010 [8].

Cement Bond Log (CBL) at these depths typically shows a good circumferential bond from the 20" casing shoe and down to the top of DPZ #2, and poor bond quality for the cement inside the 20" casing. Normally, the available option would be to section mill or cut and pull the 13 3/8" casing at the 20" casing shoe, log and verify the 20" casing cement, and place an accepted length of cement. However, there is a high risk of breaking down the 20" casing shoe when performing this operation, and as the 20" casing shoes from the different wells are close to each other, fractures might be created, leading flow from one well to another, or to surface. Therefore, the real interval available is the 20-35 mMD from the 20" casing shoe and down to the top of DPZ #2.

DPZ #2 is hydrostatically pressured sandstone found at shallow depths. The conditions are in the Low Pressure, Low Temperature (LPLT) range, with very limited capability to flow. Still, NORSOK D-010 has the same requirements for this zone as they have for both the reservoir found at 2400 – 2700 mTVD, and for the HPHT reservoir considered in the study of Godøy et al. (see Chapter 6.2) [8] [1] [45].

To minimize the risks when plugging and abandoning these wells, it is desirable to see if the available verifiable interval of cement is sufficient/adequate.

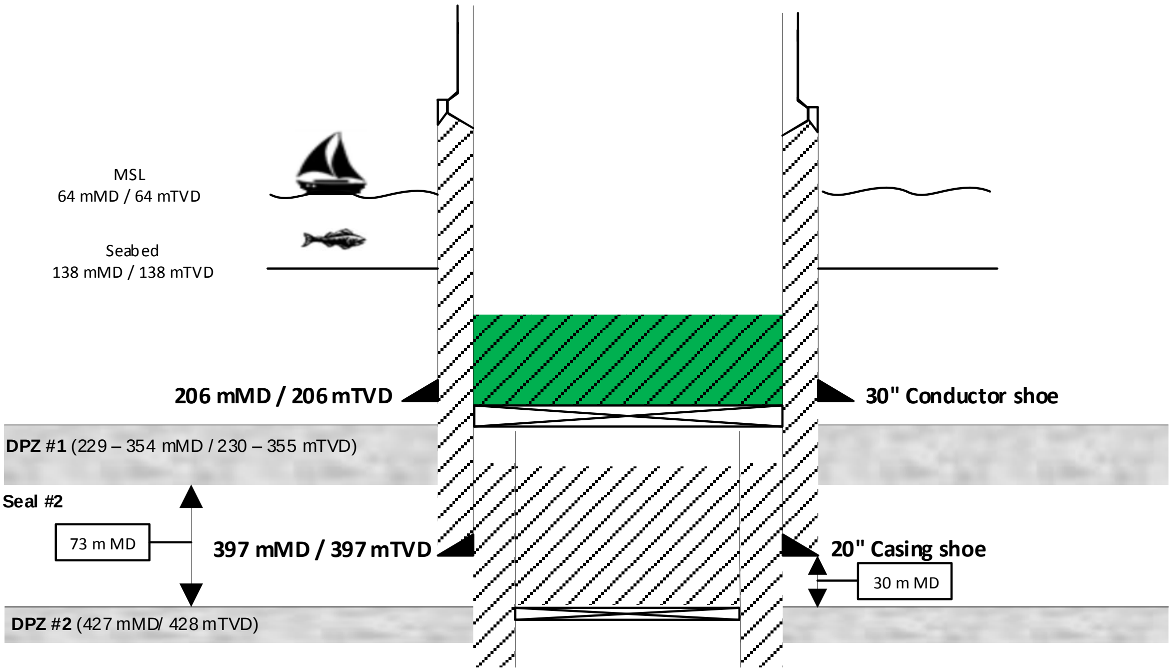

Figure 5-3: Short window for placement of barriers at Valhall DP

As mentioned in Chapter 4.1.5.1, lead cement does not have the same properties as tail cement. According to cement logs for the well in Figure 5-3, the tail cement reaches 200 mMD from the casing shoe and up for both the 13 3/8" casing, and the 20" casing. This means that in Seal #2, the 20" casing cement is high density tail cement, while the 13 3/8" casing cement is typically low density lead cement [39]. There are some exceptions, as for some of the wells, a top down squeeze of high density tail cement has been performed.

5.2.4. Subsidence

In addition to being one of the reasons behind the redevelopment of the field, the significant subsidence at Valhall is one of the main challenges at the field. In several of the wells at Valhall, there are problems with access to the wells as the subsidence has caused shifting in the overburden, and thus deformation of the tubulars (see Figure 5-5). Further, the shifting may also be a source of damage on the cement integrity as cement is a brittle material. Figure 5-4 shows the measured and expected subsidence at Valhall.

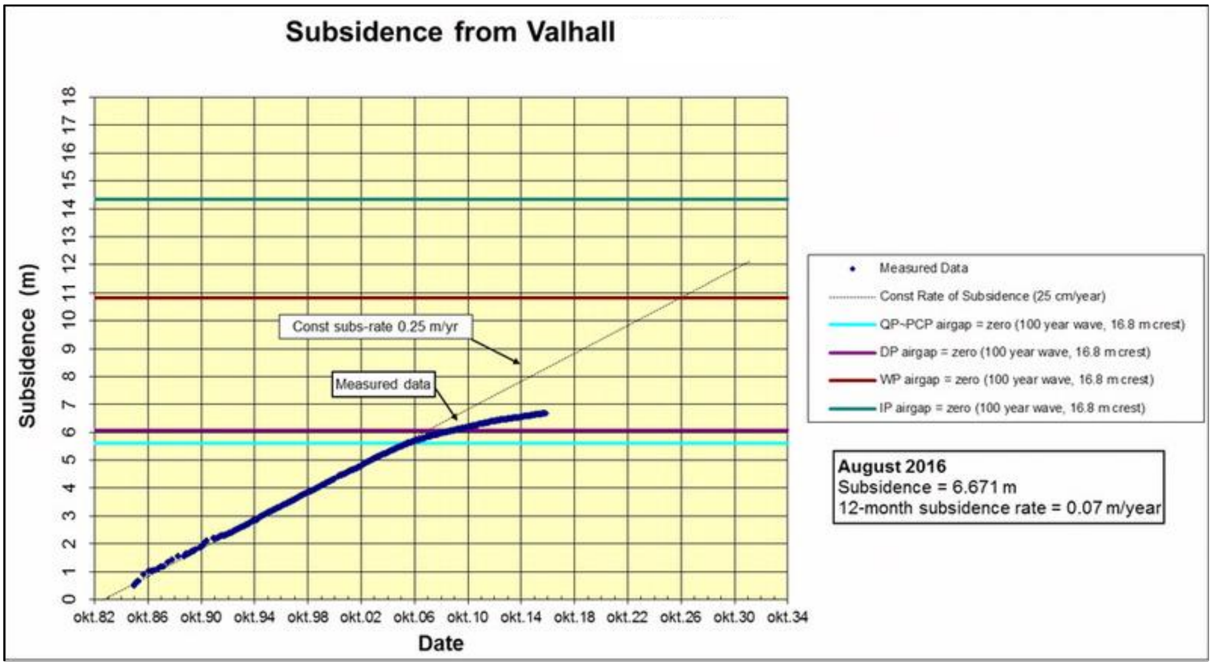

Figure 5-4: Subsidence at Valhall [49].

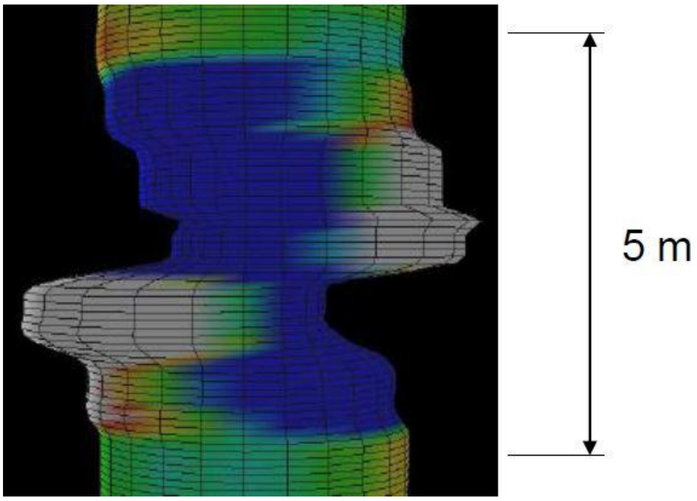

Figure 5-5: Partial collapse in one of the wells at Valhall [50]

6. Risk Based Approach

As can be seen in Chapter 3.4, the barrier lengths requirements in NORSOK D-010 are based upon a "one model fits all" philosophy. This means that the same requirements are imposed for every well. It is quite intuitive that the dangers with a HPHT well with high flow potential are much higher than a LPLT well with limited flow potential. Even so, the requirements for length of cement used in these wells are equal in NORSOK D-010. A better approach may be to match the risk with the appropriate mitigating solution.

6.1. Risk

There are several definitions of risk, all depending on the source. Three of the more relevant sources in this context, and their definitions are:

PSA[6] – "*Risk means the consequences of the activities, with associated uncertainty.*" [51]
NORSOK – "*Combination of the probability of occurrence of harm and the severity of that harm*" [52]
UK Oil & Gas – "*The combined probability and consequences of a failure mode occurring*." [53]

In the context of this thesis, consequence pertains to the rate of hydrocarbon leakage.

6.2. Risk Based Approach to Cement Lengths

A study performed by Godøy et al. [1], used a risk based approach to determine required cement barrier lengths. By looking at leakage rates through reservoir cement from a well fulfilling NORSOK D-010, a reference case was set defining an upper acceptable limit for leakage rates. The reference case was then compared to other wells. This comparison could then be used to 1) justify a reduced cement length, or 2) estimate the relevant cement length for a given cement quality. The method has already been used as a basis for dispensation approvals by operators [1].

For calculation of the leakage rates in this study, Simeo WellCem by Oxand has been used. This software is based on Darcy's law, with the use of an effective permeability (see Chapter 7.2). An HPHT well from the well portfolio of an operating company on the NCS fulfilling NORSOK D-010 criterions were chosen as the reference well [1] [54]. In this well, the most likely cement gas permeability was estimated to 0.5 µD, and a gas permeability of 0.1 µD was used (best cement for reference case will lead to worst-case scenario for comparison). The cumulated verified annular cement length equals 30 m (one barrier), with a pressure difference across the cement of 470 bars. The resulting leakage gained from Simeo WellCem was 0.98 kg/year for one-phase gas modeling [1] [54]. This case is set as an "*Upper Accepted Case*" (UAC) [1]. By calculating the leakage through a barrier in another well, it can be compared to the UAC. If the leakage is lower than the UAC for the planned design, it is documented as better, and could thereby be accepted according to the risk based approach. Alternatively, the reference case can be used to plan the cement length necessary to achieve a documented level of acceptance.

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[6] http://www.psa.no/framework/category408.html#p11

It is worth noting that in this study, only gas mass flow rate is studied. When using the one-phase gas model, a dry cement is assumed, while the cement will be saturated with liquid in a well [55].

This is the study that forms the background for this thesis, and the reader is urged to read it in full[7].

[7] SPE-177612-MS titled "well Integrity Support by Extended Cement Evaluation – Numerical Modeling of Primary Cement Jobs" by R. Godøy et al. [1]

7. Leakage

Leaks in the subsurface will happen through man-made barriers, but it also happens through nature's own barriers (i.e. cap rock). From the crest of the Valhall reservoir, there is a significant HC leakage into the overburden [36]. This leakage charges DPZ #7, where it is trapped and prevented from reaching surface. However, there are many places in the world where active seepage from the underground can be found at surface. Only 30 km North-West from Valhall, a prominent seepage area can be found, i.e. Tommeliten. Scheider von Deimling et al. did research in the Tommeliten area, and estimated a yearly release in the order of 26 tons methane [56]. Approximately 16 km West from Valhall, the border between the UKCS and NCS can be found. UK Oil & Gas has estimated the total natural seepage of methane on the UKCS to be in the order of 120 000 – 3.5 million tons per year [53].

The leakage rates through cement barriers can be estimated, and both IRIS[8] (International Research Institute of Stavanger) and Oxand[9] among others have software's designed for this purpose. Both single-phase flow and bi-phasic flow can be assessed. In the IRIS leakage calculator, the leakage is split into different leakage pathways reflecting that leakage can occur in several ways, whereas the Simeo WellCem leakage calculator uses an effective permeability.

For this study, only Oxand's Simeo WellCem has been used. IRIS leakage calculator is in development and for future work, one should consider using this and similar software's. The use of several different models can strengthen the theoretical foundation for the proposed methodology in the same manner as different weather forecast models are used. Though it will not be used, the functionality of the IRIS leakage calculator is described, as the calculator will be a good tool for further qualification of the method.

7.1. IRIS Leakage Calculator

Fatemeh Moeinikia et al. has described the IRIS leakage calculator in SPE paper *SPE-185890-PA* "*Leakage Calculator for Plugged-and-Abandoned Wells*" [37]. This leakage calculator estimates leakage through a permanent barrier system with failure. Both deterministic inputs and uncertain inputs represented by probabilistic distributions are considered. The leakage rates are therefore estimated statistically as probability and cumulative distributions. In the IRIS leakage calculator, three leakage paths are currently included [37]:

1. Through bulk cement (see Chapter 7.1.1)
2. Cracks/fractures (see Chapter 7.1.2)
3. Micro annuli (see Chapter 7.1.3)

7.1.1. Through Bulk Cement

Cement is a porous media with permeability, even though it is often looked upon as impermeable. Since it has permeability, flow can/will occur through it due to pressure differences across the cement. In the IRIS leakage calculator, flow through bulk cement is estimated using Darcy's law [37].

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[8] http://www.iris.no/home

[9] http://www.Oxand.com/

$$Q = \left(\frac{k\ A}{\mu\ L}\right)(\Delta P - \ \rho\ g\ L\ cos\theta)$$

Where:

Q – Flowrate $[\frac{\mathrm{m}^3}{\mathrm{s}}]$

k – Permeability $[\mathrm{m}^2]$

A – Cross sectional area $[\mathrm{m}^2]$

µ – Viscosity of fluid [Pa s]

L – Length of cement [m]

ΔP – Pressure difference across cement [Pa]

ρ – Fluid density $[\frac{\mathrm{kg}}{\mathrm{m}^3}]$

θ – Well inclination from vertical [◦]

7.1.2. Cracks/Fractures

Cracks in the cement body can be formed both by tectonic stresses (e.g. movement), and shrinkage of the cement (see Chapter 4.1.4). These cracks may form channels [37]. In the IRIS leakage calculator, the following equation is used for estimation of leakage through cracks:

$$Q = \left(\frac{h^3\ cos\ \alpha}{12\ \mu}\right)\left(\frac{\Delta P}{L}\right)\ W$$

Where:

h – Fracture aperture [m]

α – Fracture orientation (angle between the direction of the pressure gradient and the fracture orientation) [°]

W – Fracture width [m]

As knowledge of fracture aperture, fracture orientation and fracture width (see Figure 7-1) is normally unknown information, they are considered uncertain in the calculator.

