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Casing Design Evaluation for Water Injectors at Valhall

Master Thesis

By

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Acknowledgements

Abstract

The Valhall field is the largest field that BP operates on the Norwegian Continental Shelf, and is one of the most well known high porosity chalk fields in the Southern part of the North Sea. During many years of oil production, there has been compaction of the reservoir. The current casing design at Valhall has developed with time as the field has matured, and is affected by several considerations like casing shear in the overburden due to subsidence, non-uniform loading in the reservoir due to chalk production and compaction.

The main objective of this thesis was to develop options that could be included in the current casing design, to guarantee a higher injection pressure than is available today at the Valhall field. The current design is limiting the maximum injection pressure in the water injectors, and the main factor is the use of $9^5/_8$" drilling liner combined with a cement squeeze job through a C-Flex port collar. This cement job is not approved as a barrier element as required by NORSOK. The injection pressure is today limited by the strength of the $13^3/_8$" casing shoe, which is lower than desired.

The study involves reviewing BP's casing design manual, the current casing design on Valhall, the special requirements for Valhall, and investigating several technologies that could provide potential solutions to the barrier challenges on Valhall.

The recommended option is to include the External Sleeve Inflatable Packer Collar (ESIPC), Cement Assurance Tool and the C-Flex in the $9^5/_8$" drilling liner. The ESIPC would provide a good cement job in the liner annulus, as it would enable returns to be observed during the cement job, providing evidence that there is a cement column behind the drilling liner by a cement bond log. The C-Flex is included to make it possible to perform a cement squeeze job through the C-Flex additionally to the ESIPC or in worst case alone if the ESIPC fails. The Cement Assurance Tool is just an extra safety in case the cement around the liner would contract and make a micro-annulus, which could create a possible leak.

This option would most likely provide a barrier element according to NORSOK. This barrier element is very important to be able to increase the injection pressure at a wanted level, which is approximately 6,300 psi.

At present time, the ESIPC is not strong enough to be included in a drilling liner. It has to be reinforced and tested before it could be included in the drilling liner to be able to withstand the large forces acting on the tool. The corresponding dual bottom-top wiper plug set has to be reinforced as well, because the plug set would be exposed to large forces during the losses, and when it is set inside the ESIPC.

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1 Introduction

The Valhall field is the largest field that BP operates on the Norwegian Continental Shelf, and is one of the most well known high porosity chalk fields in the Southern part of the North Sea. During many years of oil production, there has been compaction of the reservoir. The current casing design at Valhall has developed with time as the field has matured, and is affected by several considerations like casing shear in the overburden due to subsidence, non-uniform loading in the reservoir due to chalk production and compaction.

The Valhall field was unofficial discovered in 1969 when an exploration well hit oil in the thin south flank, and official discovered in 1975 when a well found the large chalk reservoir containing oil in the thick part of the crest. The production was started during 1982 and is expected to continue until 2,050.

The main reservoir formation is the Tor formation, and the true vertical depth is around 2,450 meters TVD RKB at the crest, and approximately 2,650 meters TVD RKB at the flanks. There is also a significant volume of free hydrocarbons in several layers between the top of the Tor formation and the seafloor due to seal leakage during geologic time.

The current casing design is not optimizing the long term recovery from the Valhall field. The design is limiting to the maximum injection pressure in the water injectors. The main reason for this limitation is the use of the $9^5/_8$" drilling liner to drill depleted Tor combined with a cement squeeze job through a C-Flex port collar approximately 40 meters above the liner shoe. This cement job is not approved as a barrier element according to NORSOK. The injection pressure is then limited by the integrity of the $13^3/_8$" casing shoe, which is lower than desired.

The main purpose of this thesis is to develop potential options that could be included in the current casing design, to allow a higher injection pressure than is possible today without weaken the integrity of the well. The desired injection pressure is approximately 6,300 psi. During this thesis, the aim was to obtain a better understanding of the Valhall field, the current casing design and the reason for this design.

Several technologies from several companies have been investigated. In cases where the technology itself did not present a potential solution themselves, they have been combined with other technologies, and evaluated.

The first part of this thesis, Chapter One, introduces the background and the current status of the Valhall field, and the main purpose and structure of this thesis. The second part, Chapter Two, describes the Valhall field and the water injection process, experiences on Valhall, and general info about casing design. The third part, Chapter Three, investigates different technologies that could be a potential solution to the barrier challenge on Valhall. The fourth part, Chapter Four, investigates current operational procedures, different combinations of the different technologies, and how they can be included in the casing design. The fifth part, Chapter Five, discusses, evaluates and ranks the different options. Several proposals were rejected, and the reasons for this are discussed. This part also shows how to include the recommended option in the current casing design and what further work needed to make it possible. Chapter six, summarize the conclusion and recommendation for how to include the recommended option in the current casing design on Valhall.

2 Theory

2.1 Facts about Valhall

BP's largest field in the Norwegian Sector is Valhall, which is located approximately 290 kilometres from the Norwegian shore in the south western corner of the Norwegian Continental shelf. As showed in picture 2.1.1, the Valhall field is located close to the large Ekofisk field operated by ConocoPhillips.
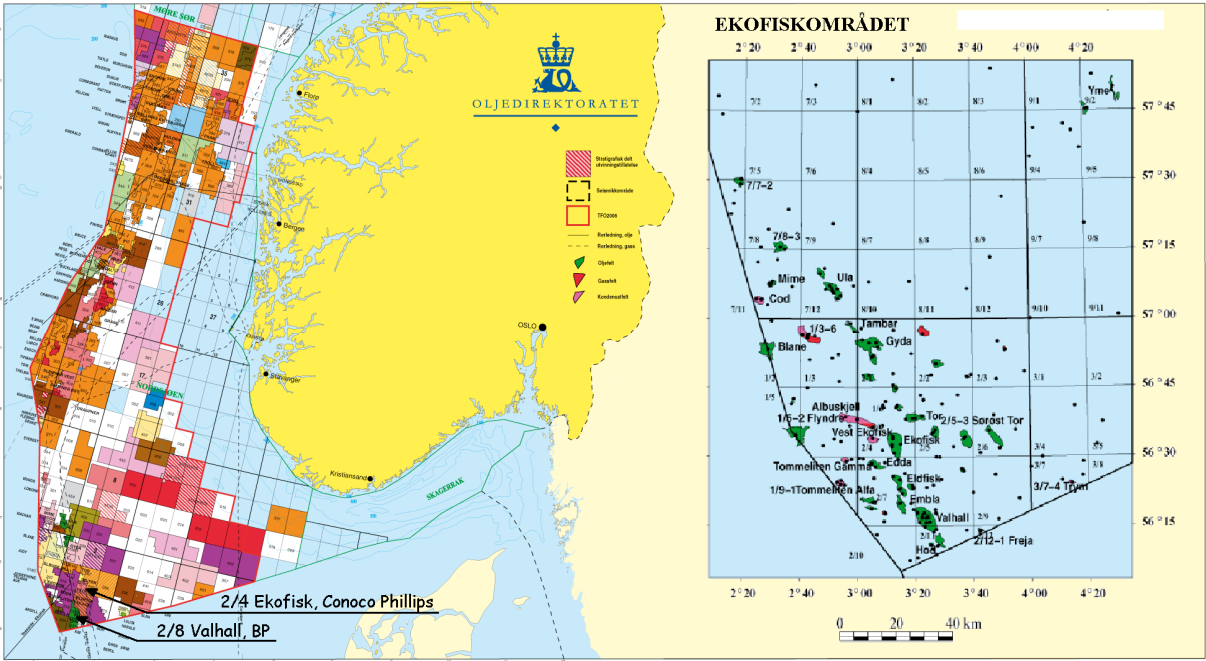
Figure 2.1.1: Map of the Norwegian Continental Shelf, with Valhall and Ekofisk located in the corner. Show also a detailed map of the Ekofisk area, where Valhall and Hod is presented. Modified from [NPD, 2009]

The Valhall field was unofficially discovered in 1969 when an exploration well hit oil in a thin part of south flank, and officially discovered in 1975 when a well encountered the large chalk reservoir containing oil in the crest, [Rasen, 2007]. During 1981, three platforms, QP, DP and PCP were installed in the Valhall field. Production at Valhall started October 1st 1982 and is expected to continue until 2050. The water depth at the Valhall field was approximately 69 meter in the beginning, today the water depth is approximately 75 meters. The reservoir had an estimated recoverable reserve of 247 million barrels of oil when production started. The field has already produced more than this and the oil in place have increased to approximately 3 Billion barrels of oil.

The licensees at Valhall are BP Norge AS, Hess Norge AS, Norske Shell AS with 28.09 % each, and Total E&P Norge AS with 15.72%. The license period endures to 2028.

The Valhall complex consists of five platforms connected together as showed in figure 2.1.2. These platforms are the Quarters Platform (QP), the Drilling Platform (DP), the Production and Compression Platform (PCP), the Wellhead Platform (WP), and the Injection Platform (IP). In addition two Flanks Platforms are installed approximately six kilometres north and south of the Valhall complex.

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Figure 2.1.2: Show the main part of the Valhall field. [BP, 2009 e]

The Quarters Platform has accommodations for approximately 208 people. The Drilling Platform lies between the Quarters Platform and the Production Platform, and has 30 well slots used for waste injection and oil production. The Production Platform is build to process 168,000 barrels of oil and 350 million cubic feet of gas per day. The oil production is piped to 2/4-J at the Ekofisk Centre and goes to Teesside in England. The gas is transported directly via Norpipe to Emden in Germany. The Production Platform processes oil and gas that comes from the Hod field as well. The Wellhead Platform was installed in April 1996 and started the production of oil in June the same year. This platform has 19 well slots. The Injection Platform is linked to the Wellhead Platform, and has 24 well slots. This platform has integrated topsides with water injection facilities, seawater and produced water treatment facilities and power generation. The IP derrick can skid on beams from the IP to WP, including the mud mixing module, and allows for drilling and maintenance of wells on both platforms. The Injection Platform is linked to an Onshore Operation Centre (OOC) in Stavanger via a fibre optic line, providing the same data as they have offshore and ability to involve more engineers to solve issues, enhancing safety and requiring fewer people offshore. The Valhall Flank Platforms consist of two identical unmanned wellhead platforms, and each of them is equipped with 16 drilling slots. Both the North Flank Platform and the South Flank Platform is located, as mentioned, about six kilometres from the existing Valhall facilities where the streams are processed. Picture of one of the Flank Platform is showed in figure 2.1.3.

Figure 2.1.3: One of the flank platforms at the Valhall field. [BP, 2009 f]

The Valhall field has a central location, and with the new planned Quarter- and Production Platform makes it possible for the Valhall complex to possibly host several other fields in the future.

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2.2 Water Injection

Water injection on Valhall first started in January 2004 in one converted WP platform producer, and continued with a second producer put on injection in 2005. Both were located north and north-west of the central crest area and several Injectors has been drilled from IP the last years.

Injection of water has been proved to be one of the best economical methods for managing the reservoir. The thought behind the water injection is to maintain or increase the reservoir pressure, and the result is enhanced production of hydrocarbons. The water injectors are often at the flanks of the reservoir to be able to displace the oil from the reservoir and push it towards the producers. Another benefit with water injection is the reduced place environmental impact when reinjection of treated and filtered produced water is taking place.

Every water injection system has to be custom made for the specific reservoir it should be used in. There is several design factors that has to be considered when designing a water injection system, some of them are how large the injection pressure and the flow rate should be. These factors determine the type of pump and how many that is needed taking into account that changes may occur during injection. Another thing is what kind of water source that should be used, reinjection of produced water or seawater is typical offshore water sources. There are different benefits by using produced water and seawater as a source compared to each other. The produced water reduces the potential of causing formation damage due to incompatible fluids, but there is still a chance of scaling or corrosion in the injection flowlines or pipes. This water is containing hydrocarbons and solids and has to be disposal in some way.

The volume of the produced water are never sufficient enough to replace all the production volumes, additionally water sources must be used, but this mix will increase the chance of scaling. The most convenient source offshore is seawater, but filtering, deoxygenating and biocideing is most commonly required.

Other things that has to be considered when designing a water injection system is different physical factors like deck loadings, noise, fire escape routes, and different equipment utilities as diesel, gas and electrical.

A typical Water Injection system is where the water from the source arrives to a storage tank, as showed in figure 2.2.1. The water is going through a coarse filter and a polishing filter to clean the water as much as possible, before it is stored in another tank. The filtration system is depending on the purpose of the water injection system and the quality of the injection water. Before the water is going into the injection pumps and through the wellhead, injection of necessary chemical into the water is performed. All important parameters like pump speeds, water quality, temperature, flow rates and what kind of chemical that should be injected into the water is controlled and observed through control devices. Typical chemical that is being injected is corrosion inhibitor, chemical mixture, biocide, and oxygen scavenger and surfactant.
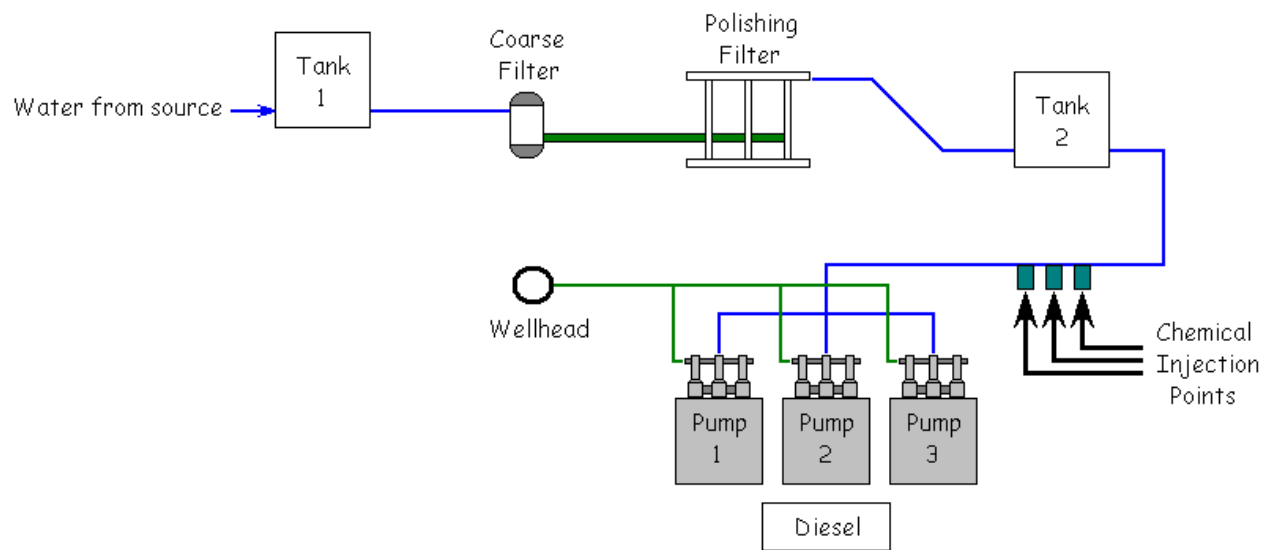
Figure 2.2.1: Show the principle of a water injection system. Modified from [Halliburton, 2009 a]

2.3 Experiences and Observations on Valhall

2.3.1 Seismic data; Gas effect on Valhall

The first seismic made of Valhall, indicated that the reservoir potentially was a large ring without something in the middle, and the first well was drilled along this ring. Later, it became clear that the reason the seismic did not shown anything in the middle, was because of a large gas cloud in shallower layers that resulted in misinterpreted seismic, as showed in figure 2.3.1.1. This was the most obvious feature in the seismic data from the Valhall field. There exists gas in different permeable layers from 400 meters TVD and down to the main "gas cloud" at approximately 1,400 meters TVD. Because of this gas, there has been a challenge to get a good interpretation of overburden and the reservoir seismic in the crest of the field, [Haga, 2009] and [Kristiansen, 1998].
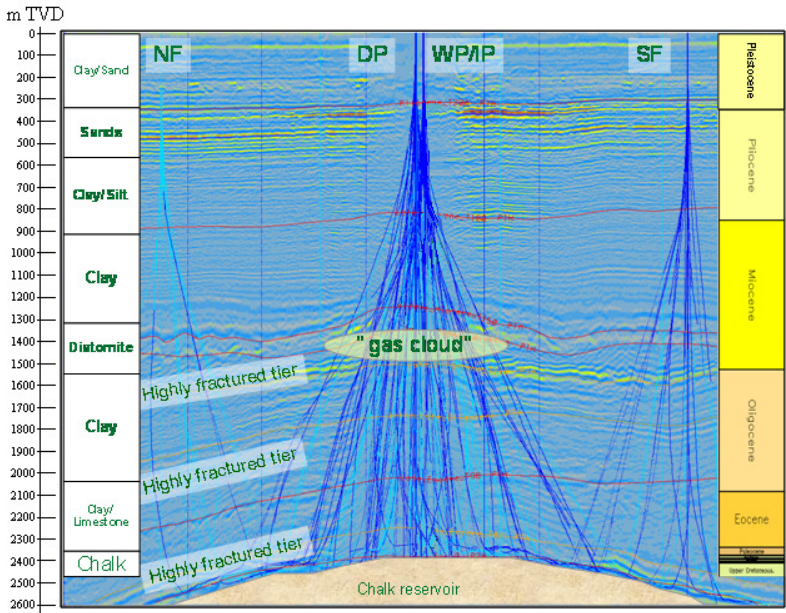
Figure 2.3.1.1: Main gas-cloud identified below Valhall IP prior to platform installation. [Haga et al., 2008]

2.3.2 General Observations

The Valhall field is an initially over-pressured, under-saturated Upper Cretaceous chalk reservoir. This reservoir is located in the central graben in the Norwegian Sector of the North Sea at approximately 2400 meters TVD subsea.

The chalk at Valhall is weak, and a combination of the in-situ effective stresses in the formation and the low mechanical strength of the reservoir chalk, has resulted in chalk production. Because of pressure depletion, the chalk has lost a significant part of its initial porosity resulting in compaction of the reservoir and associated subsidence of the overlaying formations.

Reservoir compaction above a certain limit will eventually result in casing deformation and in some cases casing collapse. This is in cases where standard well designs are used. Seafloor subsidence is a large potential risk to pipelines and platform constructions.

In spite of all the challenges associated with the hydrocarbon production from the soft chalk reservoir at Valhall, the positive effects of the compaction is the increased reservoir energy that outweigh the negative consequences of it.

The reservoirs consist of two oil bearing formations, Hod and Tor. The Tor formation contains roughly 66% of the oil, and the chalk has a purity of 95 – 98% calcite, high oil saturation above 90%, and porosity up to 50%. The effective overburden stress in the Valhall formation was around 500 psi at discovery, with a pore pressure of 6,500 psi and an overburden pressure at 7,000 psi. Currently, the reservoir pressure in the Tor formation in the crest has decreased to 2,500 psi, and even lower in some places, which has resulted in problems with large losses when drilling into this formation, [Kristiansen, 1998].

Since the production started in 1982, the seabed subsidence has reached approximately 6 meters at the platform complex, and many wells on Valhall have been sidetracked due to severe pipe deformations. Most of these deformations have occurred in the overburden according to collected data. Compaction of the reservoir and subsidence has caused casing deformation in many other fields and is a known challenge worldwide, [Bruno, 1992] and [Schwall and Denney, 1994]

The first casing deformation in the reservoir at Valhall happened almost instantaneously as a result of compaction near the wellbore and chalk production. The first casing deformation in the overburden was experienced in 1986 when the seabed had subsided less than a meter, and the result of this was a sidetrack.

Valhall caliper data indicates that most of the casing deformations occur close to the reservoir, within the first 100-200 meters TVD above the top of reservoir, see figure 2.3.2.1. Caliper logs have shown deformation as shallow as 500 meters TVD above the top of reservoir. The mechanical properties from core samples or logs do not indicate a specific problem with the formation. It is therefore believed that the main relationship between the casing deformations and the formations where the deformations occur may be change in stress due to the reservoir compaction below. This will result in "slip on plane of weakness as a result of reduction in normal stress on the weak plane, and changes in shear stress across it as a result of subsidence", [Kristiansen, 1998]. A well failure may happen due to cross-sectional collapse or buckling failures in the reservoir as well.
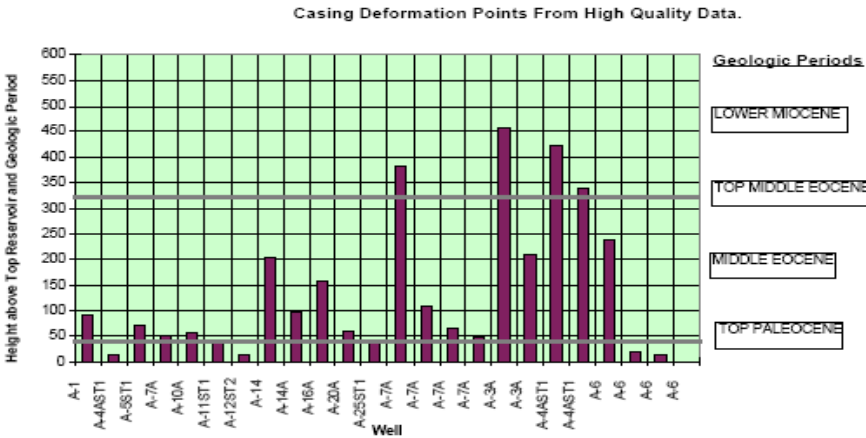
Figure 2.3.2.1: Casing deformations from calipers at Valhall. Location relative to top of reservoir and the well the deformation was detected in. [Kristiansen et al., 2000]

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The data from the caliper show that several deformations are located in the some of the wells.

From micro-seismic monitoring performed at Valhall, it seems that there are different stress levels in the formations, and the shear loading on the casing might follow these observed micro-seismic trends. The shear stress is quite constant in the shallowest layers, but at the closest layer above the reservoir the shear stress is much higher, as illustrated in figure 2.3.2.2. The displacement gradient of the formation increases corresponding with the shear stress, which means that the displacement are largest between 2,000 meters and 2,400 meters TVD where most of the casing deformations and collapses are observed.
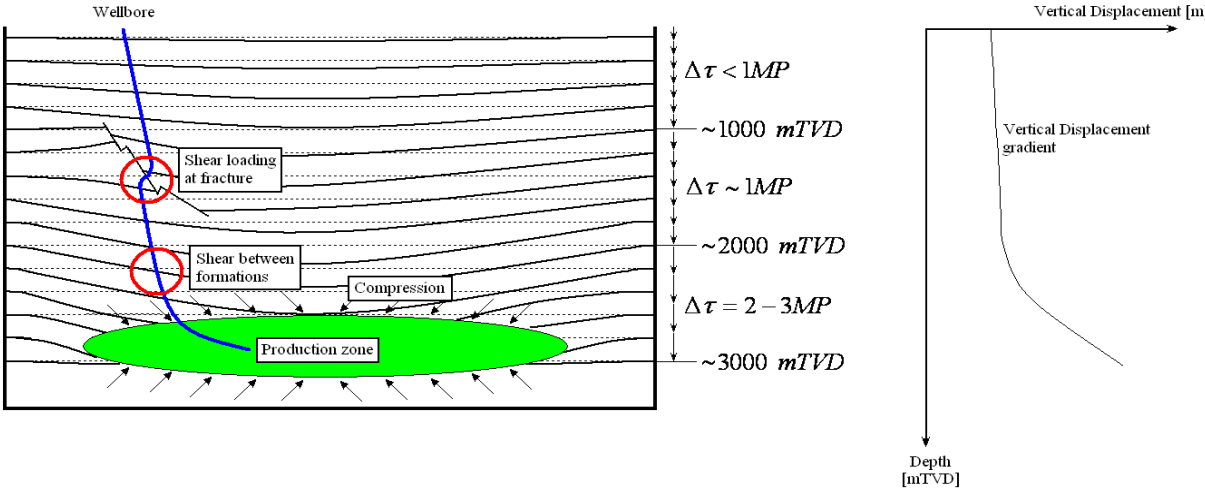
Figure 2.3.2.2: Illustrate the different shear stress levels in the formation at Valhall. The values are typical values from the geomechanic full field model, and the corresponding vertical displacement gradient. The vertical displacement is largest at the top of the reservoir. Show also a well going through a fault where large shear loading are located and the possibility for a casing deformation is high.

2.3.3 Casing Deformations

A casing design is basically based on the maximum potential load conditions during stimulations and pressure depletion, during installation of the casing, and due to unexpected leaks. Typical design loads are; collapse, burst, tension and triaxial loads. Through several years there have been reported several cases of lost casing integrity. It is not only Valhall that has this concern, many other different cases from all around the world are observed. These instances involve reservoir compactions and subsidence, like Valhall, solids production, tectonic loading, salt flow, earthquakes or large thermal fluctuations. [Kristiansen et al., 2000]

The root cause of deformation in the pipes in an oil and gas well is the volume change in the surrounding rock around the wellbore. This change of the rock bulk volume is a response to stress changes resulting from pore pressure and/or temperature changes introduced to the rock mass during production or injection. If the cap rock or the reservoir is weak enough, these volume changes may be enough to cause casing deformation.

Changes in stress arise from changes in the pore pressure. The pore pressure is decreasing due to production, and increasing due to injection.

Pore pressure and total stress are connected through the effective stress law [Kristiansen et al., 2000]:

$$S = \sigma - \alpha P ,$$

(2-1)

where σ is the total stress, the P is the pore pressure, and α is Biot's constant.

The Biot's constant is given by:

$$\alpha = 1 - \frac{K_{fr}}{K_s}$$

(2-2)

where K_{fr} is the bulk modulus of the rock framework, and K_s is the bulk modulus of solids.

One can often set $\alpha = 1$ in the case of weak rock, soil and high porosity, $K_s \gg K_{fr}$.

Because of the changes in effective stresses in the rock, volumetric deformation in the rock is given by:

$$\Delta \varepsilon_v = \frac{\Delta S}{M}$$

(2-3)

where $\Delta \varepsilon_v$ is the change in volumetric strain and M is the rock deformation modulus.

For elastic deformations, M_e has a constant value that gradually reduces when the rock start behaving more plastically, M_{e-p}. At a certain stress level, the value will have a reduced value M_p, and this value will start to increase again due to work hardening effects. Many rocks show strain rate dependent deformation behaviour in addition to plastic and elastic strain, which is given by:

$$\varepsilon_v = \varepsilon_{ve} + \varepsilon_{vp} + \varepsilon_{vp(t)}$$

(2-4)

where ε_{ve} is the instantaneous elastic volumetric strain, ε_{vp} is instantaneous plastic volumetric strain, and $\varepsilon_{vp(t)}$ is the time dependent plastic volumetric strain.

$\varepsilon_{vp(t)}$ is often referred to as creep and can be expressed as:

$$\varepsilon_{vp(t)} = C \log \left[1 + \frac{t}{D} \right]$$

(2-5)

where C is a material constant. Thermal effects may be included through a relation given by:

$$\Delta S = \frac{E}{1-v} \alpha_T \Delta T$$

(2-6)

where E is the Young's modulus, v is the Poisson's ratio, α_T is the thermal expansion coefficient, and ΔT is the change in temperature.

These volume changes that occur in the rock, both in and outside the reservoir, will result in load re-distribution reorganization.

Since the rock most often contain fractures, faults and joints, the volumetric changes in the rock can induce slip on these weak planes, and the onset of slip on these planes is given by the Mohr-Coulomb criteria:

$$\tau_{max} = S_n \tan \mu \tag{2-7}$$

where S_n is the normal stress on plane of weakness, and μ is the frictional coefficient of the plane of weakness.

Volumetric deformations in the rock and the shear displacements on weak planes will be transferred to the casing and cement in the well. The properties of the rock, the cement, and the bond strength of the cement between the casing and the formation decide how much energy that is transferred.

The compaction of the reservoir is depending on the initial height of the rock, h_i, the compressibility of the rock C_m, and the change in pore pressure, ΔP. The compaction is given by the equation:

$$\Delta h = \Delta P \times C_m \times h_i \tag{2-8}$$

where the Δh is the compaction, this relationship is illustrated in Figure 2.3.3.1. Due to pressure depletion of the chalk reservoir on Valhall, the chalk has been compacted. Since there is a thicker chalk layer in the basin than the thin areas of the reservoir, the basin has been compacted a lot more the at the thin areas. Because of the different compaction between the basin and the thins, large faults have been re-activated around the crest. Well located in the area of these faults are most exposed to deformation.
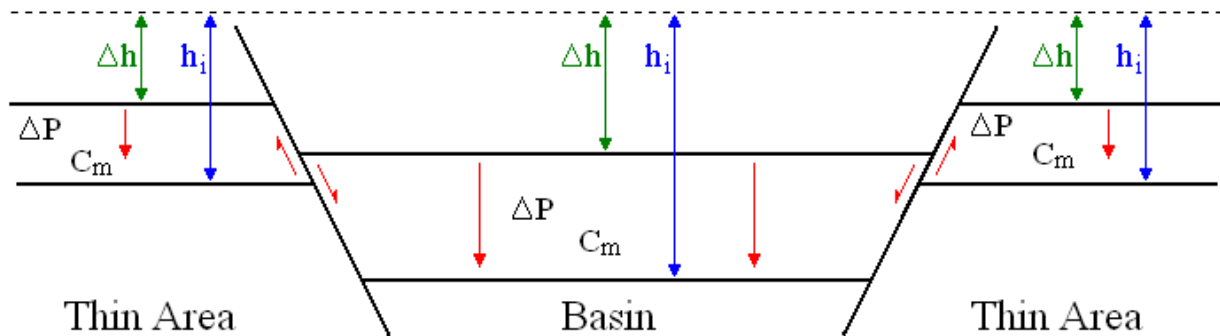
Figure 2.3.3.1: Show the relationship from the terms in equation 2-8, and why large faults around the crest of the Valhall reservoir are re-activated where the casing deformation often occurs.

The most likely casing deformations in an oil and gas well are believed to be tension, bending, column buckling, and cross sectional crushing and shear. Some of these deformation modes may occur simultaneously.

For the new wells on Valhall today, one expects casing deformation to be a part of the operational cost. In the planning of these new wells, an evaluation of how stress changes might propagate upwards from the cap-rock/reservoir interface and into the Paleocene formations will be important.

The Paleocene formations above the Tor formation is Lista, Sele and Balder, as illustrated in figure 2.3.3.2.
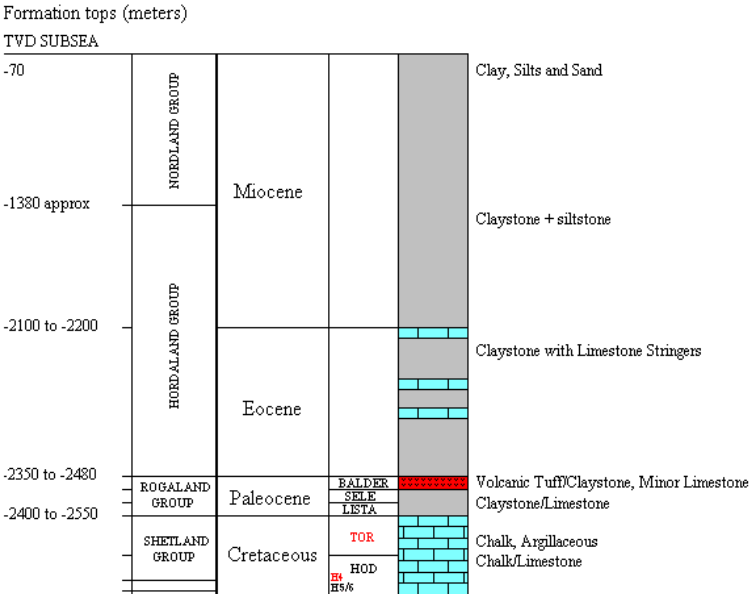
Figure 2.3.3.2: Show the lithology at the Valhall field. Modified from [Kristiansen et al., 2000]

Horizontal wells on Valhall were introduced in 1991, and many such wells have been drilled later both on the crest and the flanks of the field. Because of extension of the Valhall field and the reservoir depth, the development of horizontal wells to the flanks, drilled from the IP Platform, is a challenge. These wells requires extended reach drilling of wells longer than 7 kilometres and an inclination angle between 70 and 75 degrees through the unconsolidated and over-pressured Hordaland formation of Tertiary age. It is a large challenge drilling these long horizontal wells to the flanks from the IP Platform, and they are very expensive as well. The North- and South Flank Platforms were installed to be able to reach the flank of the reservoir with shorter wells, as illustrated in figure 2.3.3.3.
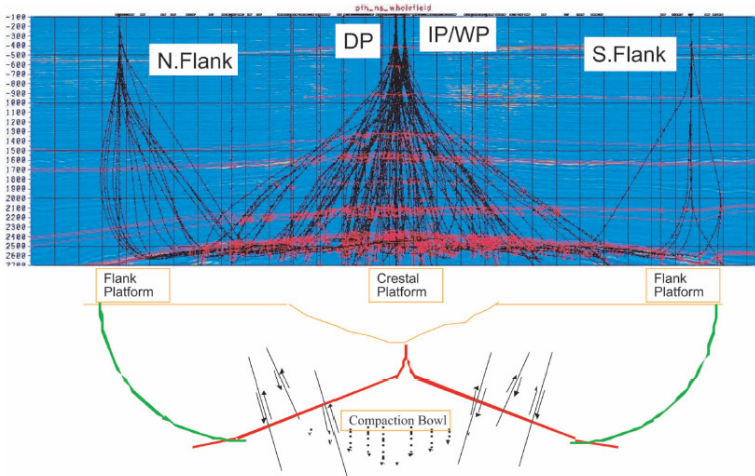
Figure 2.3.3.3: Show a cross section of the Valhall field with the two Flank Platforms with their well trajectories. The lowest figure shows an illustration of how the crest has subsided including re-activation of large faults. [Kristiansen, 2007]

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Unfortunately, a number of the wells drilled from DP and WP have failed in the overburden. That includes cemented and uncemented liners, and concentric configurations which are dual casing strings connected by a cement sheath. It is a tough producing environment on Valhall because of the large compaction during depletion, and the consequences for the casing and tubular that penetrates the reservoir. These challenges have resulted in several new completion techniques and casing design through the years.

Experiences from other fields, like Ekofisk, indicate that there is nothing to do to prevent the compaction and associated kinematics, so the best strategy is to extend the well life as long as possible with minimal addition cost.

In terms of casing deformation, the wells on Valhall can roughly be divided into four sections, like as shown in [Kristiansen et al., 2000]:

1) The production interval with perforations:
    a) Often very rapid deformations
    b) Chalk production in combination with compaction results in buckling in deviated and vertical wells.
    c) Chalk production in combination with compaction results in cross-sectional collapse in highly deviated and horizontal wells.
    d) Potential shear deformations along faults and induced hydraulic fractures during compaction or chalk production.

2) The interval between the perforations and the cap rock:
    a) This section is often left un-perforated and is used as a contingency when the top perforated interval is no longer accessible after a chalk influx.
    b) Un-perforated, this section has a relatively low frequency of deformations, especially in horizontal wells.
    c) When the section is perforated it acts as a normal production interval.

3) The section at the top of reservoir/caprock transition:
    a) The production casing is often placed as close to top reservoir as possible.
    b) Casing deformations are most frequent in this part of the overburden and can be found anywhere from top chalk to Middle Eocene.
    c) There also seems to be a relation between chalk production and casing deformation in the deeper part of the caprock.

4) The section through the shallower overburden:
    a) The deformations have a higher frequency in the deeper part.
    b) The shallowest deformation to date has been found around 500 meters above the top of the reservoir.

Some improvement strategies due to casing deformations may be:

- Use oriented perforations shot with a 180 degrees phasing at the top and bottom of the wellbore to reduce the chalk production.
- Use liner with as low D/t ratio as possible into the reservoir.
- Try to get a good cement bond between the production liner and the wellbore wall to ensure well integrity.
- Use hydraulic propped fractures to reduce pressure gradients near the wellbore, and to maintain the productivity.

It is documented by Pattillo [Pattillo et al., 1995] that an increase of the wall thickness increases the resistance of a tubular cross section to non-uniform loading. Pattillo and Kristiansen show through numerical modelling [Pattillo and Kristiansen, 2002], that casing with sufficient low D/t ratio have the ability to withstand the compaction and the associated loads from the reservoir. But use of thick walled casing will increase the difficulties regarding installation of the string, such as increased torque and drag forces, and clearance in smart well completions. Since the porosity, and therefore strength in the reservoir, varies laterally, it is the not optimal to use "one-size-fits all" standard in the well design. At the flanks of the reservoir, porosity is lower and the strength is higher.

Lack of competent cement sheath over a part of the casing circumference will speed up the stress intensity in the tubular, and negate the advantage gained by other improvement strategies. If there is no cement at the high-side of the pipe in a horizontal section, the largest stress in the pipe would be in this area, as illustrated in figure 2.3.3.4. If the D/t ratio is low enough this is not an issue.
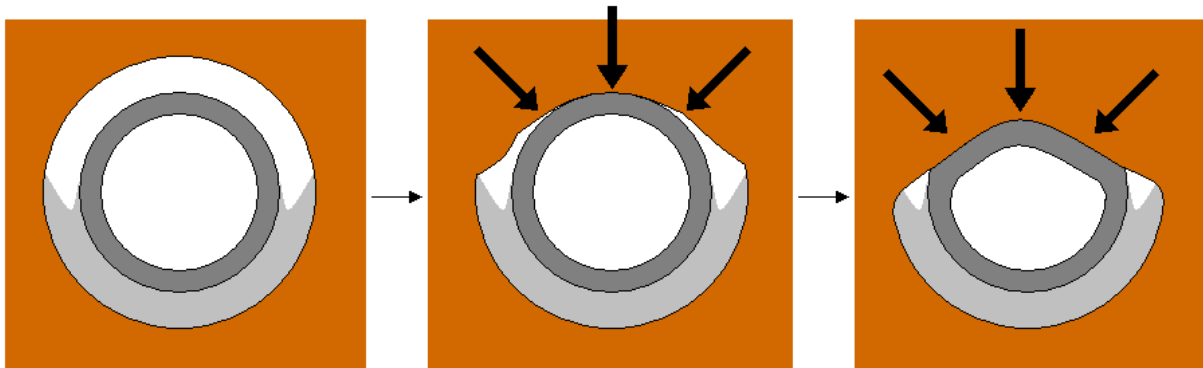
Figure 2.3.3.4: Show no cement at the high-side of the pipe, which result in compaction of the formation and deformation of the pipe in a horizontal section.

2.3.4 Ekofisk Field

The Ekofisk field has experienced casing deformations both in the overburden and in the reservoir. Nagel [Nagel, 1998] has presented a distribution of the casing deformations observed in the overburden of this field, and it indicates a relationship between the locations of the well and the compaction bowl. It is mainly in the area between the most compacting chalk in the crest and the less compacting chalk at the flanks that is the most critical position for casing deformation. The

casing deformations at Valhall has been plotted in a similar way, and it is seems not to be similar to the casing deformation at the Ekofisk field, see picture 2.3.4.1.
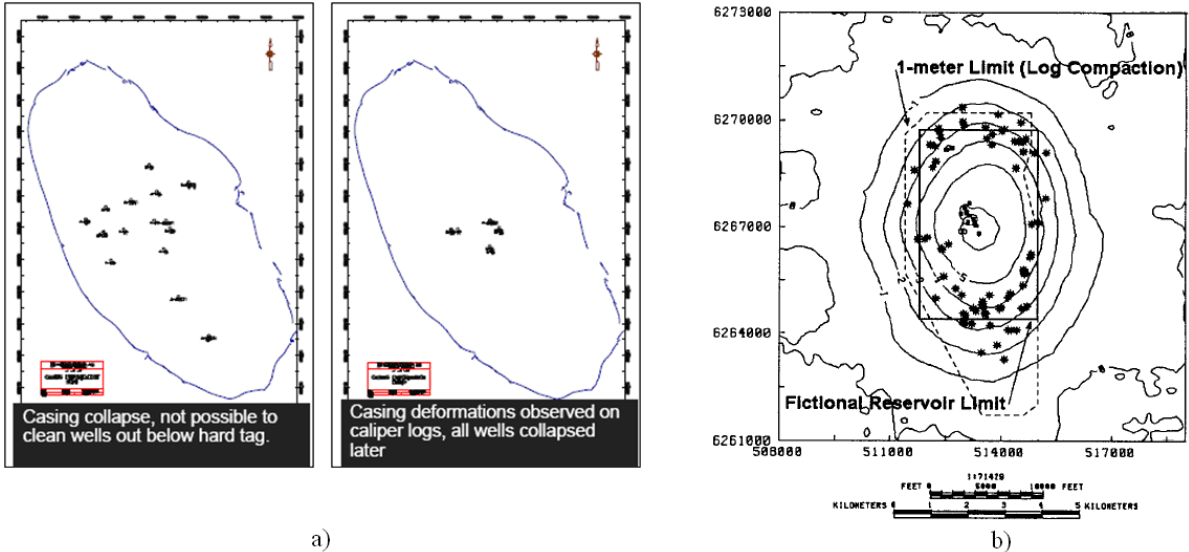
Figure 2.3.4.1: Comparison between the casing deformations at Valhall (a) and Ekofisk (b). [Nagel, 1998] and [Kristiansen et al., 2000]

The main reason is because the Ekofisk field has a quite uniform formation structure, while the Valhall field has small thicker reservoir basins inside the main reservoir, which give an uneven formation structure, as illustrated in figure 2.3.4.2. These basins also have the largest compaction due to the thickness.
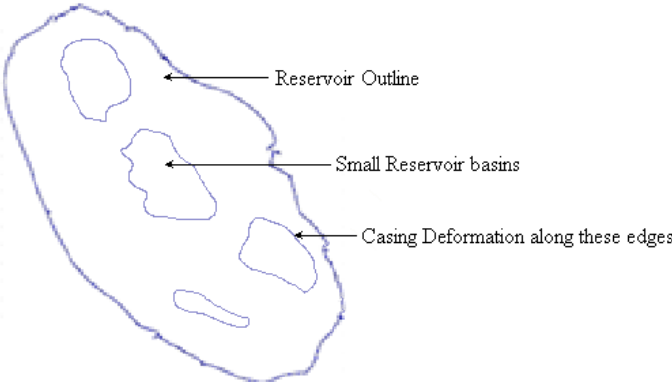
Figure 2.3.4.2: Small reservoir basins inside the reservoir outline.

The casing deformations at Valhall are usually located along the edges of the small reservoirs. The compaction could be accelerated locally close at the well during chalk production events. This compaction may direct a high strain rate on the cap-rock that surrounding the well.

Because the caprock is quite unconsolidated and soft, it is possible that a major part of the strain transfer that is happened due to a normal compaction will be slow enough to be diverging through deformations that are not localized, such as creep. However, the increased strain pulse because of

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the chalk production will not diverge through creep, but will cause localized deformations, such as slip on weak planes.