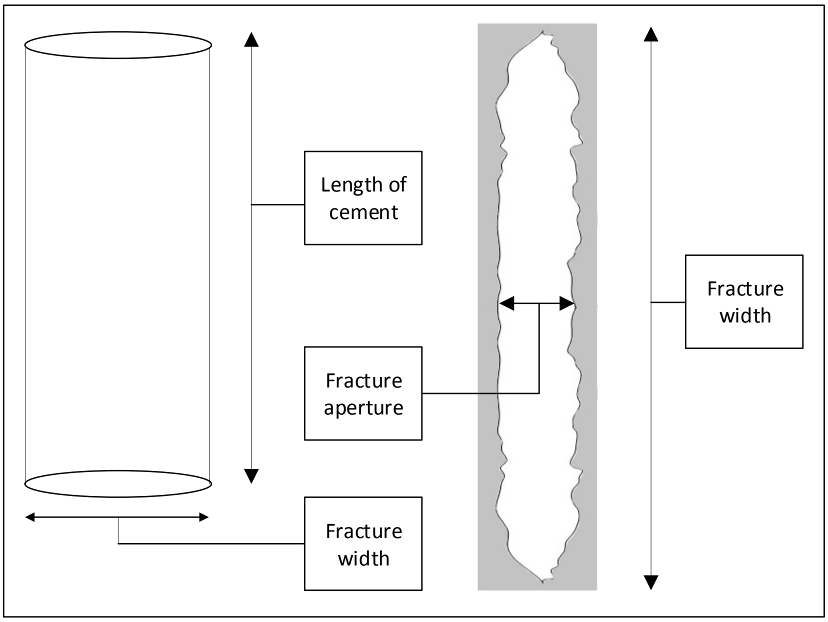

Figure 7-1: Fracture aperture and fracture width

7.1.3. Micro Annuli

When the cement body shrinks, micro annuli may also be formed between the cement body and the casing (see Chapter 4.1.4), allowing small amounts of fluid to bypass the plug either partially, or entirely in the worst-case scenario. The IRIS leakage calculator uses the following equation to estimate this leakage [37]:

$$Q = \left(\frac{\pi\, R_c\, \Delta P}{6\, \mu\, L}\right) \delta R^3$$

Where:
R_c – Casing diameter [m]
δR – Micro-annuli gap [m]

The gap of the micro-annuli is considered an uncertain parameter.

7.2. Simeo WellCem

Similar to the IRIS leakage calculator, Simeo WellCem by Oxand uses Darcy's Law to calculate flowrate. The software is divided into a one-phase model (water or gas), and a more complex bi-phasic (water and gas) model [1] [57]. The bi-phasic model has more assumptions, and the questionable gas permeability results (see Chapter 8) will affect the bi-phasic model [54]. Therefore, the bi-phasic model will be mentioned, but not focused on.

Unlike the IRIS Leakage calculator, Simeo WellCem does not separate between different leakage paths, but instead an effective permeability is used. This may be beneficial as an effective permeability can more easily be obtained through testing. However, as micro-annuli may have a large effect on the leakages, permeability testing where the micro-annuli can be included is recommended (e.g. Sandwich Joints).

7.2.1. One-Phase Model

In the one-phase model, the main assumptions are [57] [54]:

- Darcy's Law
- Compressible Newtonian fluid
- Laminar flow
- Steady State
- Unidirectional flow along the well
- Reynolds number << 1
- Reservoir pressure is applied at the bottom of cement interval
- Hydrostatic pressure is considered at the TOC

With the use of these assumptions, an equation for the flow rate is obtained [57]:

$$Q = -A * \frac{P_{bottom} - (P_{top} + \int_0^L \rho\ g \cos(\theta)\, dz)}{\int_0^L \frac{\mu}{\rho\ k}\, dz}$$

Where:
Q – Mass flow rate [kg/s]
A – Total area [m^2]
P_{bottom} – Pressure at bottom of cement interval [Pa]
P_{top} – Pressure at top of cement interval [Pa]
L – Length of cement interval [m]
ρ – Density of fluid [$\frac{\mathrm{kg}}{\mathrm{m}^3}$]
g – Gravitational constant (9.80 used in software) [$\frac{\mathrm{m}}{\mathrm{s}^2}$]
θ – Inclination of well from vertical [°]
Z – Depth [m]
μ – Viscosity of fluid [Pa s]
k – Intrinsic permeability of cement [m^2]

The inputs parameters for the software are given in Chapter 7.2.4, and these are then used to calculate the flowrate using the formula above.

7.2.2. Bi-Phasic Model

The main assumptions of the bi-phasic model are the same as for the one-phase model, but also includes [57]:

- *"No interaction between fluids"* [57]
- *"Continuity of the "wetting" fluid phase"* [57]
- *"Intrinsic permeability of the cement is independent of the fluid"* [57]

With the use of these assumptions the following equation for gas flowrate is obtained [57]:

$$Q_{nw} = s_{nw}\ k\ \frac{A\ \rho_{nw}}{\mu_{nw}} \left[(\rho_w - \rho_{nw})\ g \cos(\theta) + \frac{P_{Res} - P_{top} - \int_0^L \rho_w\ g \cos(\theta)\,dx - P_{c,bot}}{\frac{\rho_w\ k}{\mu_w} \int_0^L \frac{\mu_w}{\rho_w\ k}\,dx} + \frac{dP_c}{dz} \right]$$

Where:
nw – Non-wetting phase
w – Wetting phase
P_c – Capillary pressure [Pa]
s – Saturation ratio

7.2.3. Software

When starting the Simeo wellCem software, there are three main choices/menu's; 1) Reference flow rate, 2) Planning phase, and 3) Dispensation request.

7.2.3.1. Reference Flow Rate

As mentioned in Chapter 6.2, Simeo WellCem compares a well barrier to a reference case that fulfills NORSOK D-010, to assess the well barrier in a risk based approach. The menu "Reference Flow Rate" is utilized to create this reference case and the associated UAC. Embedded in the software is the well from the study of Godøy et al. [1] (see Chapter 6.2), and it is here the UAC of the liquid model is found. However, a new reference case can be set by expert users of the software.

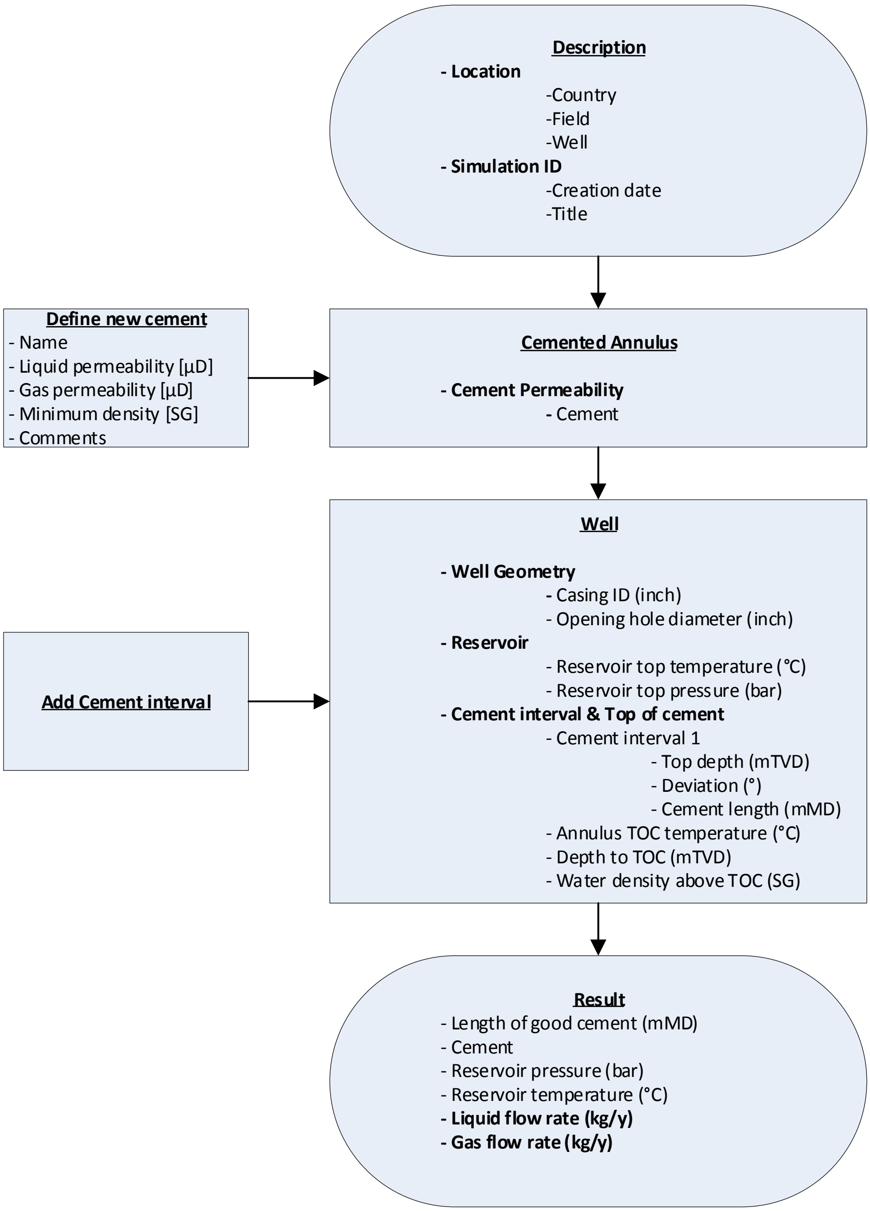

Figure 7-2: Information input for reference case in Simeo WellCem

When the necessary inputs for the reference case is added (see Figure 7-2), the software will calculate the yearly mass flow rate (liquid model and gas model), which defined the values for the UAC.

7.2.3.2. Planning Phase

The planning phase menu is designed to plan barriers in wells, where the minimum required length of good cement to satisfy the UAC can be calculated for both cemented annulus and plugs. A sensitivity analysis varying cement permeability and length can also be performed.

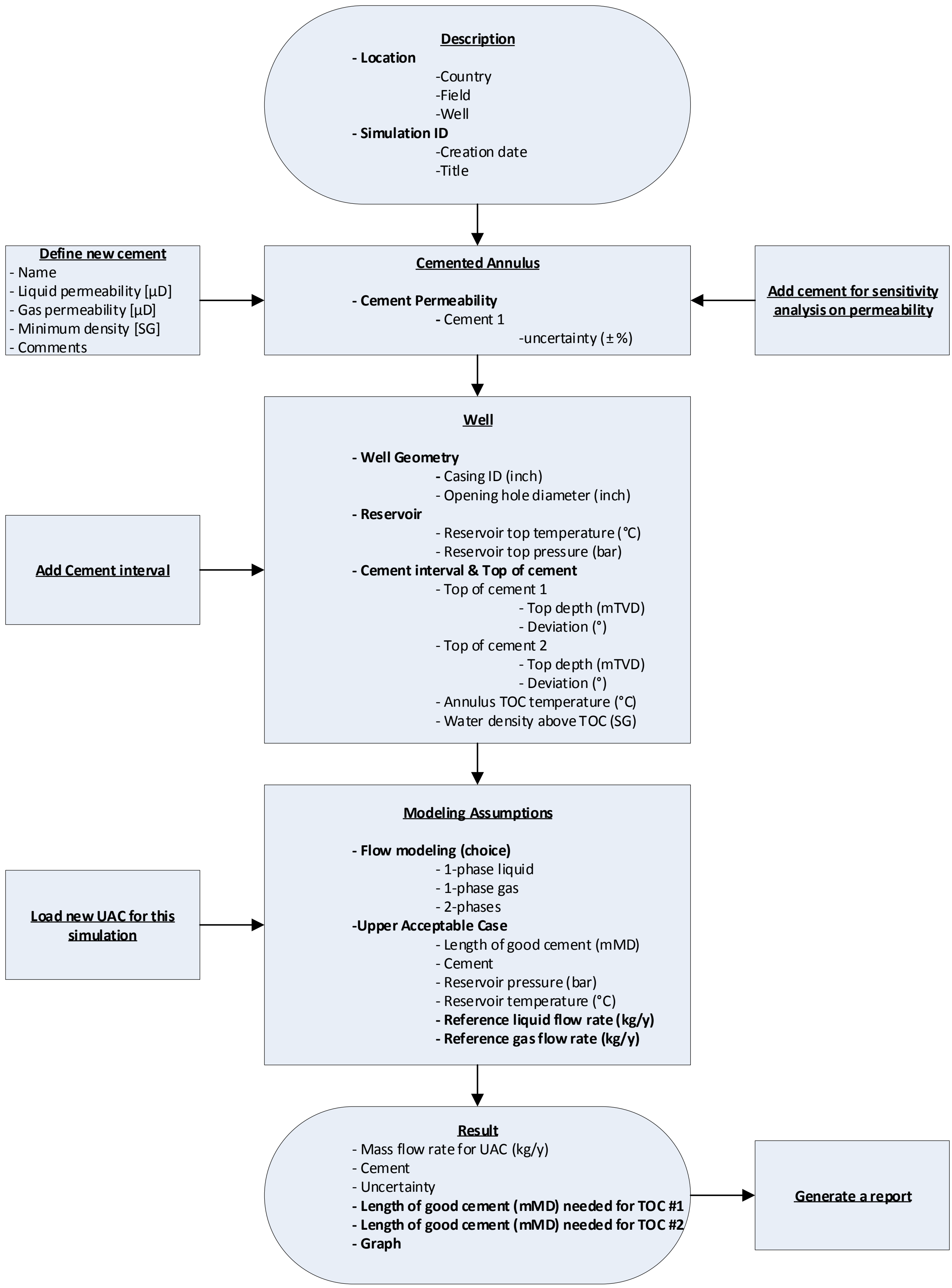

Figure 7-3: Information input for planning phase (annulus) in Simeo WellCem

When the necessary information has been added to the planning phase, the length of good cement needed to achieve the same leakage as the reference is shown. In addition, a graph with mass flow rate vs length of good cement is shown, where it is visualized what leakage can be expected with a given length of cement, including user defined permeability uncertainty.

For the calculations of this menu, the pressures (P_{TOC} and P_{RES}) and temperature (T_{TOC} and T_{RES}) are assumed independent of the length of cement, meaning that the same pressures and temperatures will be used for 1 m of good cement as 60 m of good cement (see Figure 7-4).