Since both Valhall and Ekofisk had problems with casing deformations in the overburden, BP and ConocoPhillips initiated a collaboration project with Centre for Frontier Engineering Research (CFER) to extend well life in the overburden. A lot of information from the Ekofisk field and the Valhall field was evaluated and their conclusions were:

- In both fields, the casing deformations were localized only across a couple of meters, see figure 2.3.4.3.
- From the analysis of the caliper data, it was suggested that the deformation mechanism was shear along the weak planes that is located close to the parallel bedding, see figures 2.3.4.4.
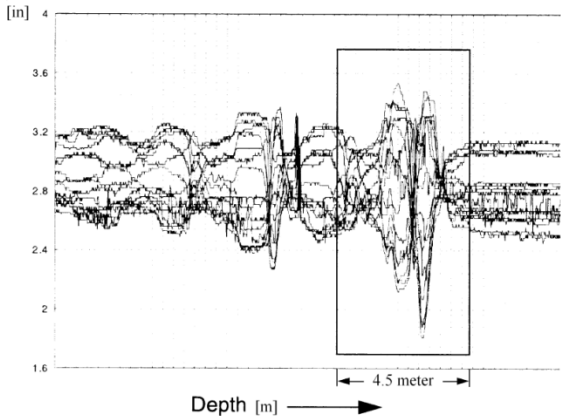
Figure 2.3.4.3: Show an example of a calliper run through a casing deformation in the overburden of Valhall. This example is from a pipe with an ID of 3,002 in. The outlined interval is a 4.5 meters interval. [Kristiansen et al., 2000]
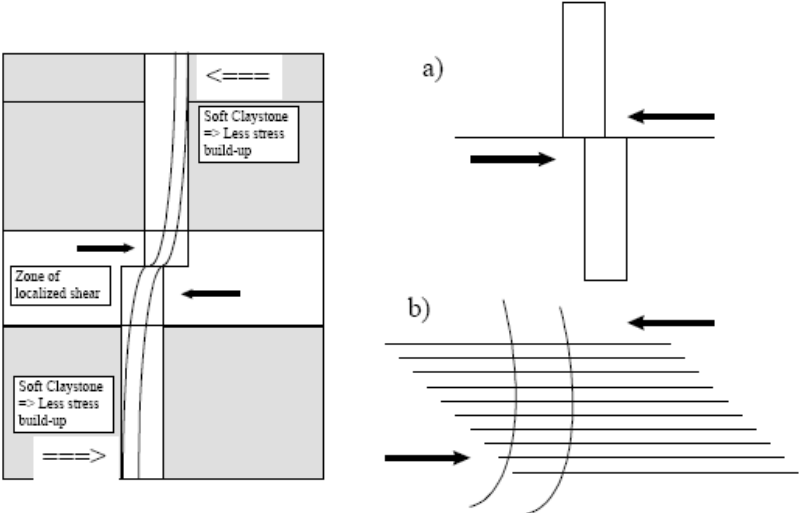
Figure 2.3.4.4: Show an illustration of localized shear as observed on Valhall and Ekofisk. A very much localized shear (a) will result in rapid casing deformation, compared to more distributed shear load over a larger area (b) which will slow down the pipe deformation. [Kristiansen et al., 2000]

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2.3.5 Special Requirements on Valhall

A program that tests a large amount of deformation of pipes and cement and numerical simulation, has resulted in a prioritized list of migration strategies, as presented in [Kristiansen et al., 2000]:

1) Increased wellbore diameter with no cement between wellbore wall and outer pipe.
2) Increased steel grade of inner pipe in a concentric configuration with cement between the two pipes.
3) Increased steel grade of outer pipe in a concentric configuration with cement between the two pipes.
4) Decreased D/t ratio of inner pipe in a concentric configuration with cement between the two pipes.
5) Decreased D/t ratio of outer pipe in a concentric configuration with cement between the two pipes.
6) Using sealed casing connections.
7) Minimize pressure differential between pore pressure and internal pressure in the inner pipe.

Following migrations techniques have been implemented or are under evaluation at Valhall:

- By using a near bit reamer, the traditional $12^{1}/_{4}$" wellbore size has been enlarged to approximately 14". Larger holes has been evaluated, but because of potential wellbore stability problems, separate under-reaming operations, and hole cleaning problems result in a larger risk than the benefit.

- There is no cement behind the casing in the overburden except the cement interval due to the requirements from NORSOK, which is 200 meters above the casing seat at the top of the reservoir. So far there has been a major challenge to get a good cement job at this formation, which is the Lista formation. At this time, the annulus above this cement interval is filled with oil based mud, and there has been identified some special gels and temperature dependent gelling additive for use in this annulus. These gels will prevent shale cavings from falling between the wellbore and the casing, and then create a bridge that could transfer load from the formation to the casing.

- Production liners with low D/t-ratio have been set as far up as possible into the overburden. This tactic is compromised by the risk of a poor cement job in the reservoir. A bad cement job in this section will have a negative impact both on well life and stimulation quality. Tie-back strings have been used on top of the liner lap in some cases. These tiebacks have been extended up into the overburden in cases where faults are crossing the wellbore. Typically low D/t-ratio liners are $6^{5}/_{8}$" 66 lbs/ft or $5^{1}/_{2}$" 44 lbs/ft, and there is cement between the production casing and the liner.

- There has been decreased D/t-ratio and the tubular weight of the production casing, and steel grade Q-125 has been used.

2.4 General Industry Casing Design

Casing design is an important part of a well drilled for production of oil and gas, or water injection. Different types of well have different requirements, but they all need to follow the government regulations according to NORSOK D-010, rev.3, and local considerations have to be made for each well.

The casing design involves the evaluation of different loads that will impact the string, such as collapse, burst, tensional and triaxial loads, among other factors.

2.4.1 BP's Policy Statements for Casing Design

BP has its own Policy Statements for casing design that have to be followed, [BP Casing Design Manual, 1999]:

1) For all wells, a casing design shall be performed, and there is a requirement that the casing design has to be checked and approved by a competent person other than the designer.

2) Fracture and pore pressures must be checked associated with all available offset data to ensure reliability with predicted values. The pore pressures and the kick tolerance at each casing shoe are recommended to be monitored continuously while drilling. This is to make sure that assumptions made at the casing design stage are not violated.

3) Casing setting depths must be selected in a way to provide a sufficient safety margin between formation fracture pressure and well control or casing cementing operations.

4) For all surface and intermediate casings/liners, kick tolerances must be calculated. Where drilling will take place through the production string, kick tolerances shall be calculated for that string as well.

5) All surface and intermediate casings and liners should be designed to meet well control burst loadings, with less risk of casing failure than of exposed formation failure.

6) In case of a tubing leak, production casing/liners must be designed for burst to withstand the highest shut-in tubing pressure at the surface on the casing to tubing annular fluids.

7) Minimum design factors applicable to material with yield stress of 125,000 psi or below for all casings shall be in accordance with table 2.4.1.1.

Table 2.4.1.1: BP's minimum casing design factors. [BP Casing Design Manual, 1999]

Design Criteria	Design Factor
Tension	1,4
Burst	1,0
Collapse	1,0
Triaxial	1,25

8)   Where the diameter to wall thickness (D/t-ratio) is less than 15, triaxial design factors shall be calculated where outside, internal pressure is greater than 12,000 psi, or H_2S service. Triaxial design factors must be calculated for casings under combined burst/compression loadings, and it is recommended that triaxial design factors are calculated for all casing.

9)   When production casing and tubing may be exposed to continuous H_2S/CO_2 environments, only seamless grades of tubular are acceptable.

10)   For exploration and appraisal wells, the maximum anticipated wellhead pressure must take into account a gas column to surface, while for development wells, reservoir fluid shall be used.

11)   After drilling below the surface and intermediate casing/liners, it is recommended to perform a leak-off test (LOT) or competency test (except in carbonates). The results must be evaluated for their impact on the well plan, like kick tolerance and corrective measures implemented if necessary.

2.4.2 General Casing Design

A casing design consists of several different sizes of casings and liners, and there are several ways to combine these different casings and liners in a well. Figure 2.4.2.1 presents a design including most of the different types of casings and liners. The difference between a casing and a liner is that the liner does not go all the way to the surface but is suspended in the previous casing. The largest size of the casings is the conductor, and is typically 30" or 26" and goes maybe 100 meters into the seabed. The conductor is isolating the unconsolidated layers underneath the seabed, and supports the surface casing and the wellhead. The conductors' inner diameter should have a sufficient space for the surface casing with efficient clearance for cement displacement in between, and the outer diameter must allow for installation through the rotary table.

The surface casing is typically 20" or $18^5/_8$" and is placed a couple hundred meters into the formation below the seabed. The surface casings' main task is to isolate weak formation and provide minimum pressure integrity to be able to attach a diverter or a BOP to the top of the casing. The surface casing provides structural strength to the well so that the rest of the casing strings may be hung from top or inside of the surface casing.

The intermediate casing has a typical size of $13^3/_8$" or $13^5/_8$", and is placed between 1,000 and 2,000 meters below the seabed. This casing isolates the formations that are weak, may contain cavings or have abnormally pressured zones, and give sufficient well integrity for further drilling. More than one intermediate casing may be used due to abnormally pressurized and weak zones with lack of well stability.
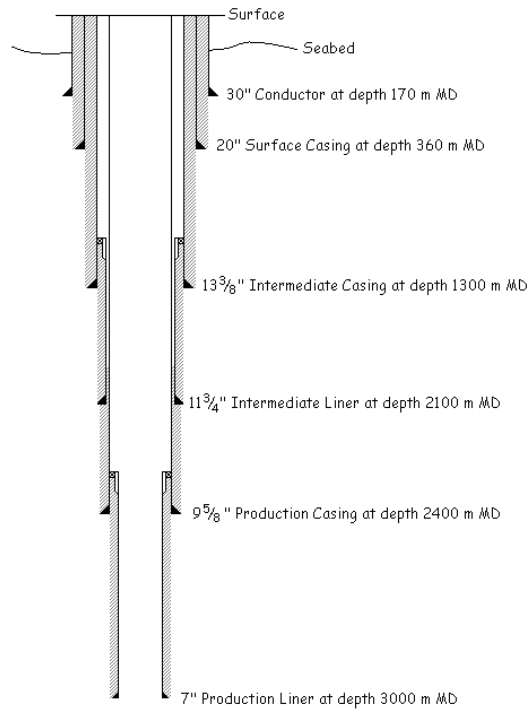
Figure 2.4.2.1: A casing design which include different types of casings and liners.

Intermediate contingency liner may be set between two casings if there is necessary to an extra isolation in the wellbore. This liner may have a size of $11^3/_4$" and fits between the $13^3/_8$" intermediate casing and the $9^5/_8$" casing.

The production casing has often a size of $9^5/_8$" and is set at the productive zones to isolate them. This casing must withstand chemical and mechanical wear that may occur from the formation- and completion fluids during the lifetime of the well. Another task of the production casing is to get a proper cement bond between the casing and the formation to prevent any annular migration of fluid along the wellbore, and maintain well integrity during the lifetime of the well.

The production liner has often a size of $7^5/_8$", $6^5/_8$"" or $5^1/_2$". This liner is mostly used when the production casing is only set at the top of the reservoir, but has the same requirements as the production casing.

Sometimes a tieback casing is used to increase the pressure integrity of the well in situations like flow testing, or to increase the resistance for H_2S/CO_2 corrosion when presented. There are different types of tieback strings. An intermediate tieback is used to isolate a casing string which cannot withstand possible pressure loads if drilling is continued. A production tieback isolates an intermediate string from the production loads. A tieback could be un-cemented or partially cemented.

For all casings and liners, BP uses a software program called CasingSeat made by Landmark to decide in which depths the casings and liners can be set.

When designing a casing program for a well, there are many categories that must be considered, like hole stability, formation pressure and well bore integrity, drilling fluids, hole cleaning and cementing precautions, hole curvature, mechanical equipment and economics.

In the book "Modern Well Design" [AAdnøy, 1996], the author AAdnøy has presented a list of these main categories and their different factors:

1) Hole stability:
   - Unconsolidated formations
   - Swelling clays
   - Fractured formations
   - Collapse and washouts
   - Zones with fluid losses
   - Plastic formations
   - Zone isolation
   - Creeping salts
   - Subsidence

2) Formation pressure and integrity:
   - High and low integrity formations
   - High pressure formations
   - Charged formations
   - Highly permeable formations
   - Well control integrity and margins

3) Drilling fluids, hole cleaning and cementing precautions:
   - Pressure losses, circulation densities and pump performance
   - Hole cleaning capabilities
   - Cementing of permeable intervals
   - H_2S and CO_2 containing intervals
   - Formation temperature
   - Mud system chemical and physical tolerances
   - Differential sticking
   - Reservoir invasion and damage

4) Hole curvature:
   - Kick-off points
   - Drop-off points
   - Hole angles
   - Dog-leg severity
   - Build-up and drop-off rates
   - Overburden stress regime
   - Potential side tracks

5) Mechanical equipments:
- Drilling rig hoisting and rotating capability
- Drill string and bottom-hole assembly capability
- Casing tensile strength, burst and collapse capability
- Mechanical wear on previous string
- Equipment availability

6) Economic:
- Equipment cost
- Perforation rate
- Pilot holes
- Time versus depth profile
- Probability and consequences of hole problems
- Primary and secondary objectives
- Formation evaluation and geological markers

When performing the well design, the risk evaluation is very important, and especially the evaluation of casing setting depths is fundamental to get a good design for well integrity.

The setting depth of the different types of casing and liner is mainly selected from the mud weight considerations, and these vary with geological formations, pressure regimes and experiences. After setting each casing, a leak off test is very important to perform to determine the weakest point of the wellbore construction.

A leak off test (LOT) is a pressure test performed after each set of casing. The LOT determines the pressure needed to force the fluid into the formation by forming a fracture, and is a method to find the formation breakdown strength of the rock. The result form the LOT indicates the maximum equivalent mud weight (EMW) that can be used in the next hole section without breaking the strength of the casing shoe.

The objective of casing seat selection is to achieve the total depth of the well safely with the most cost effective number of casings and liners. The requirements regarding casing seat selection, is that the production casing should always have full well integrity that is capable of handling kick.

General, the initial selection of casing setting depths is based on the expected fracture- and pore pressure gradients, showed in figure 2.4.2.2a. A casing is set to be able to increase the mud weight when drilling further towards higher pressurized formation. The mud weight must always stay above the pore pressure gradient to prevent influx from the formation, and below the fracture gradient to prevent fracturing the formation. The minimum casing setting depth is given by the effective mud gradient and the fracture gradient, showed in figure 2.4.2.2b. To prevent fracturing, the casing has to be set at least at the depth where the fracture gradient is larger than the effective mud gradient.
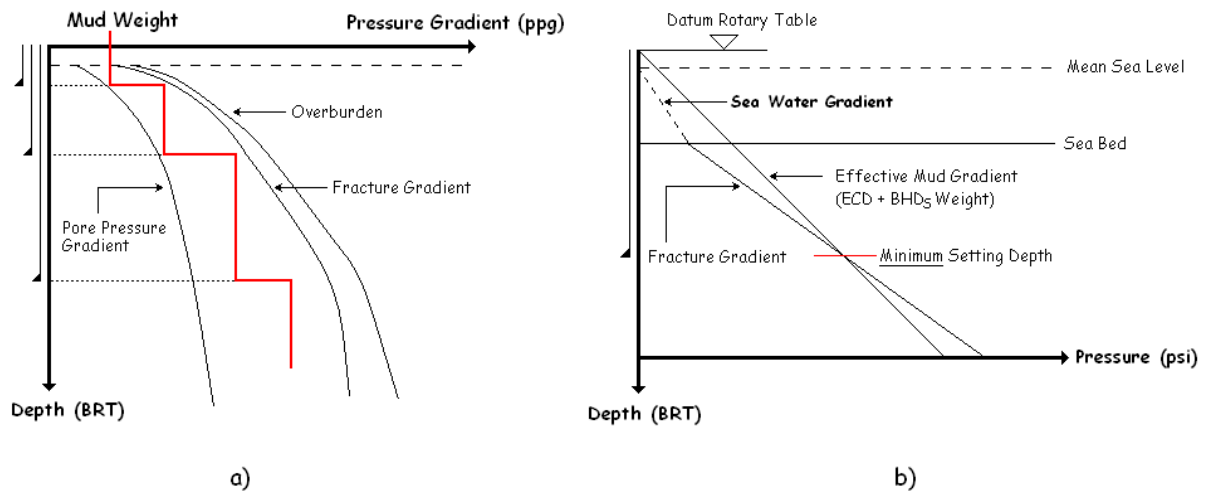
Figure 2.4.2.2: a) Pore pressure and a fracture pressure gradient, and how to select the setting depth of the casing according to these gradients. b) Show how to find the minimum casing setting depth from the effective mud gradient and the fracture gradient. Modified from [BP Casing Design Manual, 1999]

Most often, equivalent circulation density (ECD) has a minimal impact on the effective mud weight at the casing shoe. However, in areas where lost circulation is critical, the ECD should be included in the calculations.

Equivalent circulating density is the effective density exerted on the formation that takes into account the pressure drop in the annulus that is above the considered point. The ECD is given by equation:

$$ECD = d[ppg] + \frac{P[psi]}{0,052D[ft]}$$ (2-9)

where *d* is the mud weight, *D* is the true vertical depth (TVD) and *P* is the pressure drop in annulus between depth D and surface. ECD is an important parameter to avoid losses and kick, especially in wells that have a small clearance between the pore pressure gradient and the fracture gradient.

As far as possible, the drilling engineer should ensure that the offset data have been considered when estimating these gradients, and that the effect of the estimation of the hole angle on offset fracture gradient data have been considered as well. Once the initial casing setting depths is selected, kick tolerances are determined according to these depths from total depth and up to the surface.

Kick tolerance is the maximum difference between the mud weight that is in use and the pore pressure that can be encounter to control the kick without fracturing the weakest vulnerable formation. The kick tolerance is usually expressed in units of volume, and is calculated when assuming natural gas as the kick fluid. The maximum pit gain that would be expected before the BOP is closing must be assumed as well. An estimate of the volume of a kick at bottom-hole conditions which can be shut in and circulated out is given by following equations:

$$P_{max} = P_{leakoff} - Safety\ Margin$$ (2-10)

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and:

$$H = \frac{P_{\max} - P_f + (TD - D_{wp})(MW)(0,052)}{0,052MW - gg}$$

(2-11)

where *H* is the height of gas column below weak point, P_f (psi) is the expected formation pressure, *gg* (psi/ft) is the gas gradient, *MW* (ppg) is the mud weight in the hole, D_{wp} is the weak point depth. From this it is possible to calculate the total volume of influx above the bit given by:

V_1 = H x Annular Capacity above bit (initial influx volume)

(2-12)

and the total volume of expanded influx below the weak point given by:

$$V_2 = P_{\max} \frac{V_{wp}}{P_f}$$

(2-13)

where:

V_{wp} = H x Annular Capacity below weak point (expanded influx volume)

(2-14)

and then the kick tolerance is the smallest value of V_1 and V_2.

In a casing design process, there is a lot of data needed, and some of them that are presented in BP's Casing Design Manual [BP Casing Design Manual, 1999], are:

- Well locations, water depth, total depth, objective depth.
- The planned trajectory.
- Is it an Exploration well or a Development well.
- The limitations of the rig, like hook load, which may affect the choice of weight and steel grade of the casing strings.
- Evaluation requirements like logging, coring or testing, which will impact the mud types and the hole-size.
- Required testing- and production rates, which will impact the size of the production- casing and tubing.
- Hydrocarbon composition, like oil or gas. Corrosion expected from H_2S, CO_2, or Cl that will impact the selection of material, cost and lead time for pipes.
- Producing life of the well, completion design and intervention procedures like ESP's, gas lift, N_2 kick off, fracturing, annular cutting injection and associated temperature predictions.
- Geological information's like formation tops, faults and structure maps.
- Geostatic temperature profile, pore pressure- and fracture gradients.
- Offset well data, which is a well drilled in the same area. These data may be casing programs, geological tie-in, mud weights and operational problems.
- Hazards and constraints, like shallow gas, lease line, restrictions and faults.
- Completion component down-hole and tubing sizes.
- Annulus communication, bleed off and monitoring policies.

Every casing and liner strings, included the connections shall be designed to withstand all different loads and pressure include their safety factors that can be expected during the well's life time. To verify that the casing or the liner could handle these loads, they should be tested to maximum differential pressure that could be anticipated in the well.

There is a lot of different loads that will expose casing strings, both while installation, drilling and production. Installation loads may be during running the casing and cementing operations. Drilling loads may be pressure testing of the casing after WOC, lost circulation, gas influx loads, maximum mud weight and temperature rise for the next section. Production loads may be pressure testing with completion fluid or mud as required, DST pressure testing with mud or kill weight fluids, near surface tubing leak during production, collapse loading below production packers, and special production operations, like injection, gas lift stimulations and ESP's.

Some major factors that will affect the casing setting depth selection, is shallow gas zones, lost circulation zones, sidetrack requirements, uncertainty in depth and pressure estimation, ECD at casing shoe, and formation stability sensitive to mud weight, both static and ECD.

The casings that are going to be used in the well, have to be designed to different criteria like collapse, burst, tension and triaxial loading. These different designs are being calculated in the software program StressCheck that is made by Landmark. This program calculates every critical operation and limiting design loads for the different designs in every section.

2.4.2.1 Collapse Design

Design issues for a collapse design, is when the external pressure is higher than the internal pressure, and the pipe could fail and the pipe changes shape from circular to a non-circular shape due to a combination of yielding and elastic instability. It is very important to avoid this because when pipes collapse in the well, equipment may not go through the inner diameter of the pipe, and very often it leads to sidetrack or even abandonment of the well. Due to axial compression, the collapse resistance of the pipe will increase, and with axial tension, the collapse resistance will decrease.

A typical situation of collapse failure is mud losses to thief zones, which could occur during drilling when large amount of mud disappear into the formation. While drilling a new section and start losing mud to thief zone, the fluid level in the inner annulus will drop until the hydrostatic pressure of the fluid column is in equilibrium with the pore pressure at the thief zone. Outside the casing, outer annulus, there is a certain pressure, and because of the drop in the inner annulus, collapse pressure may occur.

Another situation that may lead to collapse of the casing is during cementing. Instantly after setting the cement, the cement is wet and mobile and will along with the seawater provide a large hydrostatic pressure at the bottom of the casing. This is often in cases where the casing is cemented all the way to the surface, as the surface- and intermediate casings.

2.4.2.2 Burst Design

When the internal pressure exceeds the external pressure on the casing, the casing may burst. Burst loads are very often associated with influx of fluid with a lower density into the wellbore. When a pipe burst, there is a material failure and the pipe loses its integrity. Most common situation where the casing may burst is when gas fills the whole well, and then the pressure at the wellhead is the formation pressure minus the weight of the gas column, while the pressure in annulus is only hydrostatic which is a much lower pressure.