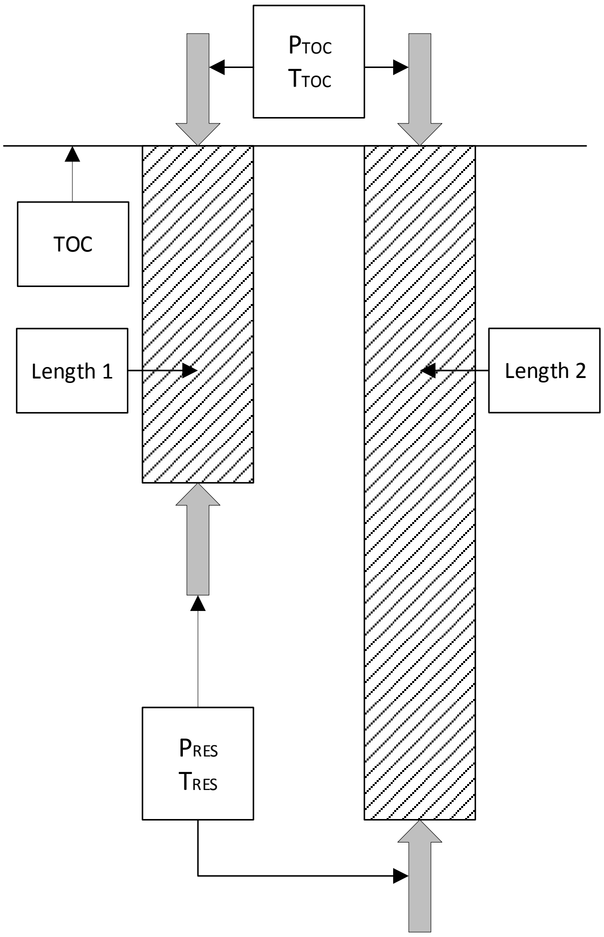

Figure 7-4: Same pressure at top and bottom independent of length.

7.2.3.3. Dispensation Request

The dispensation request menu lets the user compare a set of existing barriers against the reference case (see Chapter 7.2.3.1). To utilize this menu, how much good cement is available is needed as an input, so logging should have been performed. The process is divided into two steps; one for the primary barrier, and one for the secondary barrier:

1) The software estimates how much length of the good cement available is needed from bottom and up to satisfy the UAC. This will then be set as the primary barrier, and the associated leakage is shown.
2) The remaining interval of good cement is then compared to the UAC. If the associated leakage is lower than the UAC, then the software has confirmed that the total length should be enough for both the primary and secondary barrier. If this leakage is higher than the UAC, the software will show "failed".

The user can define a percentage uncertainty for the cement permeability in these simulations, and with uncertainty, three results will be shown; 1) permeability -x %, 2) permeability, and 3) permeability +x % (worst-case). When calculations are done, the user can print a report, which is intended as documentation for a dispensation request.

For the calculations of this menu, the pressures and temperatures will be different for primary and secondary barrier. While the reservoir pressure is assumed as the pressure on the bottom for both barriers, the pressure at the top will change as the depths change, because of resulting change in the hydrostatic pressure from water. For the temperatures, a linear trend is assumed, and the specific temperature is calculated for the different depths (see Figure 7-5). Resulting from this, a difference of length from the planning phase menu can be seen. This menu is intended for dispensation of logged wells, while the planning phase is intended to be used before logging to see what verified lengths are necessary.

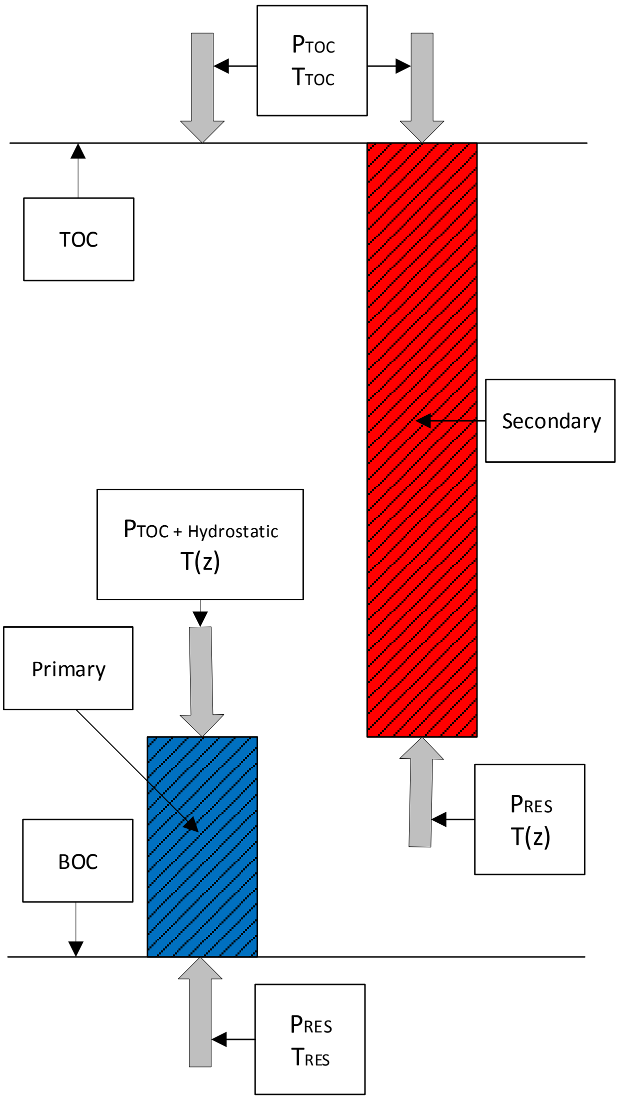

Figure 7-5: Different pressures and temperatures for the different barriers

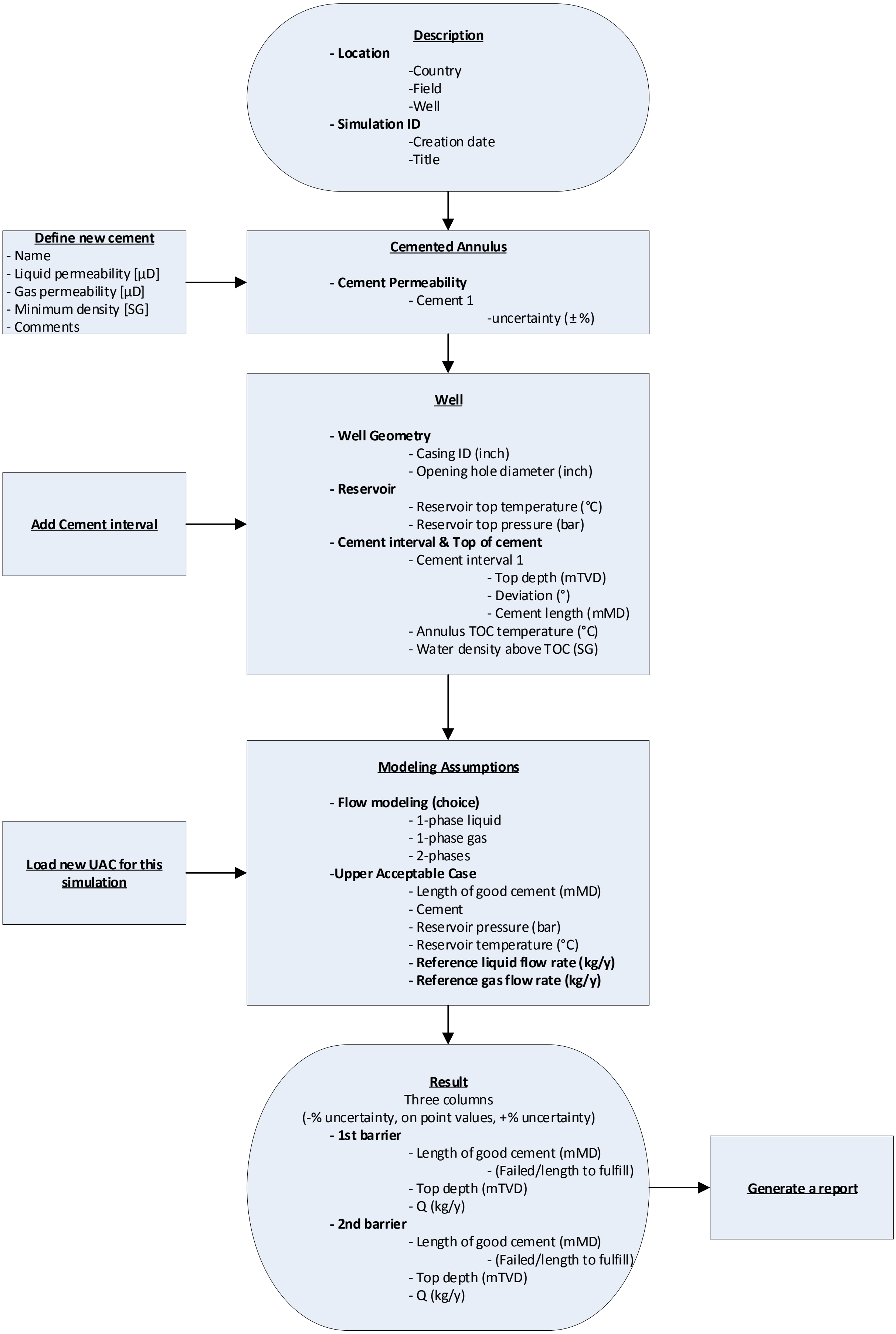

Figure 7-6: Information input for dispensation request in Simeo Wellcem

7.2.4. Inputs

Simeo WellCem is designed for quick simulations to make rapid decisions, and does not require a large span of inputs. Table 7-1 shows what inputs are needed for the different part of the software and the associated units.

Input	Unit	Define Cement	Building Reference	Planning Phase	Dispensation Request
Casing ID	inch	x	✓	✓	✓
Cement Density	SG	✓	x	x	x
Inclination	°	x	✓	✓	✓
Length of Good Cement	mMD	x	x	x	✓
Opening Hole Diameter	inch	x	✓	✓	✓
Permeability, Gas	µD	✓	x	x	x
Permeability, Liquid	µD	✓	x	x	x
Reservoir Pressure	bar	x	✓	✓	✓
Reservoir Temperature	°C	x	✓	✓	✓
TOC	mTVD	x	✓	✓	✓
TOC Temperature	°C	x	✓	✓	✓
Uncertainty	%	x	x	✓	✓
Fluid Density Above TOC	SG	x	✓	✓	✓

Table 7-1: Inputs needed for different tasks in Simeo WellCem

The pressure above the cement barrier (TOC) is assumed to be equal to the hydrostatic pressure of the fluid located here (e.g. sea water). It is worth noting that in the software, MSL (Mean Sea Level) depth should be used (offshore wells), as abandoned wells only have air above this depth. See Chapter 9 for actual use of the Simeo WellCem leakage calculator.

8. Permeability testing of Cement

Even though the effect of permeability and length of cement on leakage are proportional according to Darcy's law, the range of the permeability is much larger than the length, leaving it as the dominating factor (see Chapter 8.5). To achieve a representable value for the permeability of the shallow cement at Valhall, permeability tests have been performed on cement retrieved from actual wells connected to Valhall DP. In addition to cement taken from shaker while retrieving casing, new cement made from the same recipe has been tested by the manufacturer of the original cement.

These permeabilities will be discussed, and used in the leakage calculator with other data from Valhall DP wells.

8.1. Permeability Types

In the testing performed by professional parties for this thesis, there are two types of permeabilities that are tested; 1) liquid permeability and; 2) gas permeability. These are obtained by measuring the flow across a core for a given differential pressure and use of Darcy's law.

8.1.1. Liquid and Gas Permeability

Liquid permeability in these tests means that a water-wet cement plug has been tested with the flow of water through it. For gas permeability, the cement must be completely dry and the flow of gas through the plug is measured. These should not be understood as the amount of liquid (oil) and the amount of gas flowing through a sample in two-phase flow. In Simeo WellCem, the leakage rates reported are calculated as gas.

8.1.2. Intrinsic Permeability

As gas is easily compressed, the permeability measurements will be sensitive to pressures and temperature. To obtain a single permeability value that can be entered as an input into software's, the permeability should be intrinsic permeability. This means that the permeability is only a function of the material structure and not the state of the fluid [58]. It has been assumed that reported permeability are intrinsic.

8.2. Shaker Samples

Cement samples from a Valhall DP well, were retrieved. These cement samples were of sufficient size to drill out four small cores (not of standardized size for testing) that could be used for permeability testing. Both gas permeability (N_2) and water permeability (tap water) were tested. All testing and calculations are performed by a professional third party. The testing will be explained and the calculations reproduced.

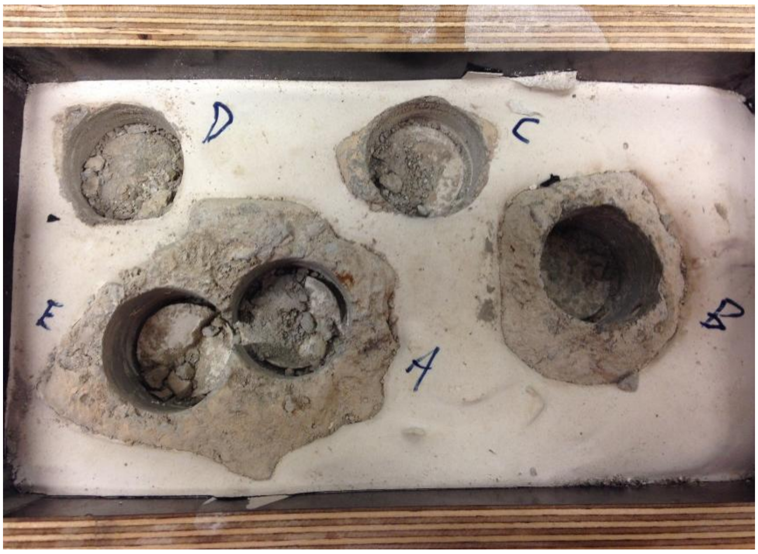

Figure 8-1: Shaker cement samples where cores have been drilled out

8.2.1. Cement Type

The cement samples are retrieved from shaker when cutting and pulling sandwich joints (see Chapter 8.4), meaning that it comes from the annular cement between the surface casing (20") and the intermediate casing (13 3/8"). According to the cement reports, the border between tail and lead cement are found at a depth of approximately 200m above the intermediate casing shoe [39]. As the sandwich joints are retrieved from a depth well above this transition, this cement is lead cement.

According to the cement reports for this well, the lead cement is class G Portland cement of 13.0 ppg. In this cement an extender called Econolite (sodium silicate) is found [39]. The role as an extender is to increasing volume, and decreasing density [59]. This additive is added in the amount of 0.4 GPS (Gallons Per Sack) for this cement [39].

This is the typical cement found behind the 13 3/8" casing at this depth on the Valhall DP well. However, in some of the wells a 15.8ppg cement was squeezed down the 20" x 13 3/8" annulus and placed across seal #2.

8.2.2. Cement Cores

The gas permeability was tested first. This was found practical as a completely dry core was needed for gas permeability testing. Four cement cores were retrieved, dried and tested. After the gas permeability test, dismantling of the test equipment resulted in destroying three out of four cores. The last core holder was not dismantled, but instead water permeability was tested in the same core holder, to avoid destroying all cores. In Table 8-1, the dimensions of each core can be seen.

Plug	**A1**	**A2**	**C**	**D**
Length [cm]	2.073	1.343	1.185	1.707
Diameter [cm]	2.535	2.533	2.529	2.523

Table 8-1: Dimensions of cement cores

8.2.2.1. Gas Permeability testing:

Figure 8-2 shows the testing configuration used, while Figure 8-3 shows the cross section of the core holder. Inside, there are two chambers; one for the cement core, and one that is pressurized to 43 bars. This pressure is equivalent to an overburden pressure. To control the pressure difference, and ensure it is within what the system could handle, a backpressure was added, leaving the pressure difference across the samples around 20 bars.