In a situation where the well is being tested, or during production, the tubing may get a leak near the wellhead, and then there is a large chance that the casing will burst at top of the production packer. This is because of the extra wellhead pressure that will be added at top of the production packer along with the weight of the completion fluid, while outside the casing there is a constant hydrostatic pressure made by mud or water. The differential pressure above the production packer may be large enough to burst the casing.

2.4.2.3 Tension Design

When the axial load exceeds the yield strength of the pipe, it is called a tension failure and the pipe will be parted. There are many situations where the pipe may get a tensional failure, and some of them are:

- Shock loads
- Axial load
- Weight of casing in air
- Buoyancy load effect, both with closed- and open ends
- Bending
- Surface pressure to bump cement plug
- Over-pull to land and pull casing
- Tensile loads due to change in pressure from mud weight
- Tensile load due to fluid friction
- Different installation loads like running and cementing casing

2.4.2.4 Triaxial Design

A triaxial design is required to ensure no localized strain concentrations or excessive displacement which may invalidate burst check or cause failure on load reversal. The main reason to perform a triaxial design is to avoid local yielding, especially during buckling above top of cement or if strings are landed on bottom. Axial loads with internal and external pressures generate triaxial load on a pipe, often known as the principle stresses. These stresses are the tangential stress, σ_t, radial stress, σ_r, and axial stress, σ_a, as showed in figure 2.4.2.4.1.
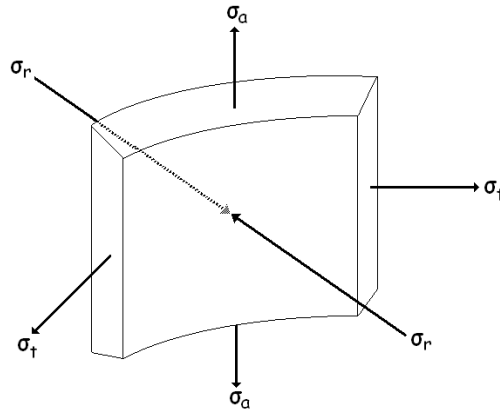
When calculating the triaxial stresses, von Mises theory is the recommended method. The von Mises theory is defining an equivalent stress (σ_{VME}) to relate the different stresses to a minimum yield stress, σ_Y, of the casing. The von Mises equivalent stress is given by equation:

$$\sigma_{VME} = \sqrt{\frac{1}{2}\left[(\sigma_a - \sigma_t)^2 + (\sigma_t - \sigma_r)^2 + (\sigma_r - \sigma_a)^2\right]}$$
(2-15)

where σ_t is the tangential stress, σ_r is the radial stress, and σ_a is the axial stress as mentioned before. According to the von Mises theory, an axial tensile stress may increase the tangential stress capacity before first yield of the casing, and vice versa. This phenomenon is illustrated in figure 2.4.2.4.2, which is a diagram that show that the location of the different lines depend on the design factors and allowable wear.
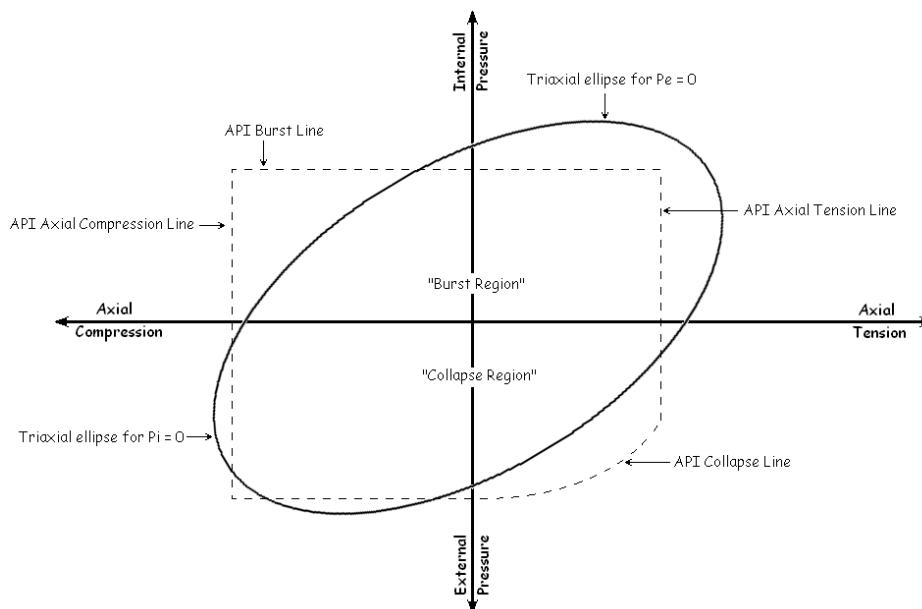
Figure 2.4.2.4.2: Show a Triaxial Load Capacity Diagram. Modified from [BP Casing Design Manual, 1999]

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The different principle stresses is given by the following equations:

Radial stress:

$$\sigma_r = \frac{P_i r_i^2 - P_e r_e^2}{\left(r_e^2 - r_i^2\right)} - \frac{\left(P_i - P_e\right)r_i^2 r_e^2}{\left(r_e^2 - r_i^2\right)r^2} \qquad (2\text{-}16)$$

Tangential stress:

$$\sigma_t = \frac{P_i r_i^2 - P_e r_e^2}{\left(r_e^2 - r_i^2\right)} + \frac{\left(P_i - P_e\right)r_i^2 r_e^2}{\left(r_e^2 - r_i^2\right)r^2} \qquad (2\text{-}17)$$

Axial stress:

$$\sigma_a = \frac{F_a}{A_s} \pm \sigma_{hb} + \sigma_{dev} \qquad (2\text{-}18)$$

where P_i is the internal pressure, P_e is the external pressure, r_i is the internal radius, r_e is the external radius, r is the radius where stress is calculated, F_a is the total axial load excluding the bending components, A_s is the area of the steel, σ_{hb} is the helical buckling stress, and σ_{dev} is the bending stress due to wellbore dogleg severity. Both σ_{hb} and σ_{dev} are local axial stresses that vary along the casing.

2.4.2.5 Casing Wear

Casing wear is physical assault on the steel material that most often occur during drilling kick-off sections or in general high dog-leg severities, like illustrated in figure 2.5.2.6.1. Wear on the casing have several negative effects before a failure of the material occur. Some of these effects are that the wear groove reduces the pressure integrity of the well which will affect the leak-off, testing and production procedures. Another effect is the extra torque and rotational friction. When the casing is exposed to enough wear, the strength of casing material is reduced, and a burst or a collapse failure is possible.
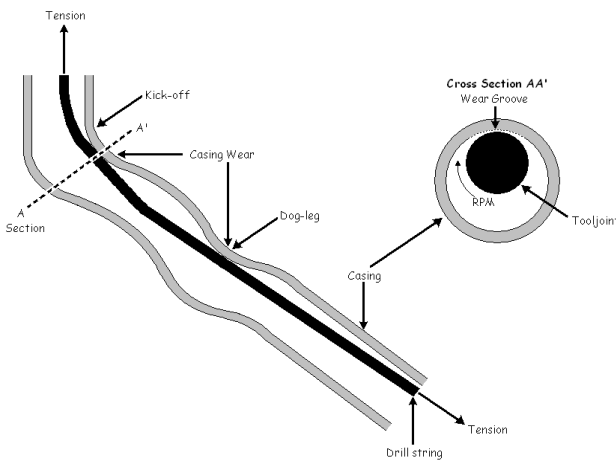
Figure 2.4.2.5.1: Illustrate how the wear is occurring on the casing during drilling in high dog-leg severities. Modified from [BP Casing Design Manual, 1999]

There are three different main types of wear that could occur, is adhesive wear, machining abrasive wear, and grinding/polishing abrasive wear.

Adhesive wear is known as galling as well, and it is when a tool joint looses wear particles which can be like flake-like wear debris, as showed in figure 2.4.2.5.2.
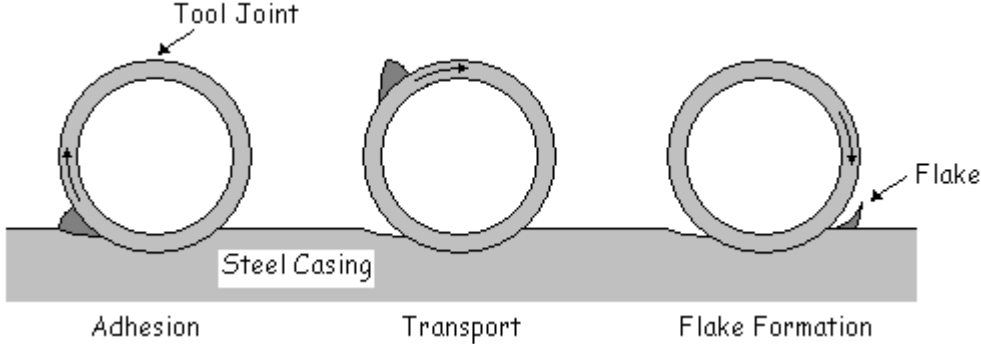
Figure 2.4.2.5.2: Show an example of adhesive wear. Modified from [BP Casing Design Manual, 1999]

Machining abrasive wear is when there is larger removal of the affected surface, like when the drillbit with tungsten carbide is cutting into the casing as illustrated in figure 2.4.2.5.3.
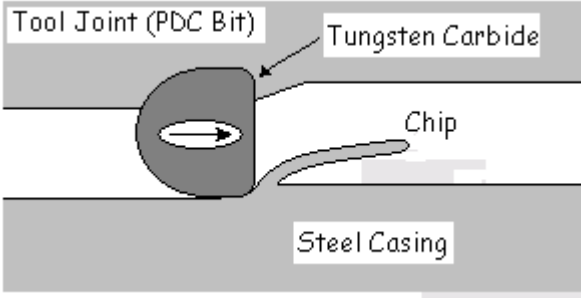
Figure 2.4.2.5.3: Show an example of machining abrasive wear. Modified from [BP Casing Design Manual, 1999]

Grinding/polishing abrasive wear is when hard particles become trapped between the tool-joint and the casing surface and abrade one of them or both, as showed in figure 2.4.2.5.4.
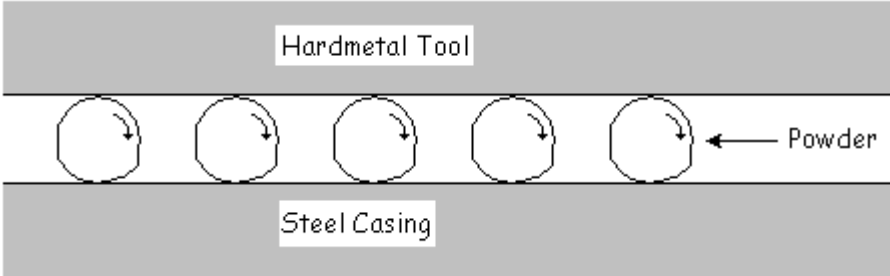
Figure 2.4.2.5.4: Show an example of grinding/polishing abrasive wear. Modified from [BP Casing Design Manual, 1999]

To prevent major casing wear, BP uses a software program called CWear made by Landmark to predict the casing wear that it might be exposed to.

2.4.2.6 Buckling and Compression

In addition to the mentioned design criteria, buckling and compression has to be considered as well. Buckling of tubing or casing is a form of elastic instability that most of the times happens in unsupported intervals of the casing, like where no cement is located. Buckling is large sideways displacements and failure. The displacement of a casing or tubing is limited by the wellbore or the previous casing. This means that the total radial deflection is equal to this clearance, often referred as to sinusoidal buckling. If the compressive loads are large enough, the pipe buckled string shape will be a helix, as showed in figure 2.4.2.6.1 along with sinusoidal buckling.

a)   b)
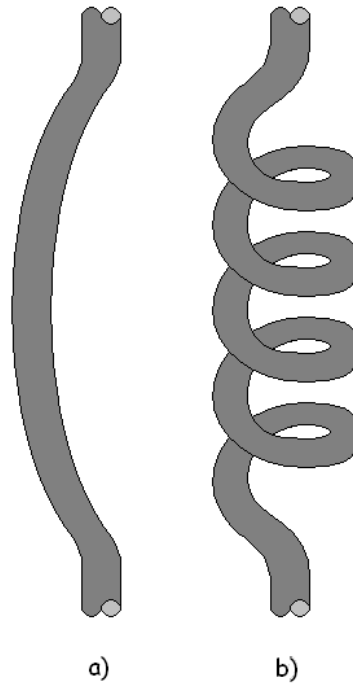
Figure 2.4.2.6.1: a) show a sinusoidal buckling situation, while b) show a helical buckling situation.

When the effective tension that affect the pipe is positive, buckling will not occur, but if the effective tension is negative, there may be resulted in buckling. The equation for effective tension, F_{eff}, is given by using the Lubinski buoyancy formulation, [Lubinski et al., 1962]:

$$F_{eff} = F_t + \left(P_e A_o - P_i A_i \right)$$
(2-19)

where F_t is the axial force at the point of interest, P_e is the external pressure at point of interest, P_i is the internal pressure at point of interest, A_o is the outside area of the tube cross-section, and the A_i is the inside area of the tube cross-section.

In a vertical well, the critical buckling force is given by Euler's equation:

$$F_c = -k\pi^2 \frac{EI}{L^2}$$
(2-20)

where L is the length, E is the Young's modulus for steel, and I is the pipe cross-sectional moment of inertia, and k is a parameter that varies with the conditions at either end of the pipe. The largest

value of k corresponds to both ends of the pipe being fixed such that neither lateral displacement nor rotation is permitted, is k=4, [BP Casing Design Manual, 1999].

Cross-sectional moment of inertia is given by:

$$I = \frac{\pi}{64}\left(OD^4 - ID^4\right)$$
(2-21)

Critical buckling force that may lead to buckling in inclined wells, however, is given by equation derived from Dawson and Paslay [Dawson and Paslay, 1984]:

$$F_c = -\sqrt{\left[\frac{4EIw_e \sin\alpha}{r_c}\right]}$$
(2-22)

where E and I is the same as mentioned before, w_e is the effective weight per unit length, r_c is the radial clearance between the hole and the outer diameter of casing, and α is the inclination angle compared to vertical direction. In inclined wells, buckling will occur if the critical buckling force is higher than the effective tension, which means that the effective tension must be more negative than the critical buckling force which is negative as well.

2.4.2.7 Uniform Loading

Uniform loading is when the effective overburden pressure is transmitted to the considerable length of the casing string in a uniform manner. This type of loading can be modelled in casing designs by substituting the overburden pressure at any depth for the hydrostatic pressure. The API rating for any single casing string may be used to select the appropriate casing required.

When there is competent cement sheath between two casings, the combined collapse rating is the summed collapse value of the two casings, and is independent of the degree of eccentricity of the two strings.

2.4.2.8 Non-Uniform Loading

Non-uniform loading is when the effective overburden pressure is transmitted to a limited area of the casing string. When the casing is being exposed of non-uniform loading, the string may fail at a value between 20 and 30% of its API rating. Even if there is a good cemented concentric casing string, that will have a larger collapse resistance, will unlikely stand the strain from a non-uniform loading.

To double the non-uniform load resistance it is necessary to double the yield strength of the pipe, while increasing the wall thickness of the pipe with 40% will achieve the same effect, [Pattillo et al., 1995].

The most regular function of a concentric casing is to withstand the ovalization of a cross sectional that is affected by non-uniform loading. The collapse rating that API defines is based on that the external pressure is affecting the whole tube, but the arising stresses from a flowing formation are

not necessary directed radially, which mean that the API ratings are not applicable. Nester (1956) considered non-uniform cross-sectional loading in two different distributions as showed in figure 2.4.2.8.1. He used yield as failure criterion and discovered that for the non-uniform loading, the distributed load Q causing yielding is given by:

$$Q \cong \frac{3\sigma_Y}{\left(\dfrac{D}{t}\right)^2}$$

(2-23)

where σ_Y is the yield stress, t is the wall thickness and D is the outside diameter.

a) Uni-directional Load   b) Opposed Line Loads
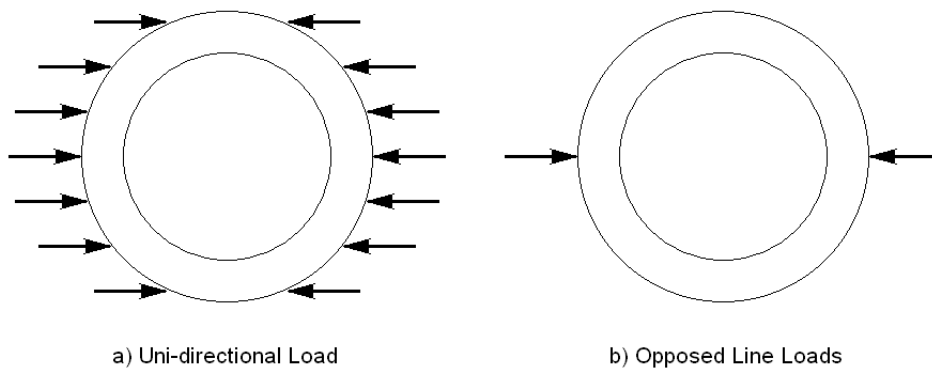
Figure 2.4.2.8.1: Non-uniform loads considered by Nester, et al. Modified from [Pattillo et al., 1995]

In the other case which is opposite line loads, the intensity R that causing yielding is given by:

$$R \cong \frac{\sigma_Y}{\left(\dfrac{D}{t}-1\right)\left(0{,}96\dfrac{D}{t}-0{,}32\right)}$$

(2-24)

and the parameters σ_Y, D and t is as mentioned above.

Figure 2.4.2.8.2 illustrate when a casing in a horizontal section is exposed to line-load, where a) is after the casing is set, b) is after a certain time with chalk production, and c) where the casing has collapsed during compaction of the reservoir.

a)   b)   c)
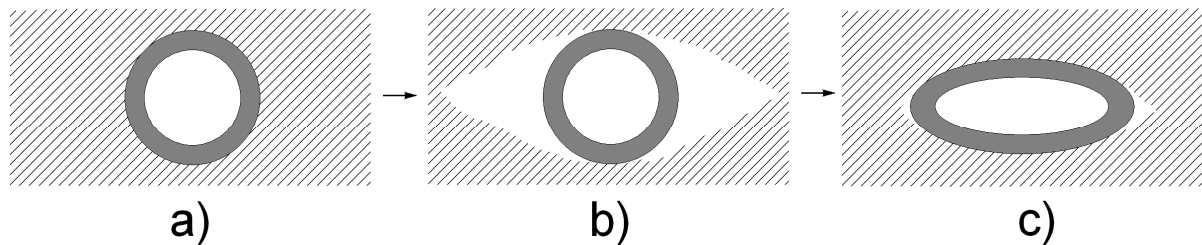
Figure 2.4.2.8.2: Illustrate the result from a casing being exposed to line-load at a horizontal section.

2.4.3 Contingency

For every planned well, there will be contingency casing strings available and engineered. A contingency is a backup plan of the casing design if it is not possible to set a casing section at the planned setting depth. A situation like this could be if there is not possible to drill the reservoir section as one section. Figure 2.4.3.1 show an example of the difference between an original casing design and a contingency plan.
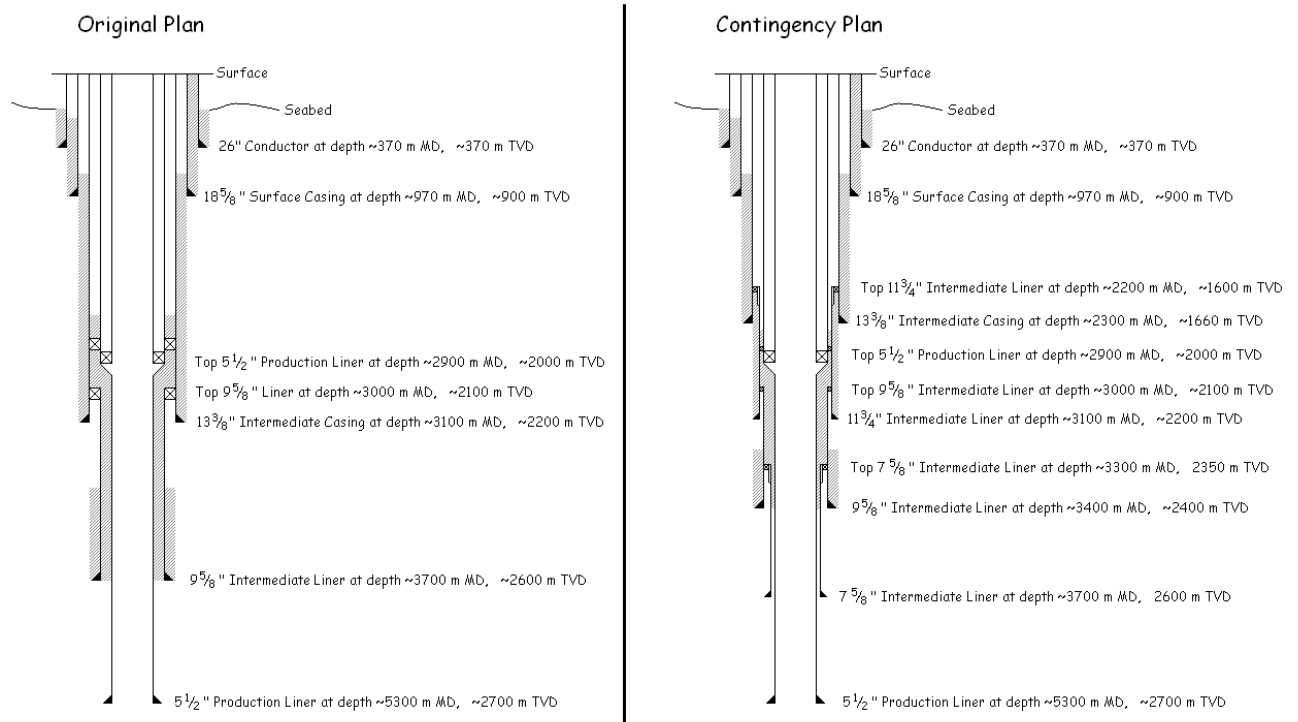
Figure 2.4.3.1: Show an example of the difference between an original casing design and a contingency plan.