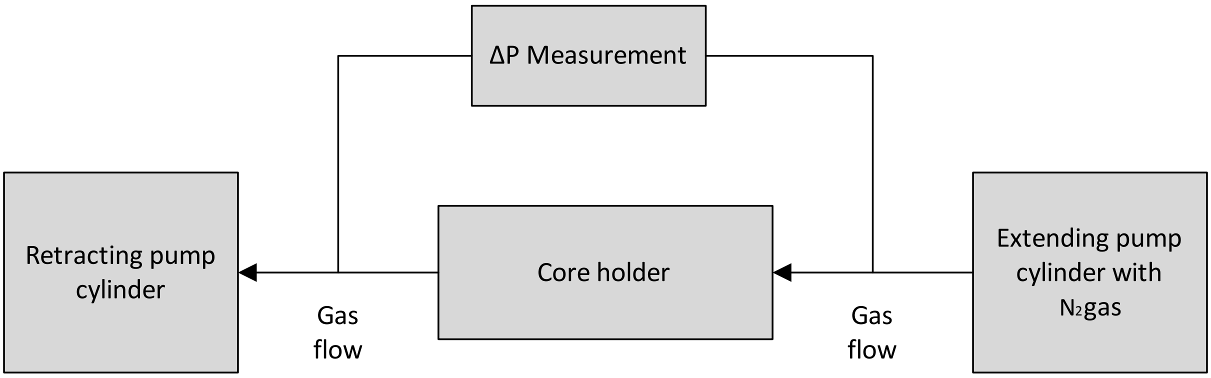

Figure 8-2: Testing configuration for permeability testing

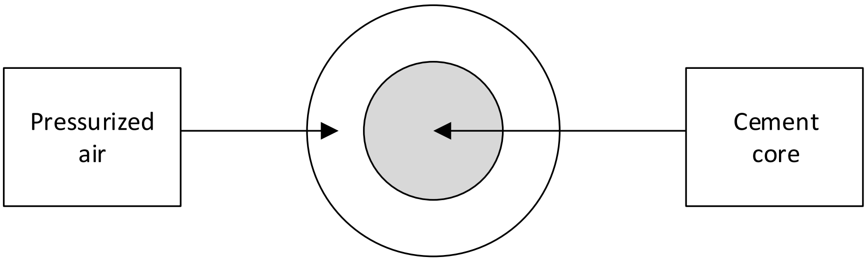

Figure 8-3: Schematic of core holder cross-section

8.2.2.2. Water Permeability testing:

For testing of water permeability, only one cement core was intact. This core was tested with an overburden pressure of 33 bars, and a back pressure of 10 bars. The water used was tap water at a temperature of 22 °C with a viscosity of 0.95375 cP [60].

8.2.3. Calculating Permeability

Calculations of permeability from the cores have been performed along with the testing by the same third party. This chapter aims to explain the principles used for calculating permeability. Even though it may seem as though uncertainty is not included, both system resistance such as friction and uncertainty due to measuring is included in the calculations. Before permeability can be calculated, pressure loss across the plug and gas viscosity are found.

8.2.3.1. Hagen-Poiseuille's Law

For calculating the pressure difference across the cores, the Hagen-Poiseuille law was used. In this law, the following assumptions are present [61]:

a) Incompressible Newtonian fluid

b) Laminar flow
c) Constant cross section
d) Cylindrical pipe
e) Length is substantially larger than its diameter
f) No acceleration

When these criteria are fulfilled, the law is valid and is as follows [61]:

$$\Delta P = \frac{8\,\mu\,L\,Q}{\pi\,r^4}$$

Where:
$\Delta \mathrm{P}$ – Pressure difference across pipe [Pa]
L – Length of pipe [m]
μ – Dynamic viscosity [Pa s]
Q – Volumetric flowrate $[\frac{\mathrm{m}^3}{\mathrm{s}}]$
r – pipe radius [m]

The third party used the Hagen-Poiseuille's law to calculate the pressure differential both for the water and gas tests. Even though gas is compressible, the test was performed at an elevated pressure. The pressure drop across the core is small in comparison to this confining pressure such that the relative gas expansion is small.

After converting the units to the ones in use, the following equation is derived [60]:

$$\Delta \mathrm{P[mbar]} = 4.244 * 10^{-7} * \frac{\mu[\mathrm{cP}] * \mathrm{L[cm]} * \mathrm{Q[ml/min]}}{\mathrm{r\ [cm]}^4}$$

8.2.3.2. Sutherland's Formula

To include the effect of temperature on gas viscosity, Sutherland's formula has been used [60].

$$\mu = \mu_0 * \frac{a}{b} * \left(\frac{T}{T_o}\right)^{\frac{3}{2}}$$

$$a = 0.555T_o + C$$

$$b = 0.555T + C$$

Where:
μ - Viscosity at temperature T [cP]
μ_0 – Viscosity at reference temperature T_o [cP]
T – Input temperature [°R]
T_o – Reference temperature [°R]
C – Sutherland's constant

Table 8-2 shows the reference values, Sutherland's constant and viscosity calculations for the gas at test conditions [60].

Plug	A1	A2	C	D
Fluid	N_2	N_2	N_2	N_2
Temperature [°C]	18,5	18,5	18,3	18
Temperature [°R]	524,97	524,97	524,61	524,07
Fixed Values				
C	111,00	111	111	111
T_0 [°R]	540,99	540,99	540,99	540,99
μ_0 [cP]	0,01781	0,01781	0,01781	0,01781
Calculations:				
a	411,24945	411,24945	411,24945	411,24945
b	402,36	402,36	402,16	401,86
Viscosity [cP]	**0,017401**	**0,017401**	**0,017392**	**0,017378**

Table 8-2: Viscosity of gas for shaker samples

8.2.3.3. Darcy's Law

After the pressure difference and viscosity are estimated, Darcy's law can be used to calculate the permeability as flowrate is known [62].

$$Q = \frac{k\,A}{\mu}\left(\frac{\partial P}{\partial x}\right)$$

Where:

k – Permeability $[\mathrm{m}^2]$

$\left(\frac{\partial P}{\partial x}\right)$ – Pressure change per unit length $[\frac{\mathrm{Pa}}{\mathrm{m}}]$

For the permeability calculations, we are interested in the average permeability of the whole plug, therefore we can look at ∂x and ∂P for the entire interval of the plug:

∂x - is set as the length of the plug (L)

∂P – is set as the pressure drop (ΔP), estimated in Chapter 8.2.3.1.

$$k = \frac{\mu\,L\,Q}{A\,\Delta P}$$

To simplify these calculations a value R has been defined as [60]:

$$R = \frac{245000}{14.5038} * \frac{\mu[\mathrm{cP}] * L[\mathrm{cm}]}{A\,[\mathrm{cm}^2]}$$

The resulting version of Darcy's law with the use of the value R [60]:

$$k\,[\mathrm{mD}] = \frac{R * Q[\frac{\mathrm{ml}}{\mathrm{min}}]}{\Delta P[\mathrm{mbar}]}$$

8.2.4. Results

From the testing of the cement cores, the permeabilities in Table 8-3 were calculated [60]. These permeabilities are effective permeabilities, meaning that they will be affected by the presence of abnormalities (e.g. cracks as mentioned in Chapter 7.1.2). This impact will be more evident in smaller samples than in larger, and may be some of the reason behind the high permeability in sample A2. As the results from this sample is very different than the others, it is considered an anomality, and will be ignored.

Plug	**A1**		**A2**		**C**		**D**			
Length [cm]	2,073		1,343		1,185		1,707			
Diameter [cm]	2,535		2,533		2,529		2,523			
Area [cm2]	5,047		5,039		5,023		4,999			
Fluid	N_2		N_2		N_2		N_2		Water	
Temperature [°C]	18,5		18,5		18,3		18		22	
Viscosity [cP]	0,017401		0,017401		0,017392		0,017378		0,95375	
Analysis										
Flowrate* [ml/min]	0,00	1,00	0,00	1,00	0,00	1,00	0,00	1,00	0,00	1,00
Pressure* [mbar]	26,07	294,03	-2,94	-1,97	-2,36	7,38	-20,47	-2,74	118,37	14646,85
R	120,729		78,338		69,305		100,229		5500,827	
Permeability [mD]	**0,45**		**80,76**		**7,12**		**5,65**		**0,38**	

*From regression analysis after being corrected for system resistance.

Table 8-3: Permeability results of shaker samples

Because the cores were destroyed during dismantling after the gas permeability testing, and because the results have a large span, more extensive testing is recommended. In proper testing the cores should be substantially longer. However, as this testing was performed on cement samples found on shaker after cut and pull operation, it was not possible to use regular size cores. Therefore, some of the results should be discarded (A2 in particular).

It is also worth noting that for this test setup, the effective permeability will be found including features such as small cracks. However, micro-annuli between cement and casing is not tested as this is done on cement cores in core holders. The effect of micro-annuli is something that should be looked more into for further investigation of the method.

8.3. New Batch of Original Recipe

Based on cementing reports, a new batch of the same lead cement as the one used in the wells at Valhall DP were prepared and tested by the manufacturer. The testing is performed according to internal specifications, so the methodology is not known. The results are presented as reported.

8.3.1. Water Permeability

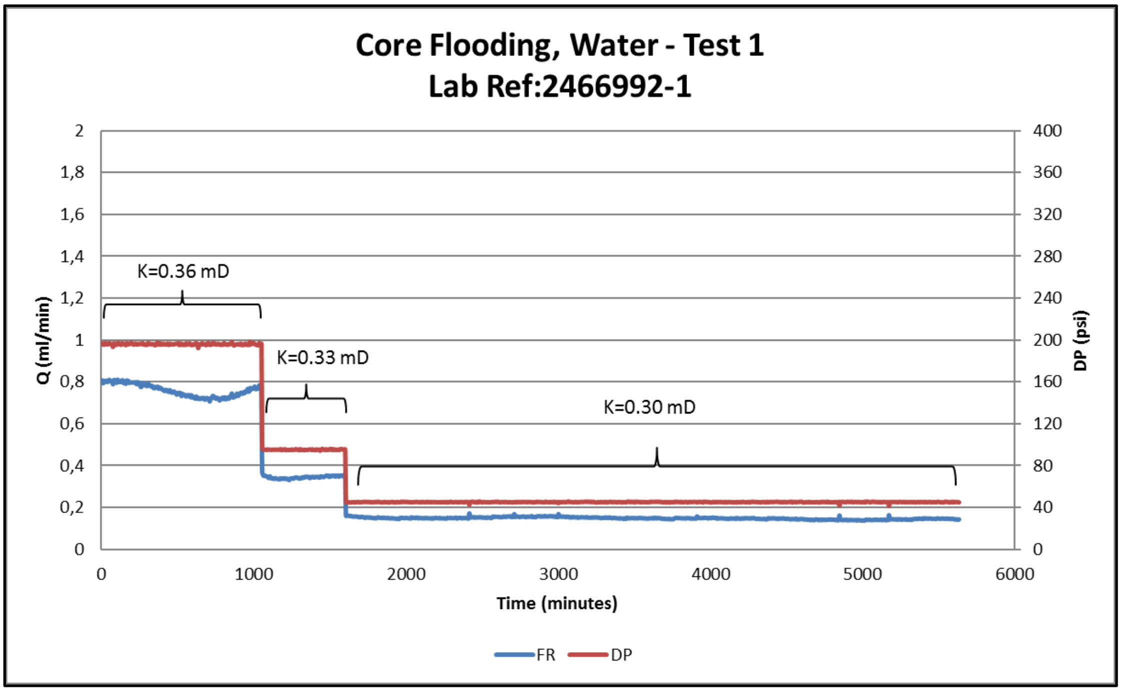

Figure 8-4: Manufacturer water permeability test #1 [63]

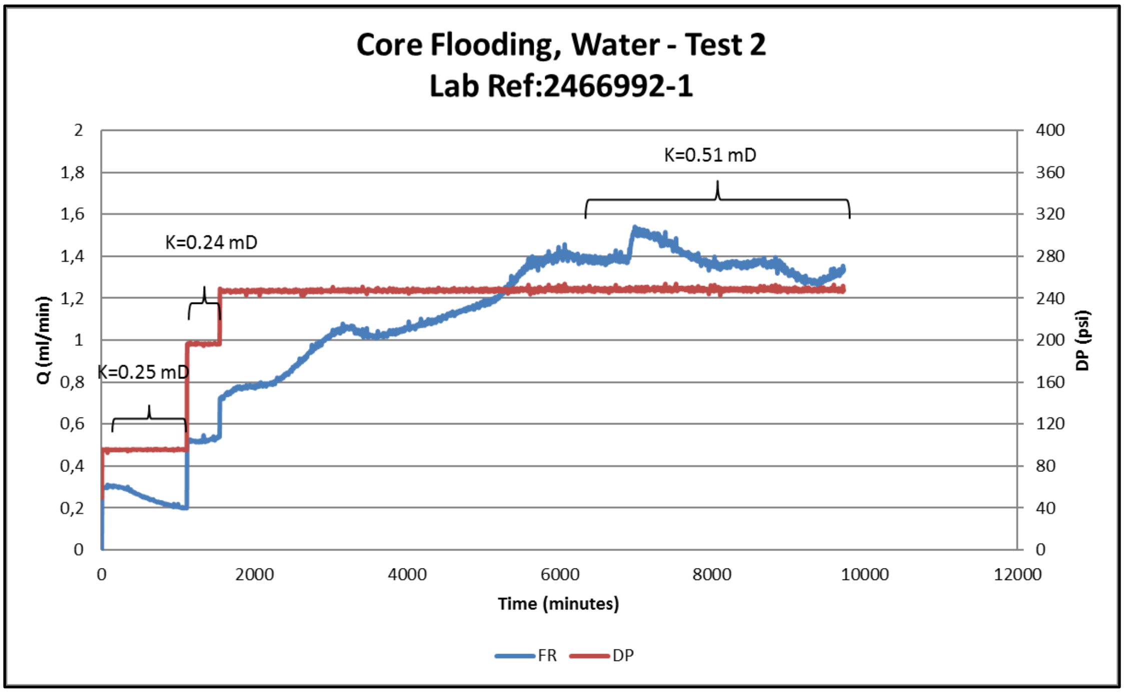

Figure 8-5: Manufacturer water permeability test #2 [63]

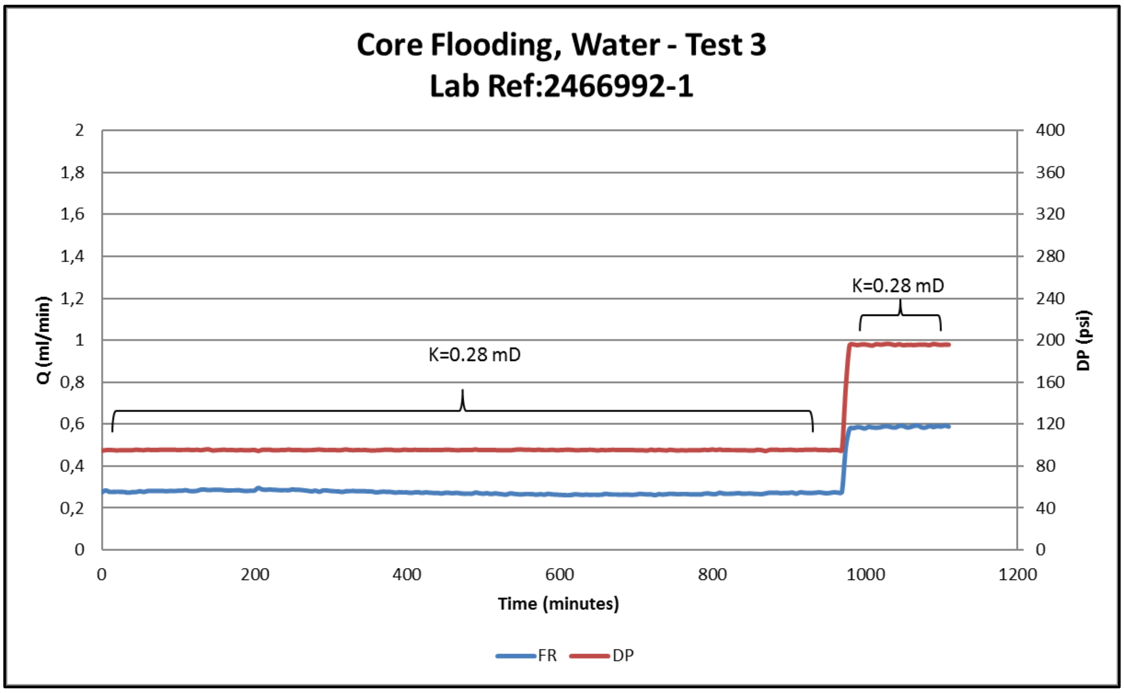

Figure 8-6: Manufacturer water permeability test #3 [63]

Test	Reported Permeability [mD]
#1	0.329
#2	0.249
#3	0.280
Average	**0.286**

Table 8-4: Reported water permeability from manufacturer [63]

8.3.2. Gas Permeability

For the gas permeability test on the prepared cement, N^2 was used [63].

Dp [psi]	Dp [bar]	Permeability [mD]
49	3,4	1,38E-03
95,4	6,6	1,07E-03
150	10,3	9,00E-04
201	13,9	7,90E-04
250	17,2	7,20E-04
52	3,6	1,50E-03
99,5	6,9	1,14E-03
149	10,3	1,57E-03
198,7	13,7	8,00E-04
247,9	17,1	7,30E-04
32,5	2,2	1,55E-03
Average		
138,6	**9,6**	**0,001105**
Standard Deviation		0,000342

Table 8-5: Manufacturer gas permeability test #1 [63]

8.4. Sandwich Joints

To achieve representable permeability data from the wells at Valhall DP permeability testing on sandwich joints retrieved from the wells were planned along with the other testing. Sandwich joints are casing strings of two consecutive casings with the annular cement intact between them. With the testing of sandwich joints, the effect of micro annuli would be included in the effective permeability. However, to utilize these sandwich joints, it was crucial that they could be correlated with cement logs (i.e. Cement Bond Log/Variable Density Log) showing adequate quality such that they would be considered as WBE. The Sandwich joints at our disposal were of a considerable amount. However, the best quality available was set to "moderate" in analyses performed by an international service company [64]. Moderate is not sufficient to be considered as a WBE by Aker BP, so these sandwich joints were not tested. However, a project is in place to perform these tests when adequate samples are available.

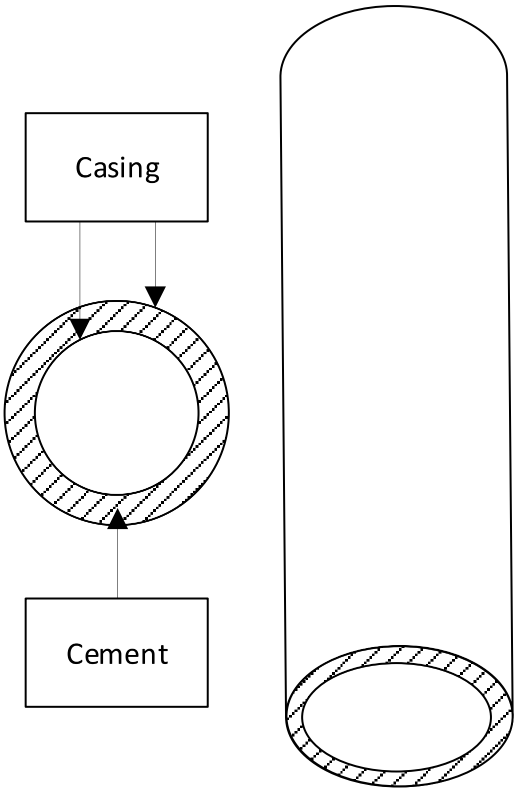

Figure 8-7: Sandwich joints

Sandwich joints of acceptable quality have been retrieved at a later stage, but are made available for permeability testing a time after the deadline for this thesis. As the lack of sandwich joints testing leaves the planned dataset incomplete, the utilization of the sandwich joint testing or alternate testing of cement permeability is recommended before the methodology discussed in this thesis is used. It is crucial to have a reliable estimate of the cement permeability.

8.5. Conclusion of Cement Permeability from Testing

In the permeability testing performed for use in this thesis the permeabilities varies, ranging from 1.11 µD to 7.12 mD. The impact of the factor of difference between µD and mD on the cement length will turn 30 m into 30 000 m. Because of the range alone, permeability is the dominating factor.

8.5.1. Liquid Permeability

Table 8-6 summarizes the liquid permeabilities from testing.

Liquid Permeability [mD]	
Manufacturer	Retrieved Cement
0.329	0.38
0.249	
0.280	
Average	
0.310	
Deviation, σ	
0.050	

Table 8-6: Liquid permeability test results

A higher number of samples would give more certainty to the permeability. The average liquid permeability of 0.310 mD is very different from the one of the reference well used in the study of Godøy et al. [1] [54] of 1.43 µD. However, all measured values are lower than the range of low-density cement mentioned in Nelson et Guillot "*Well Cementing*" of 0.5 – 5.0 mD [28].

8.5.2. Gas Permeability

Table 8-7 summarizes the gas permeabilities from testing.

Gas Permeability [mD]	
Manufacturer	Retrieved Cement
0.001105	0.45
	80.76*
	7.12
	5.65
Average	Deviation, σ
3.305	3.127

*Anomality

Table 8-7: Gas permeability test results

There is a clear difference between the testing from the manufacturer and retrieved cement tested by the third party (see Table 8-7). This large difference might be because the cement tested by the manufacturer is new, while the one tested by the third part has been downhole for many years. Other possibilities are the size of the cores tested, or damage caused by the drying process [31]. The small size makes the results vulnerable to cracks and other abnormalities. Therefore, it is recommended to do further testing on the gas permeability before using numbers. As a result, the numbers from the shaker sample cores are not relied on.

9. Use of Simeo WellCem

By using the lengths required in NORSOK D-010, the focus will be on where barriers of accepted lengths can be placed in the well, instead of where in the well the barriers will function best as a seal. A deeper set annular cement of 25 m may be better than a shallower set cement of 30 m, as the pressure difference may be lower, the formation is typically strengthened with depth, and the quality of the cement may be better in that location (e.g. better bonding and/or tail cement instead of lead cement). Thus, it might be better to find alternative ways to verify the cement in place, than to simply look at barrier lengths.

In this chapter, the shallower barriers of the Valhall field will be assessed with the Simeo WellCem leakage calculator. To do so, the inputs must be estimated/gathered, where the focus has been put on the main factor; permeability.

To assess these data's, a reference case is needed, so that a reasonable comparison can be made. Such a reference case is built in the study presented in Chapter 6.2. However, as this reference is made by another operator where not all data is available and can be assessed, a separate reference case will be built for Aker BP. This reference case will be based on the condition deeper in the wells at Valhall DP, and built on the same principles as the reference case in the study by Godøy et al. [1]. The reference case from the Godøy et al. study [1] will also be used for comparison (see Chapter 9.2).

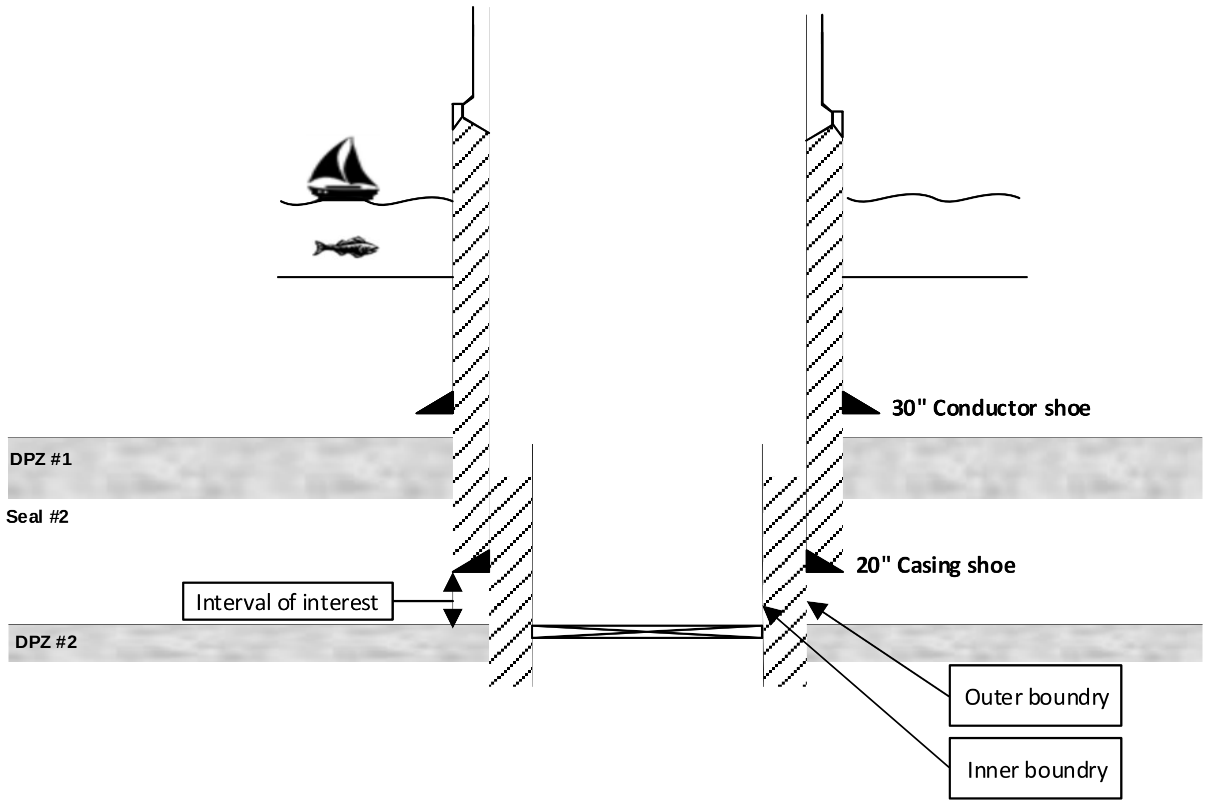

Figure 9-1: Schematic of shallow parts of a typical well at Valhall DP

9.1. Estimation of Inputs

The necessary inputs into the Simeo WellCem leakage calculator can be found in Table 9-1.

Input	Unit	Define Cement	Building Reference	Planning Phase	Dispensation Request
Casing ID	inch	x	√	√	√
Cement Density	SG	√	x	x	x
Inclination	°	x	√	√	√
Length of Good Cement	mMD	x	x	x	√
Opening Hole Diameter	inch	x	√	√	√
Permeability, Gas	µD	√	x	x	x
Permeability, Liquid	µD	√	x	x	x
Reservoir Pressure	bar	x	√	√	√
Reservoir Temperature	°C	x	√	√	√
TOC	mTVD	x	√	√	√
TOC Temperature	°C	x	√	√	√
Uncertainty	%	x	x	√	√
Fluid Density Above TOC	SG	x	√	√	√

Table 9-1: Inputs needed for different tasks in Simeo WellCem

Most of these values are easily set, and are very similar for most of the wells at Valhall DP in the higher sections of the wells (here taken from the same well as the tested retrieved cement):

- **Casing ID:** 13 3/8 casing will be used, as it is the cement behind this casing that can be verified.
- **Inclination:** At 399 mTVD (20” casing shoe), we have an inclination of 9.4° [7].
- **Length of good cement:** 30 mMD will be considered for calculating leakage through this barrier, as this is what makes the annular WBE acceptable according to NORSOK D-010 when the cement is verified.
- **Opening hole diameter:** The bit used to drill this section was a 17 1/2” bit, so that will be the diameter used.
- **TOC:** Even though the cement extends above the 20” casing shoe, this interval cannot be logged, so that the TOC will be considered at the 20” casing shoe (399 mTVD). As this depth is used to calculate the hydrostatic pressure from sea water, the air gap of 64 mTVD (Maersk Invincible) will be subtracted. This gives a hydrostatic sea water column of 335 mTVD (MSL) at TOC.
- **Fluid density above TOC:** Sea water with a gradient of 1.025 s.g. will be considered here.

The remaining inputs are: Cement properties (including permeability) (see Chapter 9.1.1), reservoir pressure (see Chapter 9.1.2) and temperatures (see Chapter 9.1.3).

9.1.1. Cement Properties Including Permeability Test Data

- **Cement density:** According to the cement reports, 13.0 Lbs./Gal. cement is expected to be found here (1.56 s.g.). The density is not a part of the calculations, and the input is used for documentation purposes.

- **Uncertainty:** For the liquid permeability, the standard deviation from testing has been transformed into a percentage as the input into the software is percentage uncertainty. The resulting percentage is 16%.

From the permeability testing described in Chapter 8, a single permeability input must be chosen for each of the one-phase models. For the liquid one-phase model, an average permeability has been used as these measurements are relatively similar. However, for the gas model the measurements vary too much to use a similar approach.

In the gas one-phase model, a completely dry cement is assumed. However, in a well the cement will be saturated by water or other liquid found in the well. In addition, as the gas permeability results shows a spread with a factor of more than 6000 (excluding the anomality of 80.76 mD), the gas permeability measured by the cement producer has been used. This permeability has been chosen as the size of these cores are expected to be of a more dependable size. The focus will be on the simulation results from the liquid one-phase model.

When Simeo WellCem was taken into use, the range of liquid permeability accepted by the software was in the range 0 – 10 µD [54]. However, as the testing described in Chapter 8 shows permeabilities far greater than this, a change to the software was needed. The current version now accepts liquid permeabilities as high as 100 000 µD (= 100 mD), and this is one of several changes made to the software because of this thesis.