In this example, the $13^3/_8$" intermediate casing was not able to be set at ~3,000 m MD, but only ~2,300 m MD. An additional $11^3/_4$" intermediate liner is then set approximately 100 m MD above the casing shoe of the $13^3/_8$" casing, and down to this casing's original shoe depth at ~3,100 m MD. It was not possible to set the $9^5/_8$" intermediate liner on its original shoe depth as well, but at approximately ~3,400 m MD. A $7^5/_8$" intermediate liner is then set at approximately 100 m MD above the casing shoe of the $9^5/_8$" casing, and down to ~3,700 m MD instead of the $9^5/_8$" casing. The production liner is set as original planned, at ~5,300 m MD.

A contingency plan may vary in different wells, and it is not always necessary to use the whole plan. Sometimes it is only requirement to use the $11^3/_4$" contingency liner and not the $7^5/_8$" liner, and vice versa. It is only depending on how good the original plan is working.

The disadvantage with a contingency, except for the additional casing sizes, is the reduction of ID in the well. For example, if the $11^3/_4$" liner is needed, then the next section could not be drilled as an ordinary $12^1/_4$" section as planned, but it has to be under-reamed from $10^5/_8$" to $12^1/_2$", because a $12^1/_4$" bit does not fit through the $11^3/_4$" liner. This under-reaming process is expensive and difficult.

2.4.4 Barrier Philosophy on the Norwegian Continental Shelf

All drilling and intervention operations on the NCS are governed by the Petroleum Safety Authority of Norway (PSA). The PSA is the regulatory authority for technical and operational safety, including the working environment and emergency preparedness. The PSA have developed and defined regulations for technical and operational safety, [PSA, 2009].

The PSA guidelines often refer to recognized local Norwegian and international standards, such as ISO, IEC, API, NORSOK, DnV, and OLF as a way to fulfil the functional requirements in the regulations. International standard, ISO, form the basis of all activities in the petroleum industry. Experts from a wide range of companies participate in the development of ISO standard, in order to define safe and economical design and processes. However, Norwegian safety framework and climate conditions require amendments to the ISO standard. The NORSOK standards are developed to form these necessary amendments, and are developed by the Norwegian petroleum industry to ensure sufficient safety, value adding and cost effectiveness for existing and future petroleum industry developments in Norway.

The NORSOK standard that describes well integrity requirements during drilling and well operations is the NORSOK standard D-010. This document describes the requirements for well barriers at all stages of drilling and well operations. Some of these requirements are, [NORSOK, 2004]:

- It is required at all times that there are at least two independent well barriers between surface and the potential source of inflow if it is a reservoir. If the primary barrier fails, a second barrier exists to prevent well leakage.
- Each and every barrier element must be verifiable through some form of testing.
- If any barrier fails it must be repaired before other activities can be carried out.
- Permanent well barriers must be in place prior to well sidetracks, suspension and abandonment.
- There shall be at least 100 meter cement column above each casing shoe.
- If a cemented casing is not drilled out, there should be at least 200 meters cement column above potential inflow/leakage point, or to the previous casing shoe, whichever is less.
- Verification requirements of the minimum cement heights must be performed by logs, or verified by estimation on the basis of records from the cement operations, which could be volumes pumped and returned during cementing.

3 Potential Technology to be Included in Current Casing Design

There are several different technologies that can be included in the current casing design on Valhall that might have a positive impact on the barrier challenge, and the injection pressure. Of all the different technologies on the market today, only a few of them with high potential have been investigated in this thesis. These selected technologies have been collected from searching the SPE technical library, the internet, colleagues at BP and contacts with service providers.

3.1 Drilling Liner

Drilling liner has been used on Valhall since 1993, and is a very good method to decrease the large losses when drilling into depleted Tor formation. This technology has been included in this thesis since it is the recommended drilling method today when entering the reservoir. A drilling liner is a non-retrievable system that combines a special PDC bit in the end of the liner, as showed in figure 3.1.1. This special PDC bit makes it possible to drill through with a smaller bit when drilling the next section.
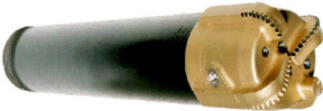
Figure 3.1.1: Show a PDC bit in the end of the liner. [Davies et al., 2006]

When using the liner in a drilling operation, every component of the liner must withstand the large torque and loads created during the drilling operations. The weakest element might be the running tool which is attached to the liner hanger at the top of the liner, as showed in figure 3.1.2.
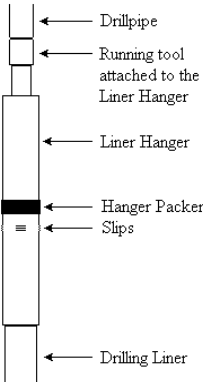
Figure 3.1.2: Show the principle of how the drilling liner is attached to the liner hanger, the running tool and the drillpipe.

The running tool is attached inside the liner hanger before it is sent down hole along with the drilling liner. Once the drilling liner has finished the drilling operation, or gets stuck in Valhall's case, a ball is dropped and lands in the ball seat at the bottom of the liner. The string is then pressured up to activate the slips which set at the liner hanger, and the running tool is released from the liner hanger.

When the running tool is pulled almost up from the liner hanger, some locking arms are ejected that is larger than the OD of the liner hanger. Then it is set a large amount of compressive weight on the running tool, which at a certain compressive load will compact and eject the hanger packer. When the hanger packer is activated, the running tool is pulled. This process is illustrated in figure 3.1.3.
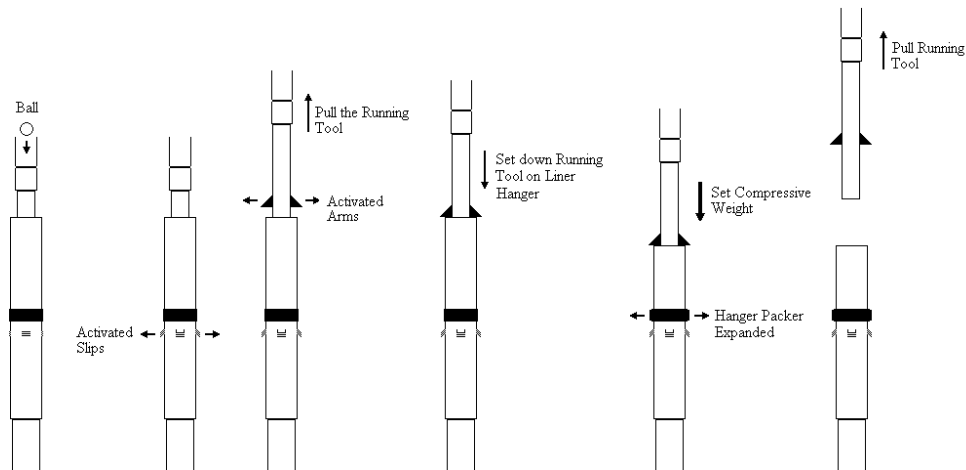
Figure 3.1.3: Illustrate the process of setting liner hanger and hanger packer.

If the hydraulic release mechanism between the running tool and the liner hanger is failing, the running tool incorporates a secondary mechanical release mechanism which activates by applying counter clockwise torque at the tool. This system is used both in drilling liner applications and conventional liners.

There are several risk factors by using a drilling liner, and some of them are as presented in [Davies et al., 2006]:

- Damage to liner bit
- Surface instability
- Losses
- Bit whirl
- Drilling with incorrect WOB
- Tight spots
- Axial vibrations
- Plugged nozzles
- Incorrect connection procedures
- Cementing operations
- Drill-out of PDC liner bit

Several evaluations are performed before drilling with a liner, and one of the most important is a "torque and drag" evaluation. This evaluation determines the forces that will act on the drilling liner during drilling, such as torque, buckling, tension and compression. It is important to know how much the drilling liner has to handle, at least, to be able to decide which one to use. Other limitation that has to be considered is the maximum delivering torque from the Top-Drive.

The drilling liner is perhaps the only alternative to be able to drill into low pressured formations as the Tor formation on Valhall.

3.2 C-Flex Port Collar from PEAK Well Solutions

C-Flex port collar has been used on current casing design on Valhall, due to cement squeeze jobs at top of the reservoir. This technology has been included in this thesis because it could still be one of the best solutions, perhaps in combination with other technologies. PEAK has tried to run the C-Flex with a foundation below, that has successful provided a better and more controlled cement job. This has not been tried on Valhall yet, but it would be worth investigating.

3.2.1 General Principle

Compared with a common Port Collar, C-Flex is a new generation stage tool due to its close and permanent locked feature. A C-Flex is a high-end sliding sleeve port collar that is an integral part of the casing or the liner to access the annulus after the casing or the liner has been installed and cemented. To ensure total control of all the fluids pumped into the well, especially cement, the sliding sleeve is operated with a cementing tool that is attached to the drillpipe. The C-Flex may be used as a circulation tool for liquids in the annulus as well as cementing. In order to prevent any collapse or burst of the C-Flex, the mechanical strength is at least the same as the casing or the liner the C-Flex is installed with. The C-Flex is shown in figure 3.2.1.1.

Figure 3.2.1.1: Picture of a C-Flex. [PEAK, 2009]

Another benefit with the C-Flex compared with a conventional port collar, is the better control of the sliding sleeves to prevent any prematurely or accidental opening by bottom hole assemblies or casing scrapers. To open the sliding sleeves in the C-Flex, a force larger than 12 tons must be added, and a force of 6 tons to close them. In addition, a version with permanent closure feature is available that will ensure that the sliding sleeves will never open after it is closed. The C-Flex has a unique seal system that is designed for high differential pressures. The principle to how the C-Flex is working is illustrated in figure 3.2.1.2.
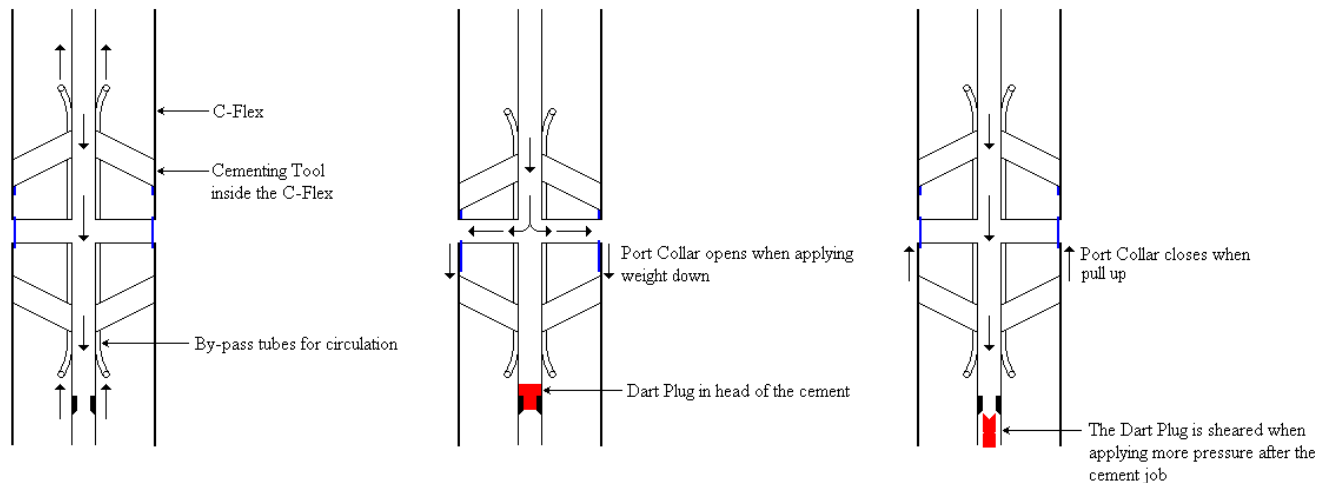
The C-Flex is a port collar tool used to create good cement bond behind the casing or the liner, and supply a zonal isolation in the reservoir and elsewhere in the well. It is possible to run several C-Flexes in the same casing or liner if there are uncertainties about fractures or faults in the formation. In this way, if one interval does not get a proper cement sheath, another interval might do, and make a proper annulus barrier and zone isolation. If using several C-Flexes, they all can be cemented in the same run, and save a lot of rig time and cost.

3.2.2 C-Flex in Combination with a Foundation

PEAK Well Solutions has tried out running a foundation along with the C-Flex that is installed right below. This foundation is made of aluminium and has a thin layer of rubber against the casing. The foundation has several one-way valves installed that make it possible to circulate. The foundation has a smaller outer diameter than the inner diameter of the wellbore to be able to rotate and install it. The principle of this foundation is to prevent the cement sagging below the port collar, as showed in figure 3.2.2.1. Even though the foundation does not seal all the way into the wellbore, the main part of the cement will be forced upwards.
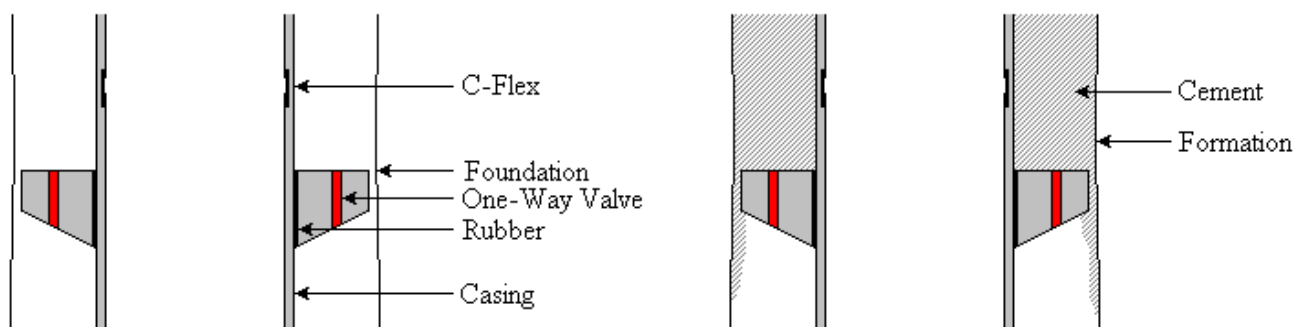
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3.2.3 Advantages and Disadvantages

Advantages and Disadvantages with C-Flex from PEAK Well Solutions are presented in table 3.2.3.1 below.

Table 3.2.3.1: Advantages and disadvantages of C-Flex from PEAK Well Solutions.

Advantages	Disadvantages
• Simplified operation • Cost effective • Time effective • Better control of the sliding sleeves • Multiple open and close • Can cement several different zones in the same run • Large ID and small OD reduce high ECD • Flexibility and control of cement volume and placement • Reduce the risk of loss zones • With use of the foundation, a much better and controlled squeeze job is performed	• Cannot confirm the quality of the cement job without logging • With use of the foundation, it cannot be included in a drilling liner, because large circulation as needed during drilling is not possible • With use of the foundation, the contingency is not available because of the larger outer diameter of the foundation

3.3 Expandable Liner

Expandable liner has not been used on Valhall, but is included in this thesis for investigating because it could be a potential technology that somehow can solve the barrier challenge on Valhall. By combining expandable liner with drilling liner is not even on the market today, but could have large potential in Valhall's case. Another technology called monodiameter drilling liner, where the concept is to maintain the same ID through the well would be investigated as a solution as well.

3.3.1 General Principle

Expandable liners is one of the technologies that have been applied to the oil and gas industry to increase income by allowing them to access reserves that cannot be reached with conventional technology. Overall, this technology saves cost and makes drilling more efficient.

Expandable tubular technology has proven to be a good solution when it comes to casing repair, as an alternative to straddle packers, squeeze cement or cementing a liner in place. Weakened, worn, corroded or eroded production casing may easily be replaced. The same technology is also used for isolation of zones with poor production or shutting off perforations. A casing patch or a liner is deployed into the well and expand at the predetermined depth. The expansion clads the two pipes together into one pipe, and replaces the casing with a minimal loss of inner diameter, as illustrated in figure 3.3.1.1.
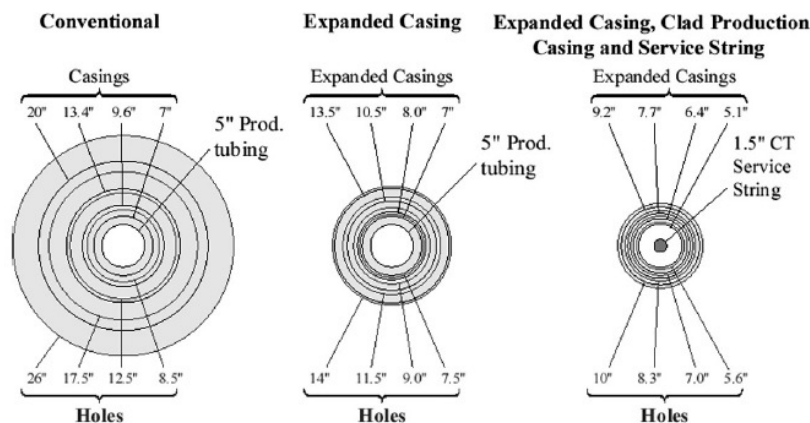
Figure 3.3.1.1: Conventional pipes compared to expandable pipes. [Stewart et al., 1999]

There are many service companies that deliver expandable liner technology, amongst others Baker Oil Tools, Weatherford and Enventure.

3.3.2 General Expanding Procedure

The first step in installing expandable liner is drilling and reaming the hole-section, preferable in one run. Reaming is needed to provide a larger diameter of the hole when liner is to be extended. A liner tube is typically expanded 15-20% of original outer diameter, [DeMong and Rivenbark, 2003]. The next step is to put the assembly together that consist of launcher and the required number of expandable casing lengths. Then the drillstring is run into the liner and connected to the expansion cone situated in the launcher while the assembly is hanging in the rotary table, and then run to the

predetermined depth. When the assembly reaches the bottom the cement job starts. It is possible to rotate and reciprocate the liner while pumping cement to ensure an optimal cement job. After the cement job is finished, a steel ball is dropped and reaches the launcher, sets and creates a pressure seal at the expansion cone. The expansion initiation is verified by a pressure response and a decrease in hook-load, and a hydraulic pressure starts building up behind the cone, as illustrated in figure 3.3.2.1. The liner is expanded in a speed at approximately 20 to 30 feet per minute. At the drillfloor, the pressure is bleed of, stand removed and the high pressure conduit is reattached until the liner is sealed to the previous casing. The cone is then retrieved to the surface and the shoe is drilled out. The sequence can be repeated when setting a new length of liner with the same inner diameter. This sequence is illustrated in figure 3.3.2.2.
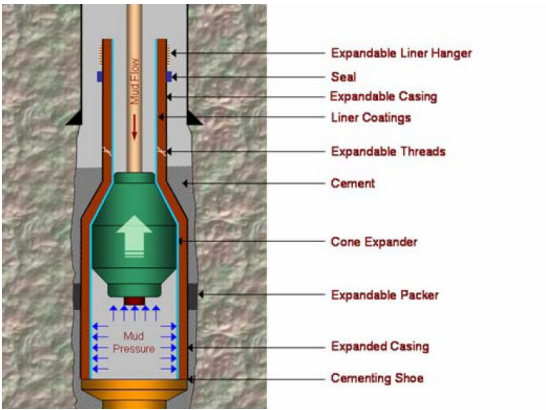
Figure 3.3.2.1: Expandable solid casing. [Ruan and Maure, 2005]

Figure 3.3.2.2: Principle of expandable liner. [DeMong and Rivenbark, 2003]

There are different methods of expansion, as illustrated in figure 3.3.2.3. Axial expansion is a mechanical method and is divided into "Bottom-Up" and "Top-down". Bottom-up expansion is when the expansion cone is placed at the bottom of the expandable pipe, and expands from bottom and upwards. Top-down expansion is the opposite, where the expansion cone is placed at the top of the

expandable pipe, and expands from the top and downwards. Hydraulic expansion is when applying hydraulic pressure underneath the expansion cone, which makes the cone be forced to expand the pipe. Scoping expansion is a mechanical expansion as well, and is when the expandable pipe is forced against the expansion cone.
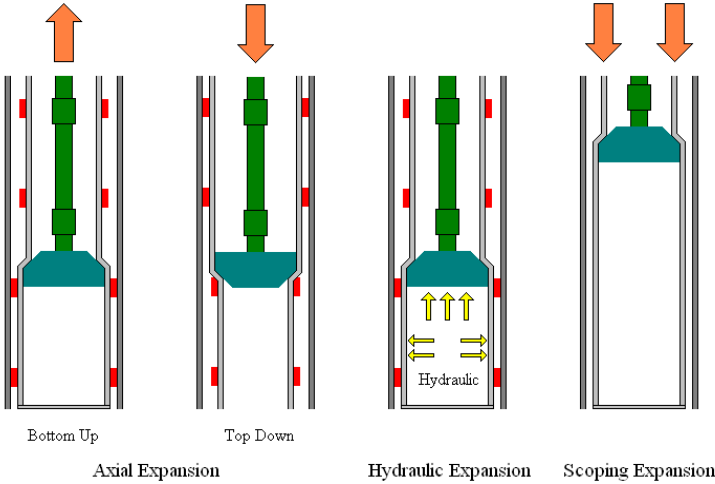
Figure 3.3.2.3: Expansion methods.

The process of expanding pipes is often referred to as cold-working, and is a plastic deformation process that is carried out in a low temperature region and over a certain time interval, such that the strain hardening is not relieved. The cold worked structure forms high dislocation density regions that soon develop into networks, and the grain size decreases with strain at low deformation until a fixed size is reached. Cold-working decreases ductility of the metal.

The opposite, hot-working, is the process where the metals are deformed above their re-crystallization temperature, and strain hardening does not occur.