Liquid Permeability [mD]	
Manufacturer	**Retrieved cement**
0,329	0,38
0,249	
0,280	
Average	
0,310	
Deviation	
σ	**%**
0,050	**16 %**

Table 9-2: Liquid Permeability

9.1.2. Estimation of Pressures

Normally, the pressure differential across the barrier will be defined by: 1) reservoir pressure and 2) hydrostatic pressure from water (worst-case). For the bottom pressure, the reservoir pressure will not be used, as this is not relevant for this thesis. Instead, the maximum pressure at the bottom of the barrier will be used, as this is the highest pressure the barrier should hold. For Seal #2, the maximum pressure will be the highest expected pore pressure, because DPZ #3-5 is not expected to have an impact.

For the hydrostatic pressure from seawater, a gradient of 1.025 s.g. will be used. In Figure 9-2 the maximum expected pore pressure from this well is shown with the pressure gradient of sea water.

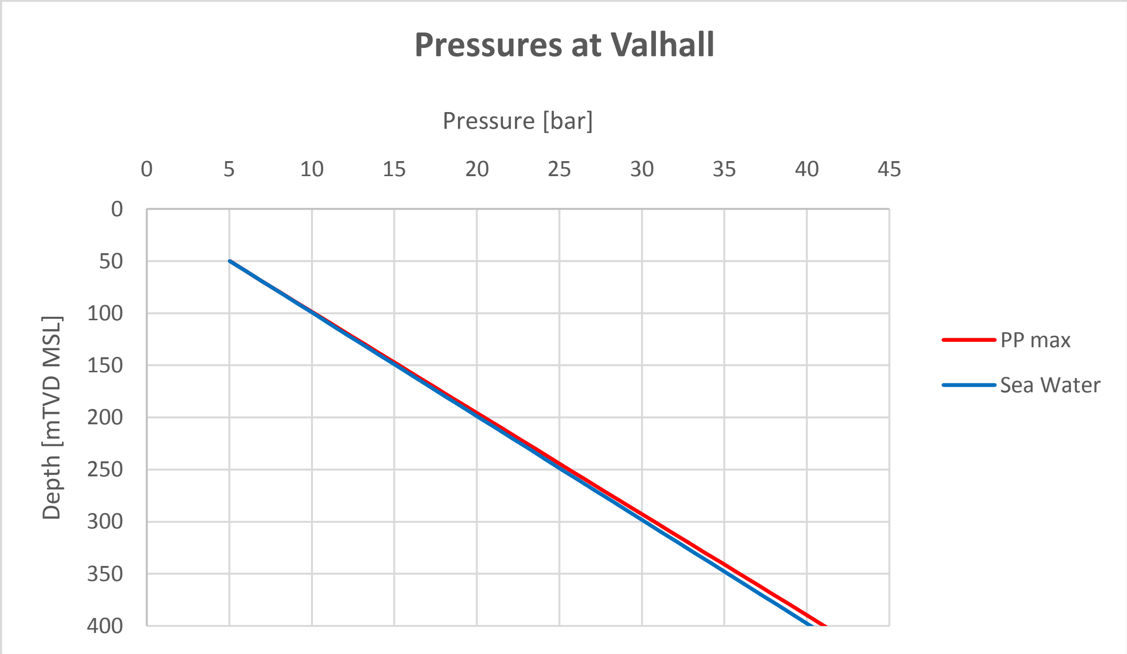

Figure 9-2: Maximum expected pore pressure and hydrostatic pressure from sea water [65].

For Seal #2 in the studied well, the maximum expected pressure at the bottom is 35.9 bar (520.6 psi) [7].

9.1.3. Estimation of Temperature

There are large variations in the temperatures at the shallow zones of Valhall. These variations come from heating caused by production from nearby wells. However, the temperatures are on the low side, ranging from approximately 15 to 37 °C (see Figure 9-3). In these simulations, the worst-case scenario of 37 °C is considered.

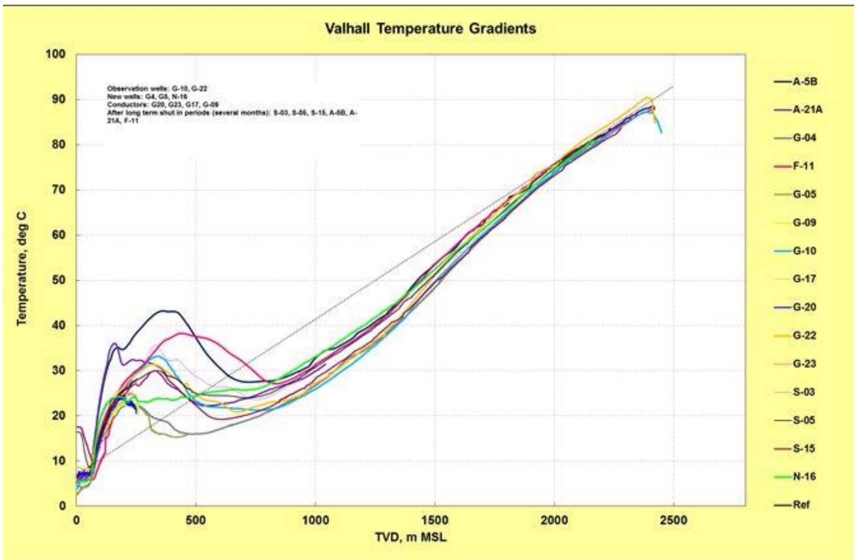

Figure 9-3: Valhall subsurface temperatures [66]

9.1.4. Leakage through Seal #2

When running the reference flow rate menus in Simeo WellCem with these inputs, the leakage rates in Figure 9-4 are obtained.

Length of good cement (mMD)	30
Cement	csath - Average cement 13ppg
Reservoir pressure (bar)	35.9
Reservoir temperature (°C)	37
Liquid flow rate (kg/y)	-2.07
Gas flow rate (kg/y)	0.04

Figure 9-4: Leakage through 30 m MD barrier in seal #2 [67]

Here the calculated leakages based on the permeability tested cement are shown for 30 mMD of cement with the use of the liquid one-phase model (2.07 kg/year downwards) and gas one-phase model (0.04 kg/year). As mentioned in Chapter 8.1.1, this is not to be confused as the amount of gas and oil flowing through the barrier, but are different models.

9.2. Comparison with Reference Case from Chapter 6.2

The UAC for gas flow rate from the Godøy et al. study [1] was set to 0.98 kg/year, while for liquid the UAC was not mentioned. For the liquid flow rate, one can consult the reference case defined in the software, as the parameters are identical to the one used in the study. The UAC for liquid flow rate is 10.22 kg/year where a liquid permeability of 1.43 µD is used [1] [67].

When comparing this reference case with Seal #2 at the Valhall field, the “Planning phase” menu for annulus (see Chapter 7.2.3.2) has been used in combination with the one-phase liquid model (see Chapter 7.2.1).

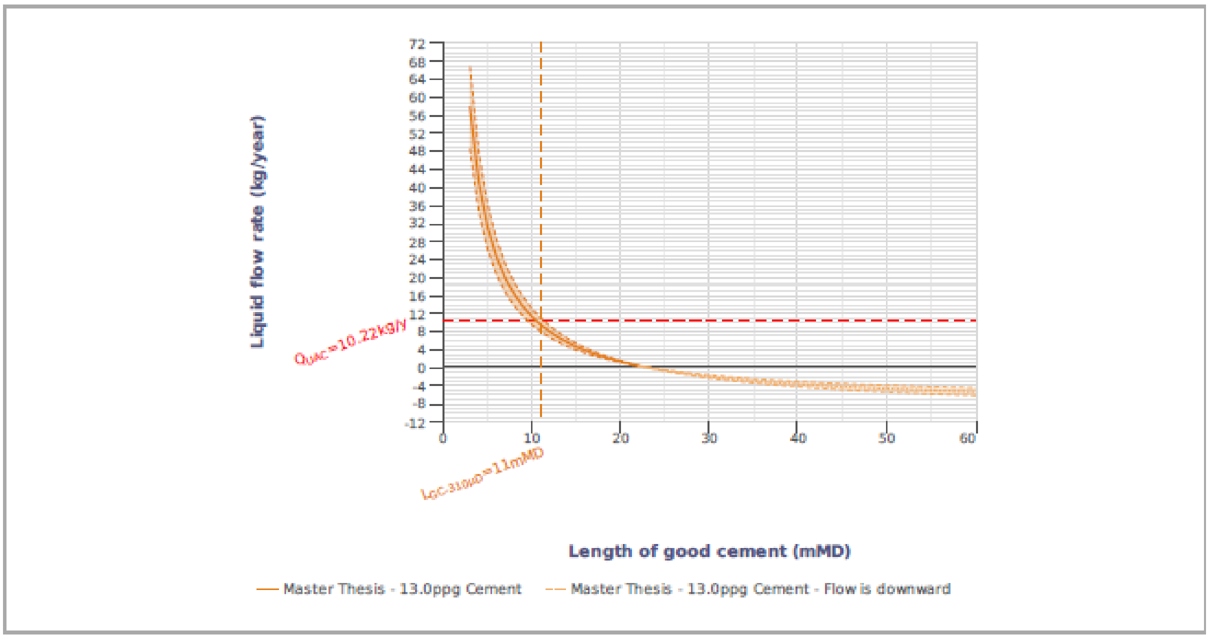

Figure 9-5: Planning phase on annulus [67]

In Figure 9-5 the leakage goes to negative values and is a phenomenon that happens due to the small pressure differential. In the equation used (also presented in Chapter 7.2.1), the hydrostatic pressure of water is calculated as a function of depth (see equation below). This is also done inside the cement interval (as the cement length is reduced), and because of the low differential pressure at these shallow depths, the pressure difference in the equation turns negative. Meaning that at some point equilibrium is obtained (in the equation) before the flow turns downwards. When this happens in the simulations, the lines will go to negative values and change into dotted lines. A downward flow ensures no HC flow upwards and is a good result. Because these simulations are based on a worst-case scenario with the lowest gradient on top (water gradient), and the highest expected pressure below, the upwards leakage potential is very low for the conditions of the simulation.

$$Q = -A * \frac{P_{bottom} - (P_{top} + \int_0^L \rho\ g \cos(\theta)\, dz)}{\int_0^L \frac{\mu}{\rho\ k}\, dz}$$

It is worth noting that downward flow (or zero leakage) is not a result that is obtainable for most barriers, as the pressure differential is normally more dominating than the hydrostatic pressure from sea water over the cement length.

According to the simulation, the leakage through an external barrier of 11 mMD (see Figure 9-5) will be equivalent to the UAC of the reference case from the Godøy et al. study [1] [67] with the use of the one-phase liquid model. However, to use this method, a satisfactory confidence in the data quality is necessary. A confidence that other operators might not have for the reference case of Godøy et al. [1].

9.3. Building New Reference Case

As the reference case from the study performed by Godøy et al. [1] (see Chapter 6.2) is from another operator, a new reference case is built for Aker BP. A barrier from an Aker BP well fulfilling the NORSOK D-010 requirements is used to create this reference.

9.3.1. Estimation of Inputs for Reference Case

Seal #9 is the seal covering the main reservoir at Valhall, and is the seal subjected to the highest pressures in these wells. The barriers across seal #9 in the well of the retrieved cement samples at Valhall DP is used. This is a barrier fulfilling NORSOK D-010 requirements and will be used as the Aker BP reference case in this thesis. The inputs from this well are:

- **Casing ID:** 7 5/8" liner.
- **Cement density:** According to the cement reports, 15.8 Lbs./Gal. cement is expected to be found here (1.89 s.g.).
- **Cement Permeability:** It was expected that the cement manufacturer had data on these permeabilities, as they are meant to be part of the main barriers in the wells. It turned out that this data was not available. Therefore, a liquid permeability of 10 µD has been assumed. This number is taken from UK guidelines and *"is typical of good cement"* [53]. For the gas permeability, a value of 0.1 µD has been assumed, and represents the best quality cement used in the study of Godøy et al. [1]. As the best quality cement has the lowest leakage rates, this will be the worst-case value in the perspective of this thesis.
- **Inclination:** At the TOC the inclination is 53.0°, while at the bottom, the inclination is 51.8°. An average inclination of 52.4° is used [7].
- **Length of good cement:** As this is to be used as a reference case, 30 mMD will be considered.
- **Opening hole diameter:** The bit used to drill this section was a 9 5/8" bit.
- **TOC:** The bottom of cement is at 2417 mTVD/4057 mMD from MSL (Mean Sea Level). With a 30 mMD interval of cement, the TOC will be 2398mTVD/4027 mMD from MSL.
- **Fluid density above TOC:** Sea water with a gradient of 1.025 s.g. will be considered.
- **Reservoir Pressure:** The virgin reservoir pressure is assumed, which is approximately 6500 psi or 448.2 bar depending on location at the field. This pressure is also close to the fracture pressure, as there are natural fractures present in the reservoir cap rock leading to the charging of DPZ #7.
- **Temperature TOC:** The temperature at TOC is assumed to be 88°C, and this is taken from the Valhall temperature profile [66].
- **Reservoir temperature:** A Reservoir temperature of 88°C has been used, and this is taken from the Valhall temperature profile, and is equal to the virgin reservoir temperature [66] [36].

9.3.2. Leakage Rate

When entering these inputs into the Simeo WellCem software, the results in Figure 9-6 are shown.

Length of good cement (mMD)	30
Cement	Master Thesis - 15.8ppg Cement
Reservoir pressure (bar)	448.2
Reservoir temperature (°C)	88
Liquid flow rate (kg/y)	11.1
Gas flow rate (kg/y)	0.29

Figure 9-6: Aker BP reference case leakage rates [67]

It can be seen that the liquid flow rate is close to the UAC from the Godøy et al. reference case (10.22 kg/year), while the gas flow rate is lower (0.98 kg/year) [67] [1].

An important aspect when talking about HC leakage is the harm to the environment. A study performed by Mari Røstvig Tveit [68] shows that for gas, more than 95% of the leakage is absorbed by the sea-water. The exact value is dependent on weather conditions, bubble size and other conditions. Still, less than 5% reaches surface.

The numbers from Figure 9-6 will be the new UAC of this thesis, and the one created for Aker BP.

9.4. Use of New Reference Case

All simulations for seal #2 will be run against the new Aker BP UAC (11.1 kg/year for the liquid one-phase model and 0.29 kg/year for gas one-phase model)

9.4.1. Liquid One-Phase Model

As mentioned earlier the one-phase liquid model is the model that should be considered in this thesis, because these are the permeabilities with the highest data confidence.

Planning Phase on Annulus

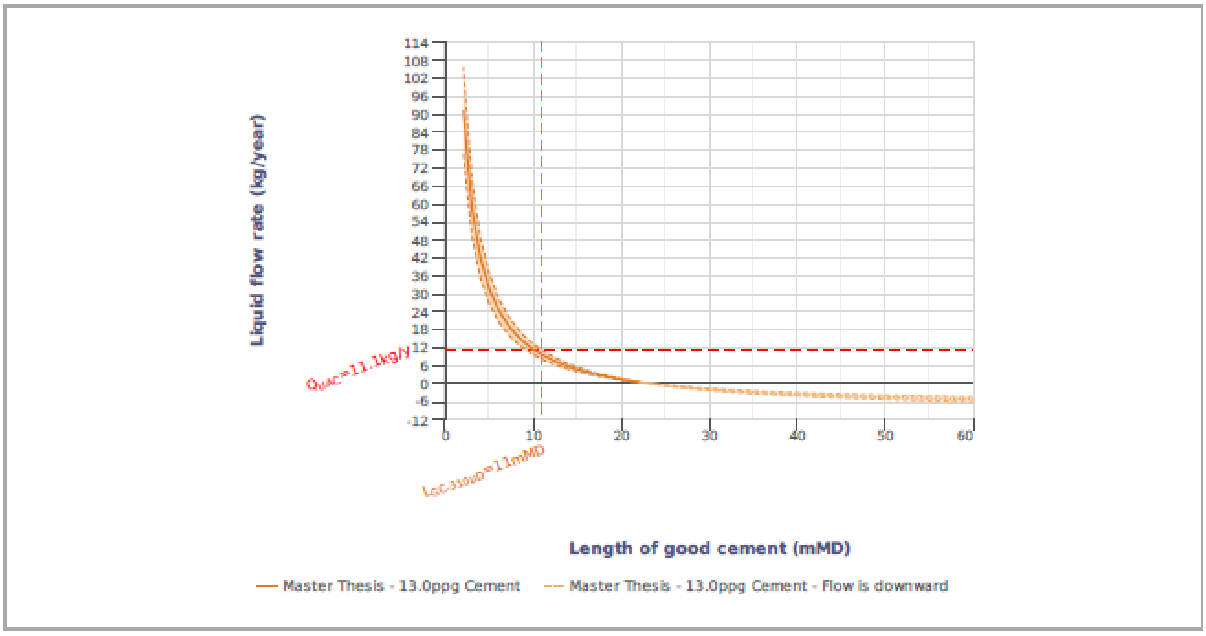

Figure 9-7: Liquid model planning phase on annulus simulation [67]

From Figure 9-7 it can be seen that a 11 mMD cement barrier of the actual cement in place, is equivalent to the 30 mMD of the reference case. The same trend as for the simulations of Chapter 9.2 can be seen in the figure. As these simulations are based on a worst-case scenario, a turn of the flow direction might happen before this length resulting in an even lower upwards leakage than displayed here.

Planning Phase on Plug

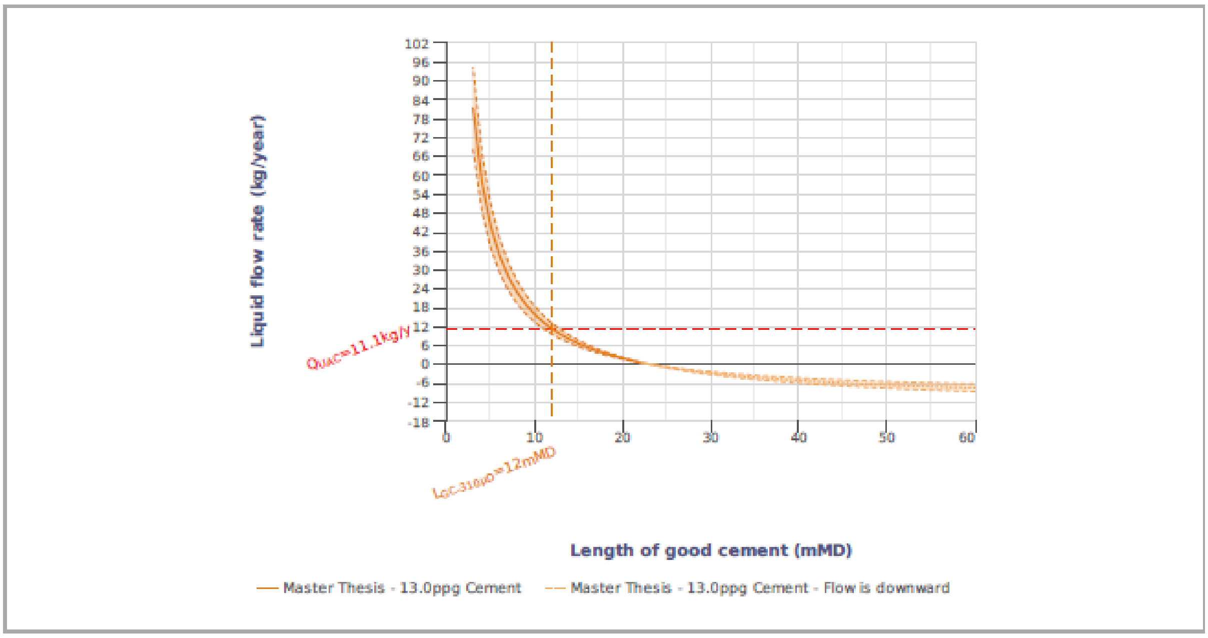

Figure 9-8: Liquid model planning phase on plug simulation [67]

According to the simulation behind Figure 9-8 13 mMD of internal cement will be equivalent to the reference case. However, it is worth noting that this cement is not already in place, and by adding a cement of better quality, this length can be reduced.

Dispensation Request

	Uncertainty: -16%		**Master Thesis - 13.0ppg Cement (310;1.11 µD)**		**Uncertainty: +16%**	
	1 st barrier	**2 nd barrier**	**1 st barrier**	**2 nd barrier**	**1 st barrier**	**2 nd barrier**
L_{GC} (mMD)	1	29	1	29	1	29
Top depth (mTVD)	363.6	-	363.6	-	363.6	-
Q (kg/y)	-53.3	-1.55	-63.45	-1.84	-73.6	-2.14

Figure 9-9: Liquid model dispensation request simulation [67]

When running the dispensation request menu for the available interval of 30 mMD, the most interesting numbers are in the column to the right, where the worst-case scenario results are displayed (when flow is upwards). In this case, the first barrier needs 1mMD to comply with the UAC. This leaves 29 mMD to be used as a secondary barrier, and a resulting downwards flowrate of 2.14 kg/year which assumes that the primary barrier has failed completely. For these simulations, the flow is downward for both the 1 mMD primary barrier and the 29 mMD secondary barrier because the lengths are calculated from the bottom with hydrostatic pressure from fluid on top (see Chapter 7.2.3.3).

A dispensation request for the use of 30 mMD for two barriers is in accordance with the simulations.

9.4.2. Gas One-Phase Model

Even though the confidence in the gas permeability results is not very high, the simulations are run. However, they are not used in the present work.

Planning Phase on Annulus

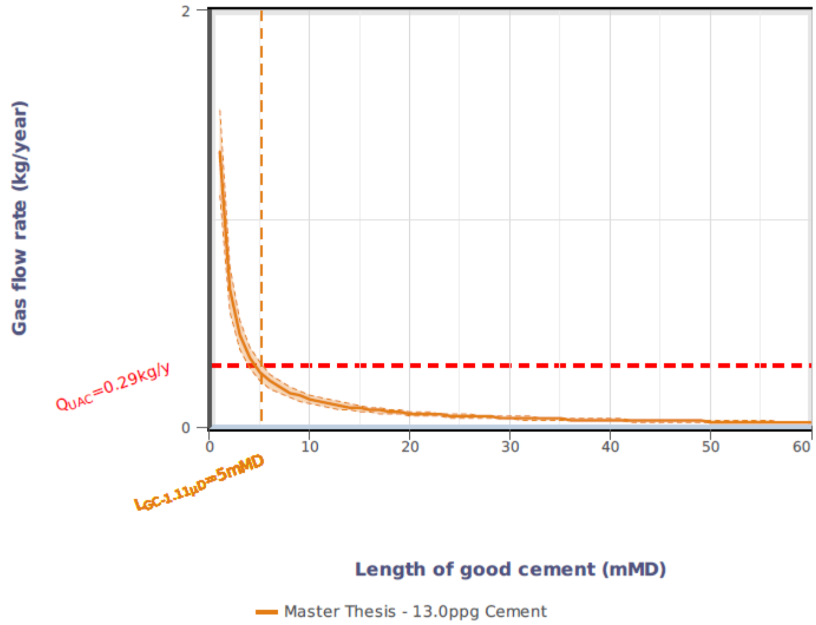

Figure 9-10: Gas model planning phase on annulus simulation [67]

From Figure 9-10 it can be seen that a 5 mMD interval of good external cement will be enough to keep the leakage rate below the UAC of 0.29 kg/year.

Planning Phase on Plug

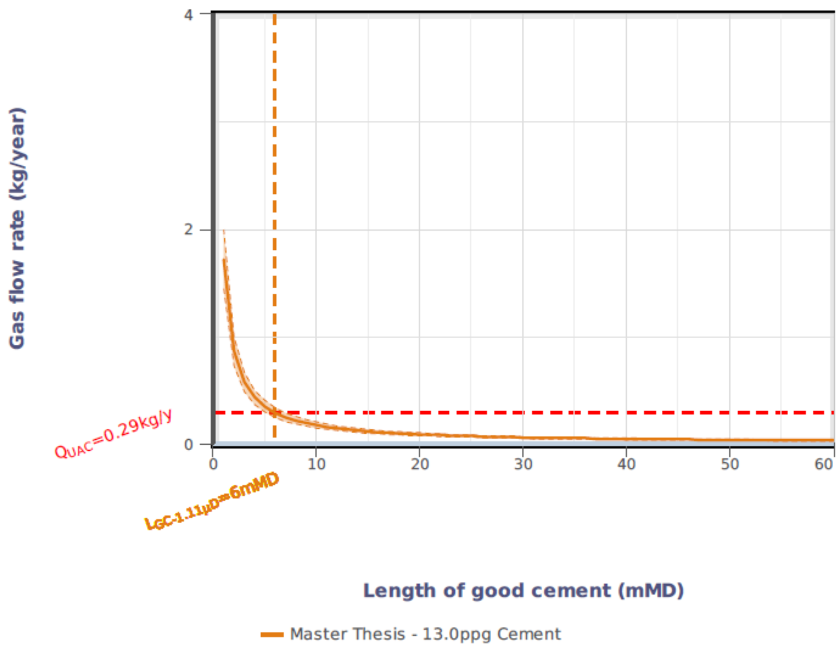

Figure 9-11: Gas model planning phase on plug simulation [67]

For an internal cement plug, the minimum length of good cement to achieve a leakage rate below the UAC is 6 mMD with the use of the same quality cement as the external.

Dispensation Request

	Uncertainty: -16%		Master Thesis - 13.0ppg Cement (310;1.11 µD)		Uncertainty: +16%	
	1 st barrier	2 nd barrier	1 st barrier	2 nd barrier	1 st barrier	2 nd barrier
L_{GC} (mMD)	1	29	1	29	1	29
Top depth (mTVD)	363.6	-	363.6	-	363.6	-
Q (kg/y)	-0.29	0.03	-0.35	0.04	-0.4	0.05

Figure 9-12: Gas model dispensation request simulation [67]

For the use of the dispensation request menu with a cement interval of 30 mMD, and looking at the worst-case results, shows that 1 mMD will be used for the primary barrier, and the 29 mMD remaining cement will be used for the secondary barrier. The resulting flow through the secondary barrier assuming complete failure of the primary barrier is calculated to 0.05 kg/year.

9.4.3. Bi-Phasic Model

As the gas permeability is an important factor in these simulations, the simulations will be run while the results will not be considered. The Aker BP UAC for the bi-phasic model is the same as for the one-phase gas model (0.29 kg/year). In addition, the bi-phasic model is dominated by the gas permeability. The results are therefore equal to those of the gas one-phase model.

Planning Phase on Annulus

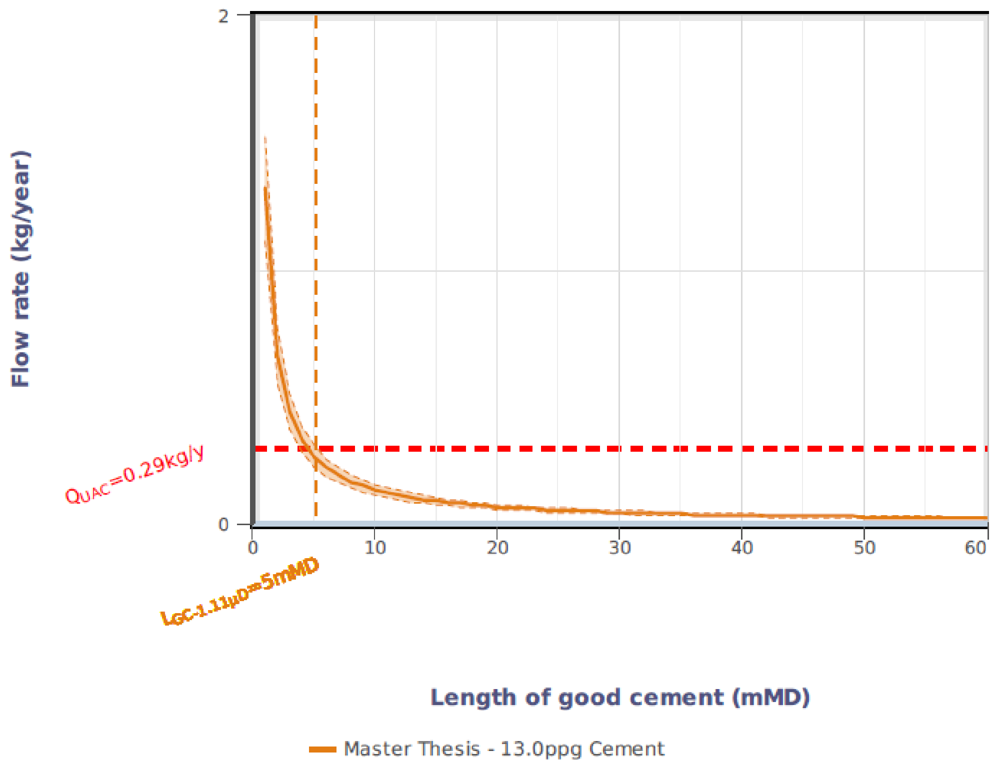

Figure 9-13: Bi-phasic model planning phase on annulus simulation [67]