Historically, collapse tests that has been performed on expanded pipes, show that the collapse resistance is approximately like the conventional API collapse equations, as presented in figure 3.3.2.4. The API collapse strength theory is empirically based and does not consider the residual stress that may be present after the expansion.
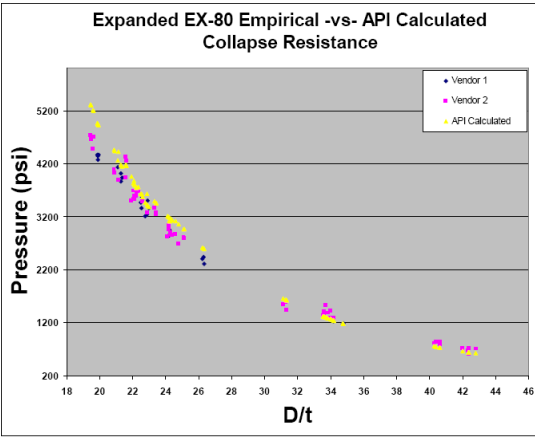
Figure 3.3.2.4: Shows the comparison between collapse resistance of expanded pipes and API calculations with different D/t ratios of a certain steel quality. [Butterfield et al., 2007]

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There are a lot of question regarding expandable pipes, like how does the properties of the pipe change, does the pipe harden, and does the resistance against H_2S and CO_2 change? The most common concern is the effect of the collapse and the H_2S resistance after the expansion. There are certain disadvantages with use of expandable technology. One of them regards the elastic limit of the tube. When the expansion exceeds above a certain percent of the initial diameter, it may cause fracture due to stress in the tubes.

3.3.3 Stress and Strain

The steels that are used in casing are quite mild and have a low linear elastic limit, but the strainhardening capability is extended. Overall, once the material has reached the initial yield stress, the external tensile load is increased further to a stress level equal to σ_y', and the compressive load is decreased to a level equal to σ_{yc}'. This lowering of compressive yield stress associated with tensile yield is called the Bauschinger effect, as showed in figure 3.3.3.1.
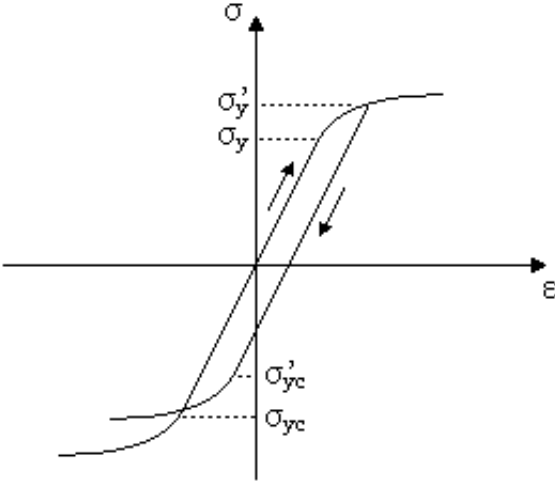
Figure 3.3.3.1: Show the Bauschinger effect. Modified from [Pattillo and Winters, 2009]

The metal hardens from expansion, hence the yield and burst ratings improve but with a related decrease in collapse resistance per the Bauschinger effect. The amount of hardening is a function of the percent expansion and the stress-strain curve of the material. When expanding a pipe, the yield strength of the material is increasing, and since the burst resistance is depending on the yield strength, it would not decrease as much as the collapse resistance which is not depending on the yield strength.

The expansion process of a pipe is dependent on the situation of the pipe. If both ends are fixed, there will be no change in the length of the pipe and the wallthinning would be at a maximum. A fixed end could be a closed end, stuck point or subjected to a high axial friction. If at least one end is free, then there is a combination of wallthinning and length shortening. If somehow the pipe was expanded with zero wallthinning, the shortening would be at the maximum.

It is the size of the expansion cone that controls the amount of expansion that is applied to the solid expandable pipes. This cone stresses the pipe above the yield limit and into the plastic region, which

gives the pipe a permanent deformation. The expansion is successful if the stresses do not exceed the ultimate strength of the pipe, which will result in failure, as showed in figure 3.3.3.2.
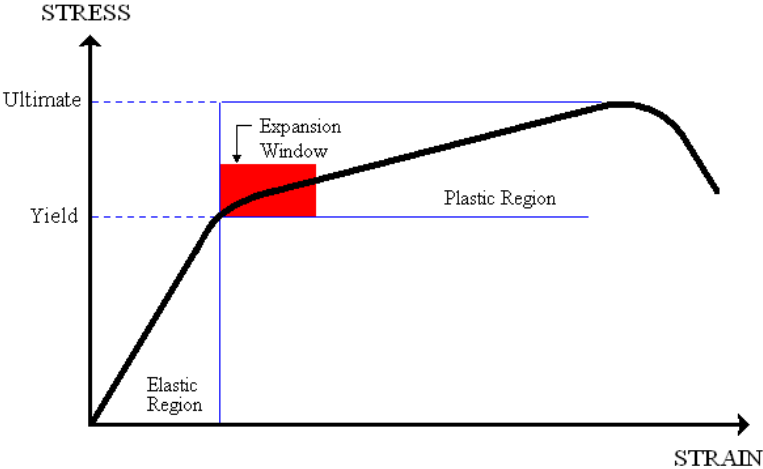
Figure 3.3.3.2: Shows the expansion window that is created from the relationship between stress and strain. Modified from [Campo, 2003]

The formability of the pipe material is usually below 30% expansion ratio [Campo, 2003]. If the pipe extends above this value, failure will occur. This is important to have in mind when determining realistic expansion sizes.

Securing the liner in the wellbore by expansion alone, the limiting expansion ratio of the pipe would in some cases be exceeded. Therefore, cement must be used to seal the annular area between the expanded pipe and the wellbore.

In table 3.3.3.1, show an overview from Enventure's Solid Expandable Technology (SET®) Systems, when expanding a $9\frac{5}{8}$" casing into a $11\frac{3}{4}$" liner, and a $7\frac{5}{8}$" liner inside a $9\frac{5}{8}$" liner or casing. The design collapse strength is calculated with 99.5% reliability, and is decreased a lot from original collapse strength, but not that much on burst resistance (API Yield). These numbers is calculated with a safety factor of 13%, and is quite conservative if using own safety factor in addition as well. [Enventure, 2009 a]

Table 3.3.3.1: Show an overview from Enventure's Solid Expandable Technology (SET®) Systems, when expanding a $9\frac{5}{8}$" casing into an $11\frac{3}{4}$" liner, and a $7\frac{5}{8}$" liner inside a $9\frac{5}{8}$" liner or casing. [Enventure, 2009 a]

Base Casing				SET Systems										
OD	Weight	ID	Drift	Pre-Expansion			Initial Wall	Launcher OD	Post-Expansion			Exp. Ratio	API Yield	Design Collapse
(in)	(lb/ft)	(in)	(in)	OD	ID	Wt	(in)	(in)	OD	ID	Drift	(ID)	(Psi)	Strength*
				(in)	(in)	(lb/ft)			(in)	(in)	(in)			(Psi)
11.750	65.0	10.682	10.625	9.625	8.921	36.0	0.352	10.616	10.650	9.975	9.875	11.8%	4570	1340
9.625	53.5	8.535	8.379	7.625	6.875	29.7	0.375	8.379	8.427	7.710	7.633	12.1%	6130	2740

3.3.4 Advantages and Disadvantages

Advantages and disadvantages of using expandable pipes are presented in the table 3.3.4.1 below.

Table 3.3.4.1: Advantages and disadvantages with expandable pipe.

Advantages	Disadvantages
• Need smaller amounts of drilling fluids. Reduced hole size minimize the use of drilling fluids and cement • Savings in wellhead cost because of smaller surface hole. A smaller wellhead is generally cheaper, easier to transport and less complex • Shorter time needed to circulate. The reduced hole size also reduce circulation time • Smaller bits, reduced size of top-hole reduces size of drill bits. • Loss in hole charges, for example smaller amounts of steel needed • Platform cost, for example less storage are needed • Increase in ROP because of smaller bit is needed	• Decreased collapse resistance • Decreased burst resistance • Most likely have to be combined with cement • Need oversized shoe on the previous casing to keep the drift ID

3.3.5 Monodiameter Drilling Liner

Expandable tubular technology makes it possible get a well with the same diameter throughout the whole well. This is called a monodiameter well. Instead of installing smaller and smaller casings as the conventional method, open-hole reaming below the last set casing provide a larger hole diameter and makes it possible to expand the next casing to the same diameter as the last casing, as illustrated in figure 3.3.5.1. The open-hole reaming below the last casing shoe could be reamed simultaneous as drilling the next section with an under-reamer, or after drilling the hole section.
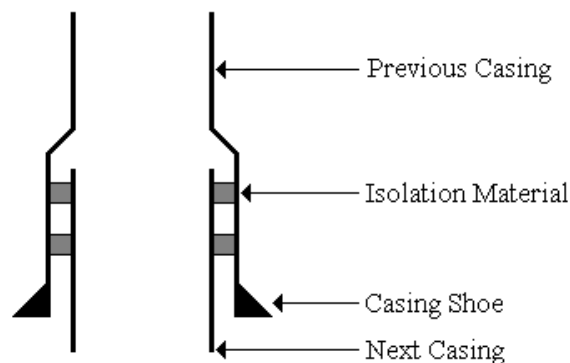
Figure 3.3.5.1: Illustration of how two casing overlap each other after the expansion process, called "bell-shape".

An example of a sequence how to install the next casing is illustrated in figure 3.3.5.2. Figure 3.3.5.2a is after drilling the $8^1/_2$" section. Figure 3.3.5.2b is after reaming the $8^1/_2$" section to a $12^1/_4$" section. Figure 3.3.5.2c show a liner with a smaller OD size than the ID of $9^5/_8$" casing, before it is being expanded. Figure 3.3.5.2d show after the liner is expanded to the same diameter as the $9^5/_8$" casing.
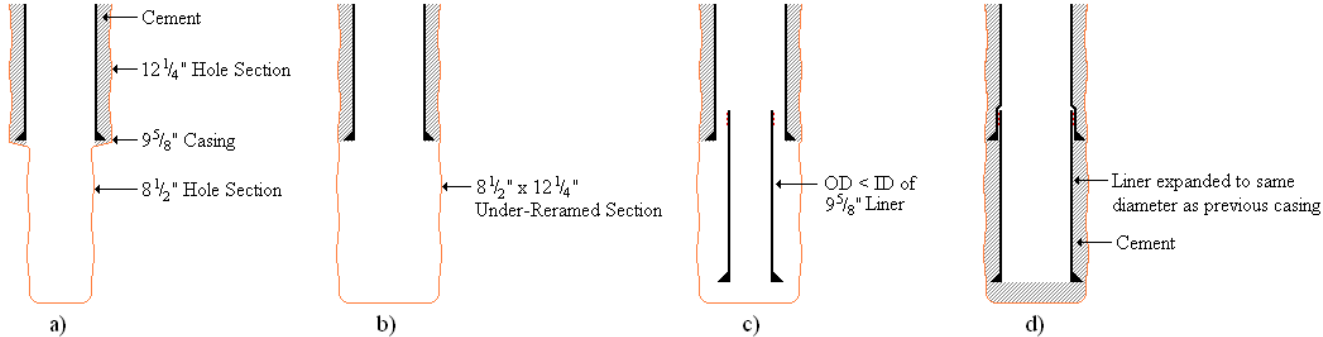
Figure 3.3.5.2: An example of a sequence how to install the next casing.

To create these bell-shaped ends is one of the challenges with a monodiameter well because to re-expand the previous casing or conventional casings may lead to problems. There is a limit to how far the pipe can be expanded, and because of these bell overlaps the previous casing needs to be expanded more than the next casing. In this case there is important that the previous casing not exceed the yield strength of the material, [Campo, 2003].

3.3.6 Advantages and Disadvantages

Advantages and disadvantages of using monodiameter drilling liner are presented in the table 3.3.6.1 below.

Table 3.3.6.1: Advantages and disadvantages with monodiameter drilling liner.

Advantages	Disadvantages
• The emissions are decreased • The consumption of natural resources is decreased • Required size of the drilling Vessel is decreased • The volume and the cost of well constructions consumables is decreased • Disposal of fluids and cuttings • Synergy with intelligent and multilateral well construction • Economic development of smaller reserves field and deeper reservoirs	• Open-hole reaming the whole section below the previous casing could be expensive • When expanding previous casing, the yield strength of the pipe could be exceeded

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3.4 Drilling with an Expandable Liner Hanger

Expandable liner hanger has not been used on Valhall yet, but is planned to be used in near future wells. This technology has been included in this thesis for investigating because it has a potential to improve the barrier at the top of the drilling liner instead of conventional liner hanger used today.

3.4.1 General Principle

Expandable liner hanger is a newer method compared to the conventional liner hanger. The liner hanger is used to create a seal between the liner hanger and the previous casing or liner. The expandable liner hanger system is operated by using a hydraulic setting tool that pressures a cone down a mandrel, and expands the liner hanger outwards to the casing.

Conventional liner hangers have several moving parts while an expandable liner hanger is a much more simplified system that has dual functionality, a hanger and a sealing element.

When using conventionally liner hanger with a drilling liner, the hanger isolation packer and the slips are not installed until after the rotation is stopped. Halliburton has successfully used an expandable liner hanger along with a drilling liner at the Brutus field, Green Canyon Block 158 in the Gulf of Mexico [Mota et al., 2006]. This expandable liner hanger allows to attaching the liner and setting the element at once after stopping the rotation. Halliburton's expandable liner hanger uses elastometric elements to carry the load of the hanger and provide a seal between the liner hanger and the previous casing, as illustrated in figure 3.4.1.1. Other vendors may use other kinds of sealing element.
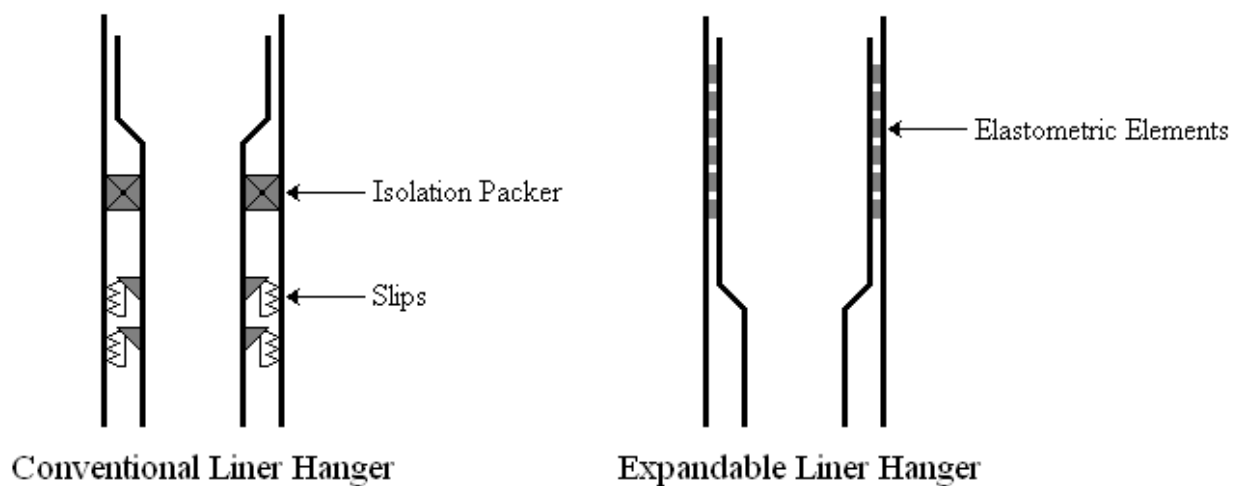
Figure 3.4.1.1: Comparison between conventional liner hanger and an expandable liner hanger. This example shows Halliburton's expandable liner hanger system with elastometric elements as sealing element. Modified from [Mota et al., 2006]

The expandable liner hanger system removes or reduces several risks compared with a conventional liner hanger system used with a drilling liner. Some of them are as presented in the E&P article [Mota et al., 2006]:

- The smooth outer diameter allows faster circulation and better holecleaning with less back pressure.
- The lack of external components removes traps for cuttings and debris, reducing ECD and preventing damage to the hanger and the packer prior to getting to total depth.
- The packing system is hydraulically set, and removes the need for set down weight.
- The setting tool annulus is completely sealed off against ingress of debris.
- The hanger is unaffected by pressure surges while reaming or drilling. The setting tool is unaffected by drilling pressure.

3.4.2 Advantages and Disadvantages

Advantages and disadvantages of using expandable liner hanger are presented in the table 3.4.2.1 below.

Table 3.4.2.1: Advantages and disadvantages by using expandable liner hanger.

Advantages	Disadvantages
- Reduce the rig time because of less RIH time - The running/setting tool assembly features a primary and secondary releasing system for higher reliability - Create sufficient seal integrity and hanging capability with a small length of drillpipe - Has a higher torque rating than conventional liner hangers - Qualified as a barrier element - No moving components left in the well that result in better reliability and fluid flow - Remove the isolation packer at top of the liner which simplify the operations and reduces the complexity - Remove potential cement squeeze jobs - Can be rotated and reciprocated while running in the hole or during cementing operations - Setting sleeves is designed to allow easy passage of amongst other mills, wireline tools and bits - Remove the risk of slips damage to the supporting casing	The running tool cannot be released from the liner hanger before the cement job. Conventionally, the running tool is released before the cement job

3.5 Swellpacker from Easywell

Swellpacker from Easywell has been used on Valhall, but only as zonal isolation inside the reservoir. They have been included in this thesis for investigating because they have a large potential to solve the barrier challenge at top of the reservoir on Valhall, alone or in combination with other technologies.

3.5.1 General Principle

Easywell is a small company that started up in 1999 and had a main focus on zonal isolation and reservoir technology, and was acquired by Halliburton in November 2005. Today Easywell is one of the leading companies in swell technology systems, and has installed more than 13,000 different packers around the world in 47 different countries. [Easywell, 2009]

Methods that are being used today as a zonal isolation, like cement, mechanical packers, inflatable's, straddles and solid expendable's, are often very complex, time consuming and a high risk. The swell technology system is very simple and has no moving parts. This reduces risk, increase the production and reduce cost and rig time. This system has a very good reliability also in an open-hole alternative. There are some benefits by using an open-hole alternative compared to a cased hole:

- Contain the wellbore ID in the reservoir compared to a cemented liner.
- There is possible with longer wells with no concerns with a long interval perforating or ECD during cementing long wells.
- Lower impairment of the reservoir (less skin).
- Larger influx area for production fluids.
- Less stress on rock formation that result in higher permeability and porosity.

A Swellpacker is consisting of a base pipe, the rubber element and end rings as showed in figure 3.5.1.1 and is available in many sizes. There are no moving parts in these packers and no service is needed. The way these packers work, is that the rubber element swells when it is exposed to wellbore fluid. The packer adapts to the wellbore and develops an effective pressure seal. This rubber element is self healing and provides long term isolation.
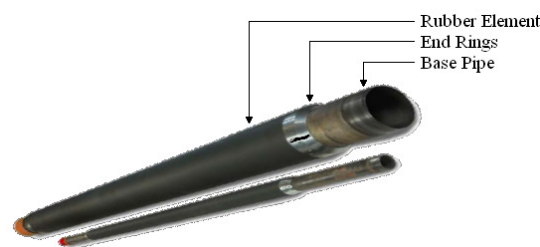
Figure 3.5.1.1: Swellpacker connected to base pipe. [Easywell, 2009]

The Swellpackers can be produced in different types and shapes. The maximum length is usually 9 meters rubber element, since one casing joint is usually 10 meters long. The differential pressure is depending on the length of the rubber element, it is approximately 1,500 psi per meter rubber element. Some of the swell packers are tested up to high temperature and pressure, up to 690 bar

(10,000 psi) and 200˚C (392˚F). These values may be increased because Easywell's present equipment has limitations.

The Swellpacker must not swell more than 115% of its original diameter. If it is swelled more, the packer will not handle high differential pressure and is quite useless. The maximum differential pressure is achieved when the packer is swelled up to 30% of original diameter, which is illustrated in figure 3.5.1.2.
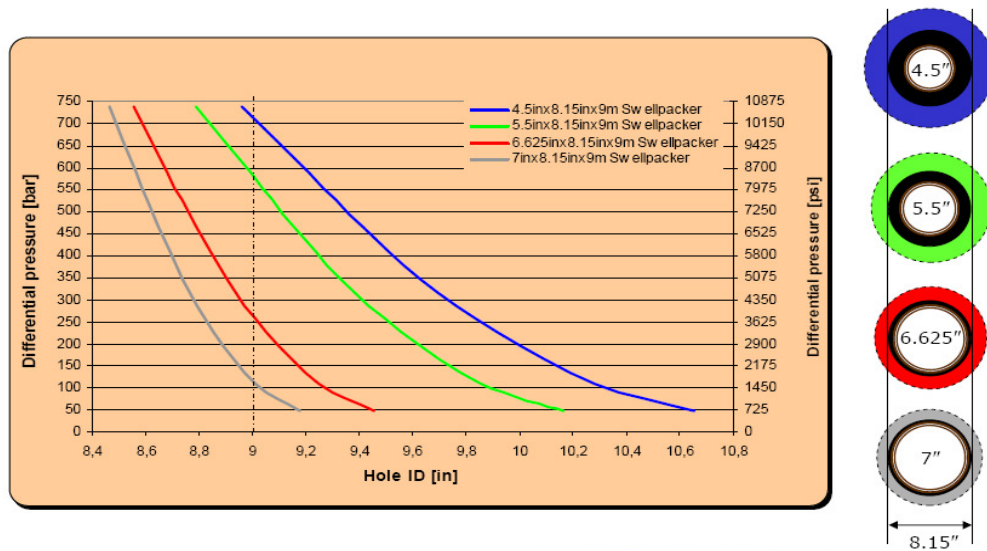
Figure 3.5.1.2: Illustrate the change of differential pressure when the swell percent of the packer is changing at different tubing sizes. [Easywell, 2009]

Easywell can customize the swell packers to meet the customer's requirements by use of simulator software called Swellsim. The demands from the customers may be the differential pressure the packer must hold, swelling volume, rubber element length, and swelling time before seal and operational pressure is achieved. When simulating, the result is presented in different graphs as showed in figure 3.5.1.3.
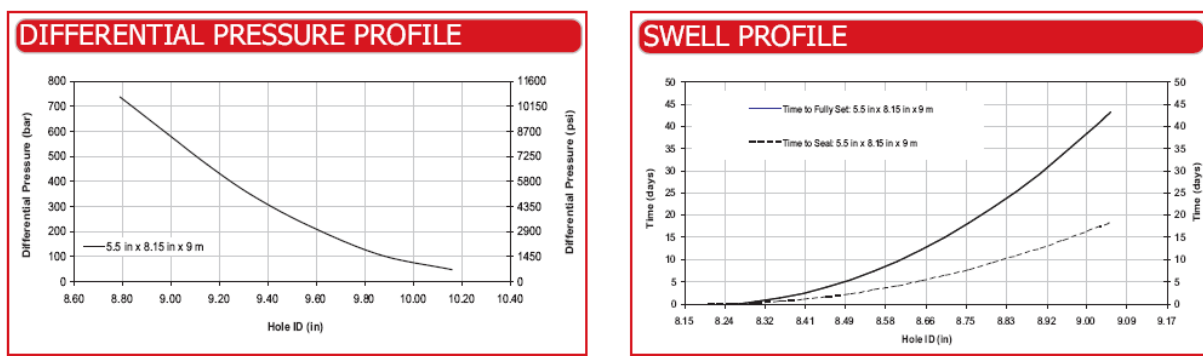
Figure 3.5.1.3: The first graph show a differential pressure profile to the given packer, that show how large differential pressure the packer can hold at a given wellbore ID. The other graph is showing a swell profile to the packer, where the graph show the time before the packer are sealing, and the time before the packer has fully set. [Easywell, 2009]

Easywell deliver many different packers, but there are two main categories which are oil swelling packers and water swelling packers.

3.5.2 Oil Swelling Packers

This rubber swells and expands when it is exposed to hydrocarbon, both oil and gas. This is called the diffusion process, and the hydrocarbon molecules are trapped in the rubber molecular structure. The swelling will continue until the equilibrium is reached if it is allowed to swell freely, and after the swelling is confirmed or restricted, it develops swell pressures inside the rubber. The oil swell system is a one-way process, when the rubber has swelled, it stays swelled.

The rubber starts to swell as soon as it is exposed to hydrocarbon, but it is possible to add a layer outside the rubber element that will delay the swelling process. This has a beneficial among others when the packer is included in the completion and it does not start swelling before the whole completion is set. In figure 3.5.2.1, it is illustrated how the diffusion barrier is placed around the swelling rubber, which has two different rubbers, one low swelling at the outer layer and a high swelling core.
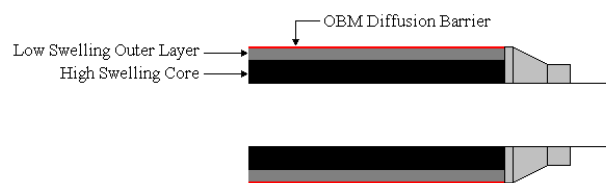
Figure 3.5.2.1: Illustration of how the diffusion barrier is laying around the swelling rubber, which has two different rubbers, one low swelling at the outer layer and a high swelling core. Modified from [Easywell, 2009]

Oil swelling packers must be exposed to liquid hydrocarbons, like oil based mud, base oil, diesel, crude oil, synthetic oil and condensate to get as high pressure integrity as possible. The viscosity of the fluid impacts the swelling speed, if there is a low viscous fluid the rubber swell faster than if the fluid has a high viscosity. If the packer is exposed to gas, the packer will swell but will have much lower pressure integrity. These oil swelling packers will not swell if exposed to water because the polymer in the rubber does not attract water molecules. The packer is stable in both gas and water after swelling in liquid hydrocarbon.

The swell packer system is resistant to chemical attack. Several tests has been done by Easywell where they have exposed the packers to different chemicals that may be present in a well, as scale inhibitors, heavy brines, H_2S, CO_2, organic and non-organic acids.

Temperature impacts the quality of the mechanical properties in the rubber. From laboratory tests, they got following results as showed in table 3.5.2.1.

Table 3.5.2.1: Show an estimated how long an oil swelling packer will last with different bottom-hole temperature. [Easywell, 2009]

BHT [°C]	Estimated Lifetime [Years]
200	10
190	20
180	40
170	80

3.5.3 Water Swelling Packers

This rubber swells and expands when it is exposed to water. This swelling process is based on the osmosis process, where the water is absorbed by polymer/salt impregnated in the rubber molecular structure. The swelling process stops when the salinity level in the rubber is near equal to the fluid salinity that surrounds it, and when the swelling is confirmed or restricted, it develops a osmotic pressure inside the rubber. Compared with the oil swelling system, the water swelling system is a two-way process, which means that the rubber may decrease the swelling if no water is surrounding it.

The water swelling packers may have the same delay system as the oil swelling packers. The swelling speed to the water packers are depending on temperature and salinity. If the water is fresh, the packer is swelling fast, slower if the water increases the salinity. The swelling speed increases in higher temperature as well. In high salinity in water, the swelling volume in the rubber element is reduced as illustrated in figure 3.5.3.1.
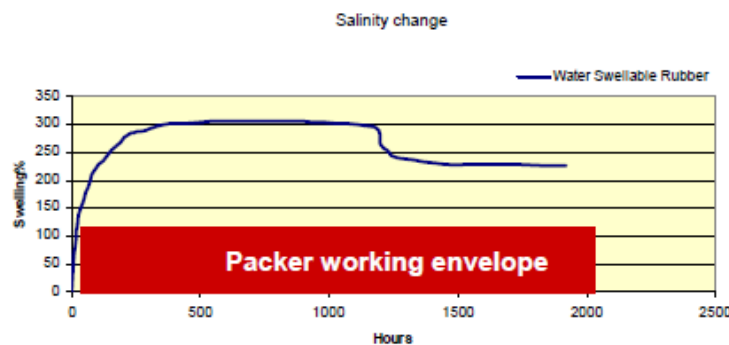
Figure 3.5.3.1: Illustration of how the swell volume reduces when increasing the salinity from 3.6% to 4.2% salinity after 1200 hours. Packer working envelope shows that the packer is working if it is not swelled more than 115% of original diameter as mentioned before. [Easywell, 2009]

The water swelling packers does not swell in hydrocarbons, and is stable in oil after it has been swollen in water. If the gas is fully water saturated the packer will swell.

The water packer is resistant to most of the oilfield chemicals. Several tests has been done by Easywell where they have exposed the packers to different chemicals that may be present in a well, as oil based fluids as diesel, alcohols and methanol, brines and water based mud systems, and different gasses as CO_2 and N_2, but no H_2S, $ZnBr_2$ and strong acids.

Temperature impacts the quality of the mechanical properties in the rubber. From laboratory tests, they got following results as showed in table 3.5.3.1. These values is only theoretical years, and there is no guarantees that the Swellpackers would last that long.

Table 3.5.3.1: Show an estimated how long water swell packer will last with different bottom-hole temperature. [Easywell, 2009]

BHT [˚C]	Estimated Lifetime [Years]
120	20
110	40
100	80

The water packers tolerate only 60% of differential pressure to the oil swell packers, and does not withstand as high temperature.

3.5.4 Combination of Oil Swell Packer and Water Swell Packer

If the wellbore fluid is uncertain, it is possible to run a combination of water- and oil swelling packers, called a dual system as showed in figure 3.5.4.1.
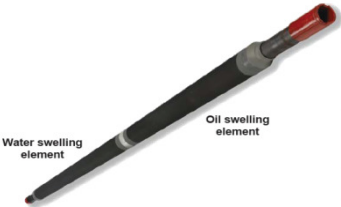
Figure 3.5.4.1: Picture of a dual system with both a water swelling element and an oil swelling element. [Easywell, 2009]

This tool achieves complete zonal isolation and removes the uncertainty regarding the swelling material. The oil swelling part is the same as the oil swelling packer system, and the water swelling part is the same as the water swelling packer system, and it can be used in both open – and cased hole, and is particularly relevant in injection wells.

3.5.5 Advantages and Disadvantages

Advantages and disadvantages about the Swellpackers are presented in table 3.5.5.1 below.

Table 3.5.5.1: Advantages and disadvantages with the Swellpacker from Easywell.

Advantages	Disadvantages
- Perfect seal for irregular borehole geometry - Swelling system can be delayed - Self healing - Easy to install and no moving parts - Alternative solution to cementing and perforating - Reduces the down-hole mechanics and risk - Reduce well cost and rig time - Effectively isolation of producing zones - Low running friction - Applicable for gas and oil wells - Differential pressure up to 690 bar (10,000 psi) - Temperature up to 200°C (392°F) - No loss of well bore or casing integrity	- If a quick zonal isolation is needed, the Swellpacker use too much time to seal - The estimated lifetime of the packers is only theoretically, and has not been proved. - At present day, the Swellpacker is not a qualified barrier element according to NORSOK or ISO standard

3.6 Cement Assurance Tool from Easywell

Cement Assurance Tool from Easywell is the same as the Swellpackers, only as a thin layer around the pipe. This tool has not been tried on Valhall, but is included for investigating in this thesis because it has a large potential so solve the barrier challenge on Valhall along with other technologies.

3.6.1 General Principle

After cementing a casing or a liner, the cement may contract when it sets. This make the cement debond from the casing can create a small passage along the outside the liner where the reservoir fluids may migrate. This small passage is called a micro-annulus and is a problem worldwide. The micro-annulus could be between the cement and the casing, between the cement and the formation or both. Another example of how the micro-annulus is created, is when a casing is cemented and displaced with a high density mud, a reduction to a lighter wellfluid afterwards reduces the internal pressure in the casing. This could then create a micro-annulus between the casing and the cement, as illustrated in figure 3.6.1.1. The well is displaced with a lighter wellfluid when drilling the reservoir section. A Cement Assurance Tool will provide a hydraulic seal between the cement and the casing, because it is a small rubber layer outside the base pipe that will swell when hydrocarbon tries to migrate through micro-annulus as illustrated in figure 3.6.1.2.
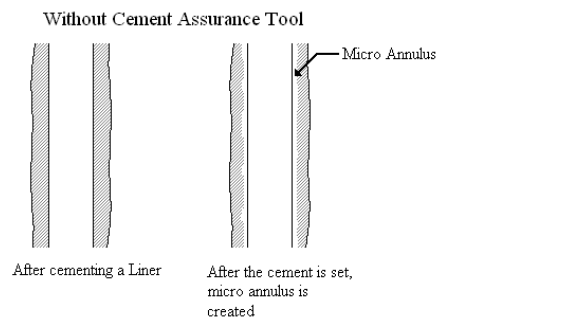
Figure 3.6.1.1: A micro-annulus is created after the cement has set, where the reservoir fluid may migrate.
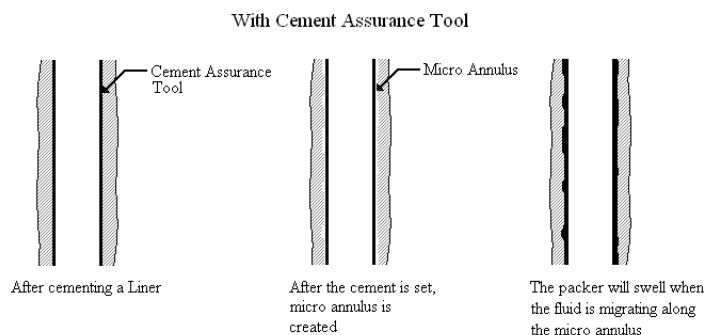
Figure 3.6.1.2: How Cement Assurance Tool will close the micro-annulus and prevent migration of reservoir fluids after a micro-annulus is created.

The Cement Assurance Tool is installed outside the casing as showed on figure 3.6.1.3. This tool is often set above zones where there is most likely to flow liquids or gas, and between different zones

to prevent cross flow. This tool may be used in horizontal sections due to poor cement jobs at the low side, because the rubber will seal where the cement did not seal, as illustrated in figure 3.6.1.4.

Figure 3.6.1.3: Show a picture of a Cement Assurance Tool, [Easywell, 2009]
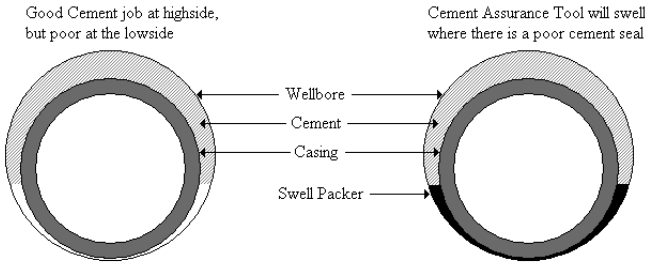
Figure 3.6.1.4: Cement Assurance Tool will seal of the lowside where the cement does not seal in horizontal sections.

3.6.2 Advantages and Disadvantages

Advantages and disadvantages about the Cement Assurance Tool are presented in table 3.6.2.1 below.

Table 3.6.2.1: Advantages and disadvantages with the Cement Assurance Tool from Easywell.

Advantages	Disadvantages
- Available for every size API casing - Designed mainly to the micro-annulus - Can seal irregular geometry in the wellbore - Self healing - Easy to install - No moving parts - Functions in any case of different well type - Match any type of slurry system - Available for both OBM and WBM. - Low running friction - Differential pressure up to 690 bar (10,000 psi) - Temperature up to 200°C (392°F)	- The estimated lifetime of the packers is only theoretically, and has not been proved. - At present day, the Swellpacker is not a qualified barrier element according to NORSOK or ISO standard

3.7 Shale Annular Barrier

There are possibilities that there is a shale annular barrier present at every well on Valhall today. Since this claim is not proved, it is included in this thesis for investigating because if this could be proven somehow, it would definitely be the most obvious solution on Valhall.

3.7.1 General Principle

It has been known that shale formations may collapse against the well and close-of the well in some cases. This happens both during and after drilling through these shale formations. Usually this is a problem, especially regarding the drilling and the casing running, but it could be used as an advantage to the barrier issue of the well by creating an annular barrier outside the casing.

Sonic and ultrasonic azimuthal bond logging usually show information of what is behind the casing. In many of these bond logs, it has showed that there is solid material far above the theoretical cement tops, and correlation with bonding patterns of shale formations indicate that the shale has sealed of the annulus outside the casing.

Pressure testing and logging in sealed of zones in many wells has improved the response of the bond logs for a certain formation, and because of this the logs may supply a better answer of the situation behind the casing, whether the shale has sealed or not. In over 40 wells this technique has been tried with a successful result, which prove that the there is a high quality natural annular barrier that is non-destructive, [Williams et al., 2009].

If the shale should provide an annular barrier, it must have certain physical properties, like sufficient rock strength and a very low permeability to fluids. The displacement mechanism to the shale is very important, as it has implication on whether the formation is able to create an annular barrier or not.

If the shale should perform as an annular barrier, there are several requirements that have to be fulfilled, as presented in [Williams et al., 2009]:

- The barrier must be shale. This can be demonstrated through electrical logs or cuttings description logs made during or after drilling.
- The strength of the shale must be sufficient to withstand the maximum expected pressure that could be applied to it. In practice this means calculating the worst case scenario by extrapolating the maximum reservoir pressure to the base of the expected shale barrier via an annular gas column.
- The displacement mechanism of the shale must be suitable to preserve the well barrier properties.
- The barrier must extend and seal over the full circumference of the casing and over a suitable interval along the well. This can be verified by using wireline ultrasonic azimuthal bond logging tools.

It is several displacement mechanism that occur individual or in combination between them. These mechanisms are, as presented in [Williams et al., 2009]:

- Shear or tensile failure
- Compaction failure and/or consolidation

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- Liquefaction
- Thermal expansion
- Chemical effects
- Creep

3.7.2 Cement Bond Log (CBL) and Variable Density Log (VDL)

These logs are a valuable source of data to determine the effectiveness of the cement sheath surrounding the casing. Both CBL and VDL is a sonic logging tool that has a monopole transducer and a monopole receiver, which is placed a couple of feet from the transmitter, as illustrated in figure 3.7.2.1.
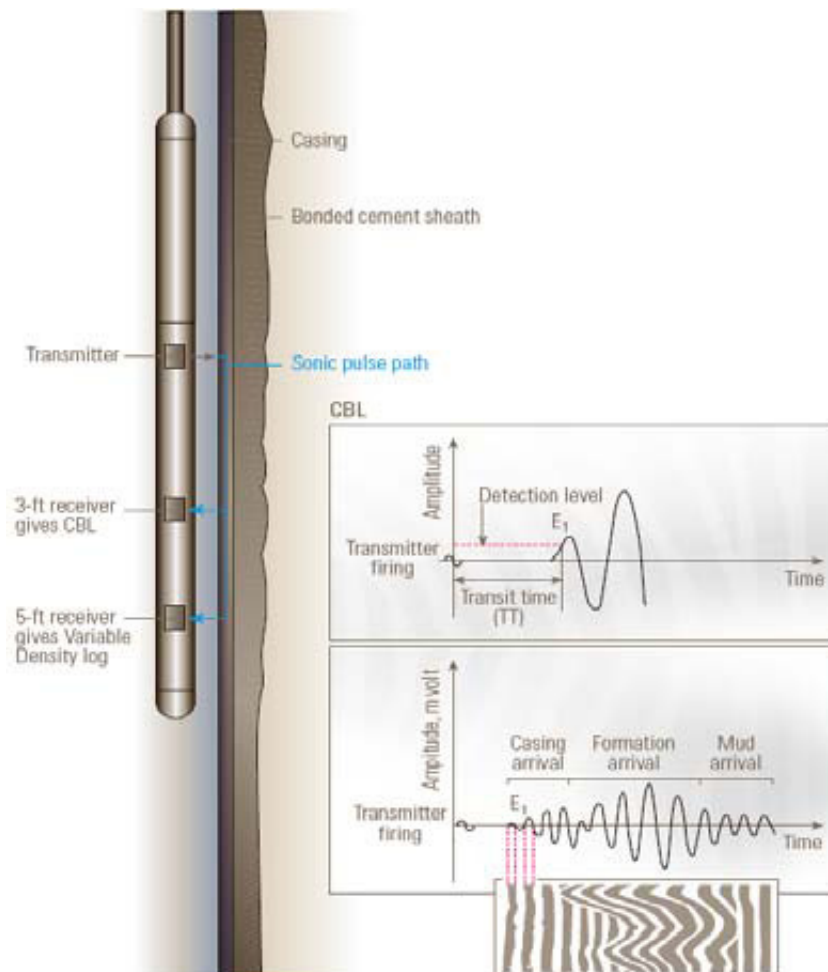
Figure 3.7.2.1: Principle of a Cement Bond Log (CBL) tool, and the how the log respond to the different interval of mud, casing and formation. [Williams et al., 2009]

The transmitter is sending low frequent pulses (10-20 KHz) omni-directional that induces longitudinal vibration of the casing. The recorded data will represent the average values over the circumference of the casing. The amplitude curve of the reflected wave is maximum in unsupported casing and minimum in those sections where the cement is well bounded to the casing and the formation. If these sections are above the cement tops, it means that the shale most likely has collapsed around the casing.

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3.7.3 Ultrasonic Azimuthal Bond Log

This log uses a high frequent pulse-echo technique, and a rotating transducer which send out a broadband of ultrasonic waves. These waves are sent perpendicular to the casing wall to stimulate the resonance mode of the casing. The wave frequency can be adjusted between 250- and 700 kHz, it depends on the wall thickness of the casing, and the amplitude decay which is related to the acoustic impedance of the media on both side of the casing. The acoustic impedance is classified as less than 0.3 MRayl if there is gas, between 0.3 and 2.6 MRayl if there is liquid, and above 2.6 if there is solids. MRayl is a unit of acoustic impedance. Figure 3.7.3.1 show the principle of the Ultrasonic Azimuthal Bond Log, and the how the pulse-echo acoustic-impedance measurements work.
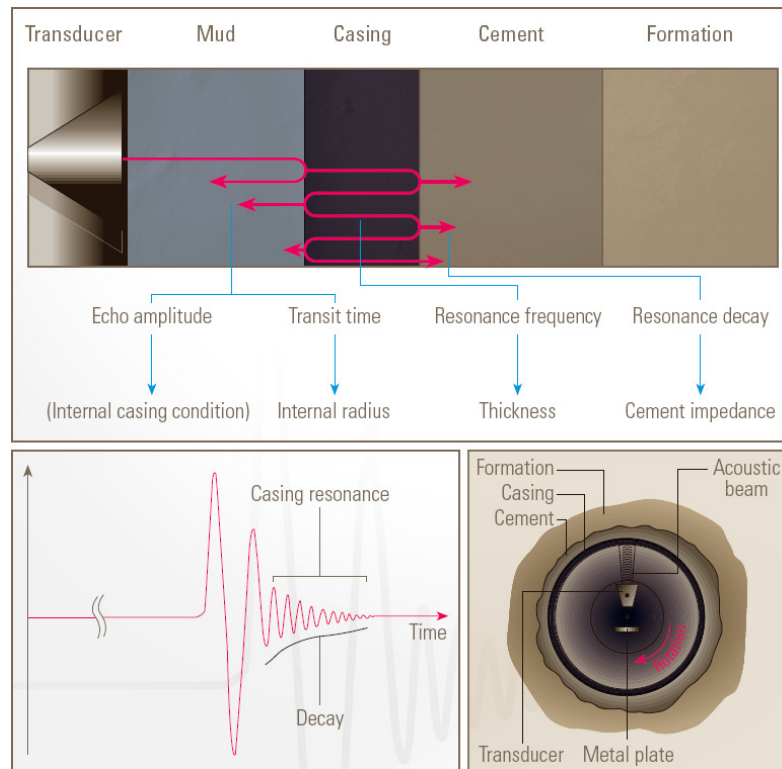
Figure 3.7.3.1: Principle of an Ultrasonic Azimuthal Bond Log, and the how the pulse-echo acoustic-impedance measurement works. [Williams et al., 2009]

To describe the requirement to verify formation as a barrier element, a new steering document was made. This section is as presented in [Williams et al., 2009]:

If competent formation is considered used as a permanent barrier element, position of displaced formation shall be identified and seal ability verified.