Planning Phase on Plug

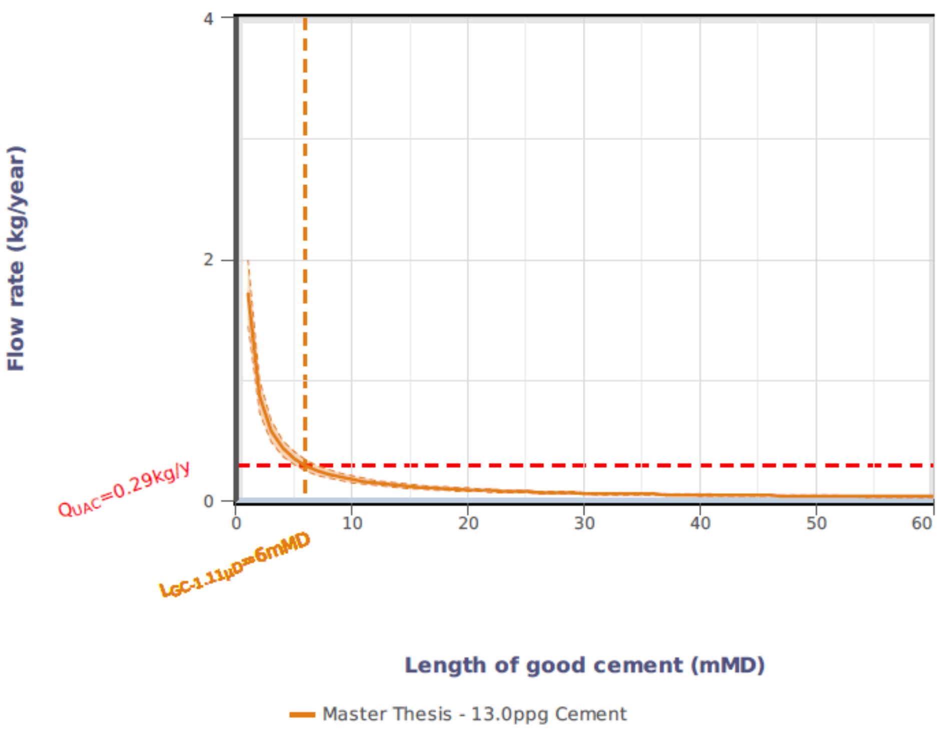

Figure 9-14: Bi-phasic model planning phase on plug simulation [67]

Dispensation Request

	Uncertainty: -16%		Master Thesis - 13.0ppg Cement (310;1.11 µD)		Uncertainty: +16%	
	1 st barrier	2 nd barrier	1 st barrier	2 nd barrier	1 st barrier	2 nd barrier
L_{GC} (mMD)	1	29	1	29	1	29
Top depth (mTVD)	363.6	-	363.6	-	363.6	-
Q (kg/y)	-0.29	0.03	-0.35	0.04	-0.4	0.05

Figure 9-15: Bi-phasic model dispensation request simulation [67]

9.5. Cement Barrier Lengths in Seal #2

From the simulations in Chapter 9.4, the cement barrier lengths for Seal #2 on this well from Valhall DP to obtain a leakage rate lower than the Aker BP liquid one-phase model UAC (11.1 kg/year) are 2 x 13 mMD for an internal plug, and 2 x 11 mMD for annular cement. With the use of the dispensation request menu for a total length of 30 mMD, these 30 mMD are accepted to be used as both primary and secondary barrier. All these simulations accept lengths below the 2 x 30 mMD required by NORSOK D-010, and are lengths obtained through a scientific risk based approach, and not from a rigid, one-model-fits-all type of requirement. In this specific case, the length for each barrier should be at least 13 mMD if the same quality cement is used for the internal barrier. If cement of higher quality is used for an internal barrier, the length can potentially be reduced to 2 x 11 mMD, and will fit within the available interval of verified cement. This way section milling is not necessary, thereby reducing risk of breaking 20” casing shoe and reducing costs.

9.6. Suggestion

This methodology calculates the minimum external cement barrier lengths to fulfill the UAC. A recommendation to reduce the leakages is to utilize the unverified cement in a well. By first calculating the necessary length of verified cement to assure a leakage below the UAC, and then complementing this length with utilization of the unverified cement, the resulting leakage rates will be kept to a minimum (see Figure 9-16). It is worth noting that unverified cement is not the same as insufficient quality cement. Unverified cement only means that the cement has not been logged or verified by other means. Even if this cement should be of insufficient quality, it will still work as a choke reducing flow. By adding an internal cement plug that covers the length of external cement calculated according to the UAC and an extra length (e.g. additional 30 mMD) at the location of the unverified cement, the total (primary barrier, secondary barrier and extra length) barrier is sure to be of best possible quality. As Portland cement is also an inexpensive material, this is also a cost-effective way to reduce leakage, where the extra barrier can act as a safety margin.

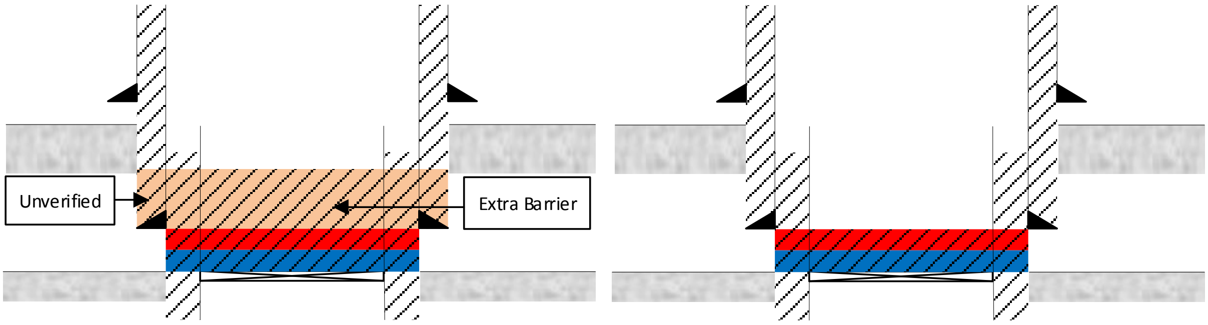

Figure 9-16: Suggested method vs. only use of leakage rate calculations

9.7. Mitigating measures

Portland cement is considered an inexpensive material [28], so if the calculated value to obtain a better isolation than the reference case requires a longer cement interval, this will in general be a good solution which increases the quality of isolation from today's standard. However, if the other barrier elements are not able to support the increased length (e.g. the window for placing the set of barriers is too short), other mitigating measures should be considered. Some mitigating measures are suggested below.

9.7.1. Alternative Materials

If a certain well or location is prone to a specific condition, alternative material (e.g. Barite plug, resins, bismuth, sandaband etc.) fit for those conditions could be considered (e.g. ductile materials should be considered in areas with movement).

9.7.2. Combination of Materials

A combination of different barrier material with different modes of failure, should increase the overall quality of the barrier. If a barrier is exposed to conditions that will normally mean failure, part of the barrier might withstand failure if this part is made up of material able to withstand those conditions (e.g. combination of cement with an unconsolidated plugging material should increase the probability of withstanding tectonic movement).

9.7.3. Additional verification

Another mitigating measure could be additional verification. As of now, annulus cement is either accepted, or not. As CBL can be categorized into several stages of quality (e.g. low, moderate, high), one possibility could be to utilize these groups. In a case where the CBL shows excellent bonding, this should not be compared to cases where they are adequate. Even bad cement should be considered, as it will reduce leakage.

Another method for additional verification is the use of communication testing. This is a method that has been tested and performed on wells at Valhall (see Chapter 9.7.3.1).

9.7.3.1. Communication Test

A new method performed by Aker BP in 2017 utilizes a communication test (see Figure 9-17) to verify WBE. By perforating at three depths with 30 m interval in between, and isolating the intervals (e.g.

with packers), the barrier element in the annulus can be verified. This is done by adding pressure to the middle perforation, and measuring pressure changes at the two other perforations. The 30 mMD interval corresponds to the minimum length of annulus cement in NORSOK D-010. If no change in pressure occurs, the barrier is verified. If the pressure increases at the other perforation(s), there is communication, and the barrier element is proven to have failed [44].

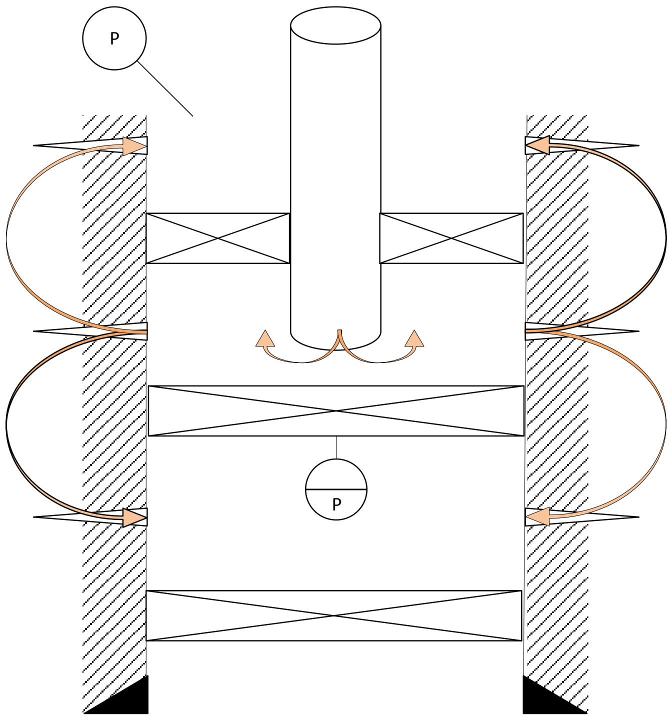

Figure 9-17: Schematic of a communication test

9.7.4. Squeeze Cementing

NORSOK D-010 accepts the use of squeeze cementing when the length of accepted cement is not long enough, but squeeze cementing could potentially also be used to decrease the leakage potential of the cement already in place. With the use of the method of this thesis, this could be performed as an alternative to section milling in places where the cement quality is not sufficient. By decreasing the flow potential of the cement, the cement barriers could be shorter with the use of the methodology presented in this thesis.

10. Conclusion

NORSOK D-010 uses a “one model fits all” philosophy when outlining the length requirements of cement barriers in a well for P&A purposes. These cement barrier lengths are based on industry practice, and not on scientific research. As every well is unique, and the conditions extend from deep HPHT to shallow LPLT wells, a fixed length of cement might not be the best approach. In an effort to take the well conditions into account, regulations from Texas (USA) and Alberta (Canada) require longer cement lengths for barriers in deeper wells.

Another alternative has been presented by Godøy et al. [1], where a risk based approach to cement barrier lengths has been used. Here, leakage rates through a barrier fulfilling requirements is used to set an Upper Accepted Case (UAC). When estimating leakage through another barrier, the corresponding cement lengths for the UAC can then be obtained, and will be the minimum cement length that should be accepted. Some barriers will need a longer length of cement than the 2 x 30 m of NORSOK, while other will need less and still have the same leakage rate.

At Valhall, the interval containing suitable formation for barrier placement in Seal #2 has a verifiable length of less than the 2 x 30 meters required by NORSOK D-010, because cement behind the second casing string is not easily verifiable. This seal covers shallow zones in the overburden at Valhall that are hydrostatically pressured in a low temperature regime. In this thesis, the methodology of Godøy et al. [1] was applied to the shallow barrier (seal #2) on Aker BP’s Valhall DP P&A project, and showed that shorter barrier lengths could be accepted without the need for further costly remediation.

Because the data used for setting the UAC in the study from Godøy et al. [1] comes from another operator on the NCS, where Aker BP has little or no control over the inputs, an alternative reference case has been created for Aker BP in the present thesis. This reference case is based on an accepted barrier covering the reservoir at Valhall. Although it is not the best approach for every operator to have their own reference case, operators will be held accountable for the wells they leave behind. It is therefore crucial to have confidence in the data.

When applying this methodology with the use of Simeo WellCem, a Darcy’s law based simulation program for estimating leakages, it has been shown that the conditions of Seal #2 fulfills the UAC from both the well in the Godøy et al. [1] study, and the UAC defined for Aker BP. In these simulations, the liquid permeability for the shallow verifiable cement is gained from testing, and the permeability of the Aker BP reference cement is taken from literature. This methodology ensures that the cement lengths are based on a scientific risk based approach, and not on common practice with no control over the resulting leakages.

When calculating flowrates through external cement, only verified cement is considered. This means that the calculated leakage rates are higher than what will occur because all cement (verified or not), will work as a choke, and thus reduce leakage.

Behind the 20” casing in the Valhall DP wells, there is a significant interval of unverifiable cement. Unverified cement is not the same as insufficient quality cement, and as this cement is of higher density than the verifiable 13 3/8” casing cement, the quality could be better. Even if the cement is of insufficient quality, it will still work to reduce the total leakage. Therefore, a good approach will be to find cement lengths that correlate to the UAC, and add an internal cement plug over the interval of the unverified cement (see Figure 10-1). This way, an extra safety margin is set and the leakage is ensured to be significantly lower than the accepted refence case.

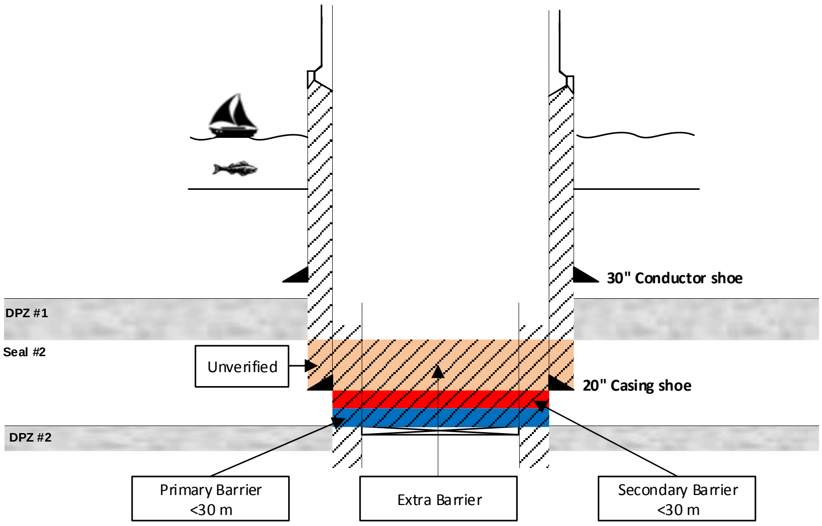

Figure 10-1: Suggested method

10.1. Recommendation for Further Work Based on this Thesis

Below are some suggestions on future work that could be conducted:

- Because permeability is the most important factor for these calculations, reference case cement should be extensively tested. Permeability values should have an experimental basis and not be assumed. More extensive permeability testing of actual cement found in wells will ensure that the data confidence is higher, and thus improving the basis of this methodology, and the modelling results. Future testing should include the effects of micro-annuli/de-bonding and other cement defects. Because gas migrating upwards in a well is most likely to encounter water-wet cement, methods for testing permeability of gas through a water-wet cement should also be investigated.
- Poorly of moderately bonded cement above the barrier that one tries to verify will work as a choke, and the possibilities to include this in the modeling should be investigated, as it will give a more realistic picture of the situation, and the occurring leakage rates.
- In this thesis, the focus has been on one-phase liquid flow modeling as the gas permeabilities had a significant spread. Bi-phasic modeling is closer to what will happen and should be investigated. To do this, good quality, reliable data regarding the liquid and gas permeability must be available.
- Cement was the only barrier material considered in this thesis. However, the risk based methodology described in the present work could be used for barrier material other than cement to further describe barrier length requirements.
- Further, it is also recommended to test other leakage simulators (e.g. IRIS leakage calculator), and check if they are in alignment with Simeo WellCem. Software including micro-annuli calculations, and probabilistic based software should be tested, as they have not been investigated in this thesis. Similar to weather forecasting, a multitude of different models may provide a better estimate of the leakage rates one could expect.

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