Methodology:

- Position and extent of collapsed formation shall be identified through appropriate logs.
- Two independent logging measurements/tools shall be applied.
- Logging tools shall be suitable for applicable well conditions e.g. number of casing strings, casing dimensions and conditions, fluid types and densities.
- Logging tools shall be properly calibrated.
- Logs shall be interpreted by personnel with sufficient competence.

- Log response criteria for good bonding shall be established prior to initiating the logging operation.

Log interpretation:

- Both log measurements/tools show continuous good bonding of minimum 50 meter = Barrier element verified.
- Less than 50 meter continuous good bonding and/or non-unambiguous log response = Verify collapsed formation through pressure test or inflow test.
- No/poor bonding identified. No barrier element identified = Further action to be determined.

In the bond logging responses, the cut-off value has been calibrated against successful pressure tests performed in a number of formations, and has found to be extremely steady in different formations. In table 3.7.3.1, suggestions of readings that can be guidelines are presented.

Table 3.7.3.1: Calibrated bond log values. [Williams et al., 2009]

	Cement bond log amplitude	Variable Density log	Ultrasonic acoustic impedance scanner
Good Barrier	CBL less than 20 mV over 80% of the interval	Low contrast casing signal and clear formation arrivals	AI reading greater than 3 MRayl on all azimuths
No Barrier	CBL reading within 20% of free pipe reading	High contrast casing signal and weak formation arrivals	Reading less than 2 MRayl on some azimuthal readings

3.7.4 Pressure Testing

When the bond logs observe shale behind the casing, it has to be pressure tested to be able to check that the shale strength is good enough to provide a barrier. The pressure test must be performed below or near the base of the potential barrier, and exceed the maximum expected pressure that could be exposed to the barrier. Often the pressure test will be exceeded up to the leak-off pressure to ensure that any possible leakage not occur when applying a lower pressure.

There are several methods to perform a pressure test, and some of them are, [Williams et al, 2009]:

- Perforate the casing at the base of the potential barrier identified from logs. Apply pressure in the well until either a pressure response is seen at the casing annulus at surface, or a leak-off response is seen.
- Perforate the casing at the base and the top of the potential barrier. Then run a test string and packer and set the packer between the perforations. Apply pressure in the test string until either a pressure response is seen at the test string annulus, or a leak-off response is seen.
- Run a cased-hole formation tester with pump-in capability. Make a hole in the casing at the base of the potential barrier. Monitor formation pressure to ensure no connectivity to other

pressured zones. Pump into the hole until leak-off pressure is reached. Repeat the measurement to ensure good quality.

3.7.5 Advantages and Disadvantages

Advantages and disadvantages with a shale annular barrier are presented in the table 3.7.5.1 below.

Table 3.7.5.1: Advantages and disadvantages with the shale annular barrier.

Advantages	Disadvantages
- Create a practical and effective annular barrier - Removes complex remedial work - Removes substantial costs - Prolonged well life in some cases - Improvement in the quality of well integrity - More robust than other man made barriers - Self healing - Extremely durable	- The shale most may not collapse instantaneously, it can take months or even years - Additional expensive logging - To be able to determine if the barrier on the logs is real, the particular formation must be calibrated by pressure testing, which is expensive - The particular formation must be limit tested to determine the formation strength - Can not affect the quality of the shale barrier, like permeability, interval and how good it seals the casing

3.8 ThermaSet from WellCem AS

ThermaSet has not been tried on Valhall, mainly because it is too expensive compared to cement. This technology is included in this thesis for investigation because the ThermaSet is quite much stronger that conventional cement and has a possibility to create a stronger seal behind the liner.

3.8.1 General Principle

ThermaSet is a material that may replace the cement that is used on new wells today. A specific thermosetting liquid is the binding material in ThermaSet, which is a penetrating liquid with a low viscosity. There are no particles in this material that has benefits in injection purposes. The ThermaSet can be customized the way the customer wants it, like density that is regulated with particles, viscosity and curing time. The density varies usually from 0.66 sg to 2.5 sg, as showed in figure 3.8.1.1.
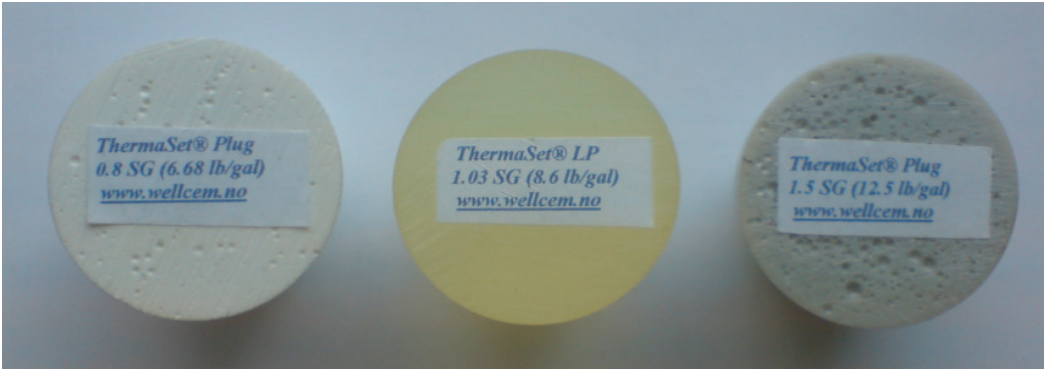
Figure 3.8.1.1: Some samples of ThermaSet with different densities.

Compared with the cement, the properties to the ThermaSet are showed in table 3.8.1.1.

Table 3.8.1.1: Comparison between ThermaSet and conventional cement. [Wellcem, 2009]

Properties	ThermaSet	Cement
Viscosity, Fann (cP) at 20˚C	20 - 30	-
Tensile Strength (Mpa)	60 (8,700 psi)	~1 (~145 psi)
Rupture Elongation (%)	3.5	0.01

Since the ThermaSet has a low viscosity, it can easily be pumped. The tensile strength is 60 times higher than the cement, and the ThermaSet is 350 times flexible. Because of the large different in E-modulus, the ThermaSet is 6-7 times softer than the cement. When the ThermaSet sets, the liquid material will cure to a very hard material.

The cement is not good to use in places where there might be changes in temperature and other physical parameters as compaction. The cement may crack when the steel of the casing is expanding and contracting due to temperature changes, as showed in figure 3.8.1.2. Because of the larger tensile strength and rupture elongation to the ThermaSet, it would not fracture as the cement does.

Figure 3.8.1.2: Cement that is fractured between casing strings after the steel has been heated up and then cooled down. [Wellcem, 2009]

This material can be used in many applications, such as:

- Plugging when abandonment a well
- Stop leaks
- Pressure isolation and reinforcement of zones in the well
- Cure difficult situations of lost circulations
- Repair cracked cement
- Easily close water producing zones

3.8.2 Advantages and Disadvantages

Advantages and Disadvantages with the ThermaSet from WellCem are presented in table 3.8.2.1 below.

Table 3.8.2.1: Advantages and disadvantages with ThermaSet.

Advantages	Disadvantages
- Low viscosity - Reinforce formations - Sets up fast - Can regulate setting time - High tensile strength - Tolerate thermal expansion - Will not fracture - More elastic compared with cement - More ductile compared with cement - Possible to expand	- Very expensive compared to cement - Can fracture the formations if it expand too much

3.9 DuraWAV, Noétic Engineering Inc.

DuraWAV casing has not been used on Valhall. It is included in this thesis for investigation because this is a new technology that makes the casings much stronger than conventional casings due to deformation from stress loads in the formation. DuraWAV could be a solution to make the well last longer.

3.9.1 General Principle

As mentioned, deformation of casing is a large problem in the oil industry, and such cases are increasing every day worldwide. This problem calls for stronger pipes with stronger connections, but stronger materials are often less tolerant of deformation than the weaker but more ductile materials, and the damage mechanism is ground movement. Applications as slip joints and bell-hole, figure 3.9.1.1, has been tried to reduce the loads that develops with forced deformation.
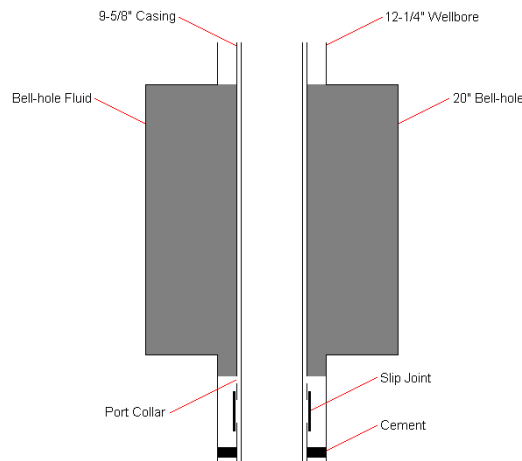
Figure 3.9.1.1: Component of a bell-hole and slip joint. Modified from [Pattillo et al., 1995]

The bell-hole is a larger diameter hole that is reamed, but this application would increase the potential of well instability, especially in high inclined wells. The slip joint is used to achieve the stroke out axial strain at discrete location. This joint has a limited temperature range, high cost, poor seal performance and low bending tolerance. DuraWAV offers the same benefits as the slip joint, but with improved simplicity with no sliding seals and tolerate the same temperature range as the casing string.

DuraWAV is a pipe with a corrugated shape that absorbs the axial strain and provides an increased compliance compared to a straight pipe, and has an increased collapse resistance. The shape of the DuraWAV is created from a straight pipe that is hydro-formed into a wave pattern. Non-linear finite element analysis techniques have been used to optimize the shape of the waves and the wall thickness for specific applications. DuraWAV provides a high pressure capacity, and has a less stiffness than straight pipes, and is made to offer a sufficient strength and stiffness for handling and installation. A sample of DuraWAV is showed in figure 3.9.1.2, and a closer look at the wave shape is showed in figure 3.9.1.3.

Figure 3.9.1.2: A sample of a DuraWAV joint. [DuraWAV, 2009]
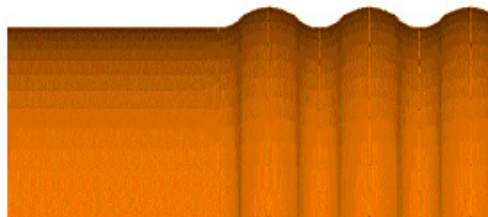
Figure 3.9.1.3: A closer look at the wave shape of the DuraWAV joint. [DuraWAV, 2009]

DuraWAV can be applied in a variety of formats as part of the casing or piping systems, a list is presented in the DuraWAV brochure:

- Casing
- Crush joints
- Expansion joints
- Shear resistance tools
- High torque/pressure flex joints

The principle to the DuraWAV pipe compared to an ordinary straight pipe is showed in figure 3.9.1.4.
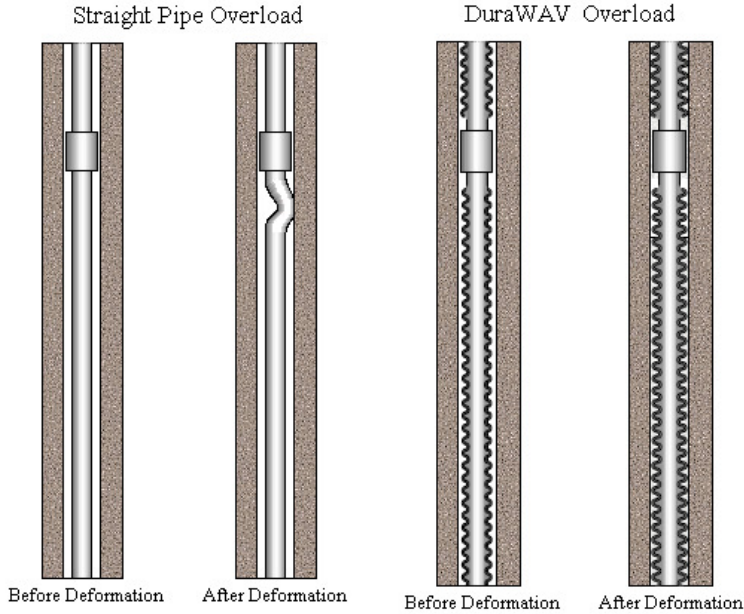
Figure 3.9.1.4: Principle of the DuraWAV compared to an ordinary straight pipe. The ordinary straight pipe will buckle and fail at an unsupported point, while the DuraWAV would compact and remain as an unbroken pipe. Modified from [DuraWAV, 2009]

3.9.2 Advantages and Disadvantages

Advantages and disadvantages with the DuraWAV are presented in the table 3.9.2.1 below.

Table 3.9.2.1: Advantages and disadvantages with the DuraWAV.

Advantages	Disadvantages
• Can handle much more axial load than a straight pipe • Is less stiff than a straight pipe that gives it possible to handle more bending loads, enable it to accommodate high curvature through double bend "jog" shape of the shear zone, without ovalization induced collapse • Improved shear capacity • Improved collapse capacity • Will not fail as easily as a straight pipe during compaction of the formation • Can be included in many different casing or piping systems • Performance and cost benefits	• This technology has not been tried out in any of BP's installation yet, and is probably not easy to implement instead of the recommended heavy wall casings used today

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3.10 External Sleeve Inflatable Packer Collar (ESIPC)

The ESIPC has not been used on Valhall because this is a tool used with Halliburton's expandable liner hanger, Versaflex, which has not been used. This technology is included in this thesis for investigation because the ESIPC has a special method to cement the liner, and could possibly be a solution to the barrier challenge on Valhall if it is possible to include it in the design somehow.

3.10.1 General Principle of the ESIPC

This collar is delivered from Halliburton, and is a combination of their ES (Type P or Type H) cementer and a casing inflation packer. The ESIPC give a controlled inflation to the packer element through the stagetool opening seat, which removes hydraulic valving bodies that usually are located in the inflatable packer.

The rubber element in the inflatable packer has been reinforced with metal slats that reduce the risk of damage of the packer element during inflation. The ESIPC is showed in figure 3.10.1.1.

Figure 3.10.1.1: Halliburton's External Sleeve Inflatable Packer Collar (ESIPC). [Halliburton, 2009 b]

The ESIPC is operated with a standard stage tool plug set. An illustration of how dual bottom-top wipers plug set works is showed in figure 3.10.1.2. Figure a) show how the plug is being installed at the top of the liner. When the liner is set at wanted depth, a ball is dropped and followed with cement as illustrated in figure b). Ball sets in the bottom plug, and the pressure increase makes the bottom cement plug shear from the top cement plug, and start moving downwards, figure c), until it hits the plug seat in the ESIPC, showed in figure d). When the amount of cement is injected, a wiper dart is launched directly after the cement, wiping the drillpipe and launch into the top cement plug, as also showed in figure d). The top cement plug is sheared at a predetermined pressure, and wipes the inner diameter of the liner along with the wiper dart. When the pressure increases at the bottom cement plug, the ESIPC activation port opens, and the cement is inflating the packer, as illustrated in figure e). The pressure is increasing, and some sleeves is shifted open and cement is diverted into the open hole- or liner annulus and upwards, as also showed in figure e). When the wiper dart with the top cement plug is reaching the ESIPC, it closes the sliding sleeves as showed in figure f) and g).
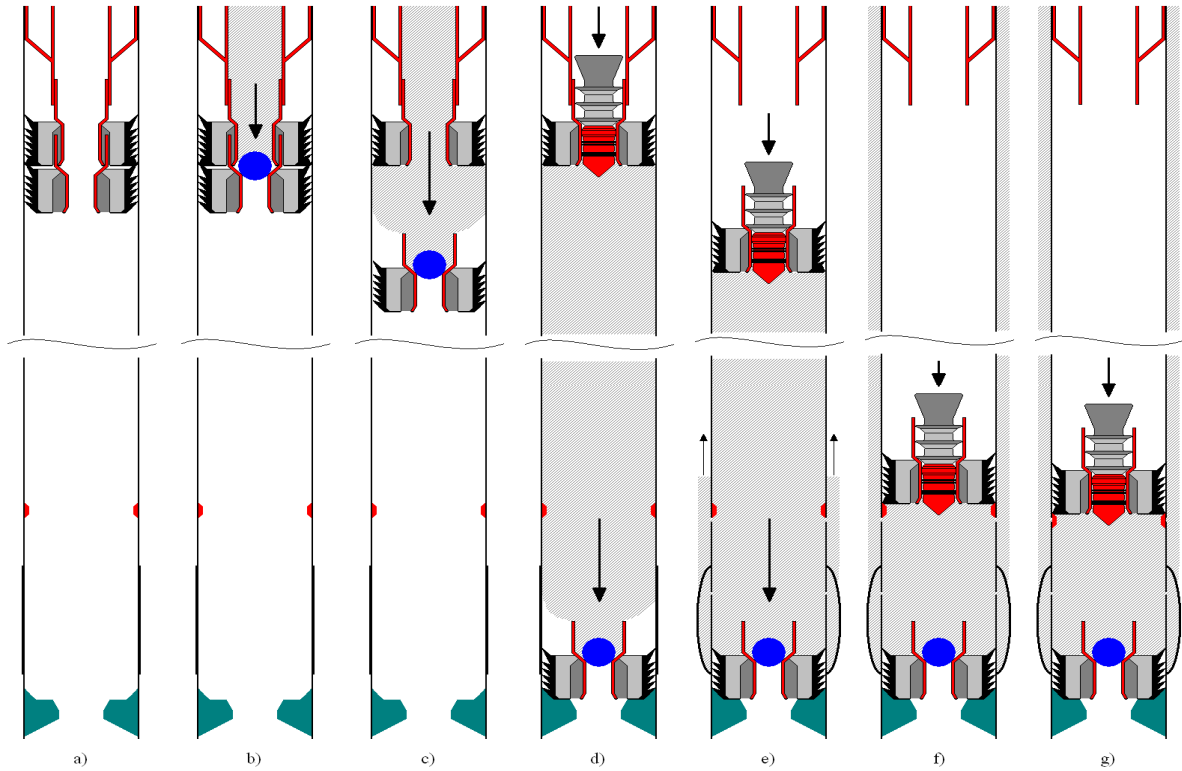
Figure 3.10.1.2: Illustrate the principle how the dual bottom-top wiper plug set works. Modified from [Halliburton, 2009 b]

The inflatable packer can handle a differential pressure up to 4,000 psi, and is commonly used in horizontal wells for cementing the casing. The main purpose to the ESIPC is to seal of the annulus underneath the external sleeve to prevent cement from flowing down-hole when it is pumped into the annulus.

3.10.2 Type-H External Sleeve (ES) Cementer

This external sleeve cementer is a hydraulically opened stage cementer, and can be used in most liner applications. The Type-H is not depending on pressure, depth or temperature, and it works by applying hydraulic pressure down the drillstring after a first-stage shutoff plug lands in the sleeve. By using this external sleeve collar, it is not necessary to drop a free-fall plug from the surface, but a baffle adapter may be used in the casing string above the float collar to set the first-stage shutoff plug. Figure 3.10.2.1 is showing how a Type-H External Sleeve Cementer looks like.
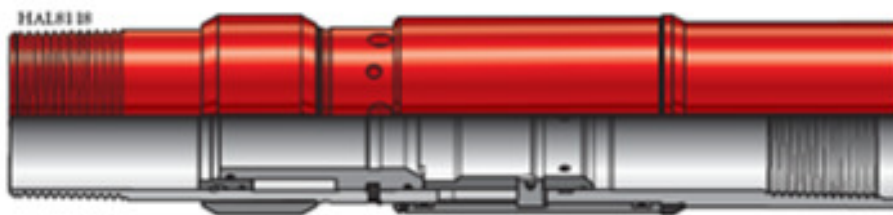
Figure 3.10.2.1: Type-H External Sleeve (ES) Cementer. [Halliburton, 2009 b]

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3.10.3 Casing Inflation Packer

This packer uses a kind of inflatable bladder that expand the packer element against the wellbore or the casing. To set this packer, a ball is dropped to create a seal following by applying hydraulic pressure from the surface to inflate the packer with cement. These kind of packers have a capability to expand in large ratios, that is a very important factor if the packer is set in a large wellbore.

3.10.4 Advantages and Disadvantages

Advantages and disadvantages of using ESIPC are presented in the table 3.10.4.1 below.

Table 3.10.4.1: Advantages and disadvantages with the ESIPC.

Advantages	Disadvantages
• Reinforced metal slats that reduces the risk of damaging the packer element during inflation • The inflation of the packer is controlled through the stagetool opening seat, and which removes hydraulic valving bodies that usually are located in the inflatable packer	• Is designed to be used with the Versaflex expandable liner hanger, in stable environments and without any high torque rotation

4 Valhall Case Study

The following sections are investigating of the current operational procedures, as the drilling sequence of new wells and the calculation of injection pressure. Different combinations of different technologies, and how to include them in the current casing design, are investigated as well.

4.1 Today's Procedure at Valhall

Different methods and technology has been tested with varying success at Valhall. One of the methods used since 1993 on DP, WP and IP because of the low reservoir pressure, is the use of drilling liners to drill into the reservoir. Originally, as the easiest option, one could drill the hole from the production casing down to above the Tor formation and cement conventionally as illustrated in figure 4.1.1. Then there would be two barriers that are the Lista formation, and the cement in the annulus between the production casing and the Lista/Paleocene. This method was used before the drilling liner was introduced at Valhall. Disadvantages with this design at Valhall, is that the $9^5/_8$" casing is set above the Tor formation while it is recommended set the casing shoe inside the reservoir to maintain the casing size. By setting the $9^5/_8$" casing above the Tor formation, a smaller sized liner has to be used inside the reservoir, which is a disadvantage due to long horizontal sections. Because of the pressure depletion in the Tor formation, it is a risk of losing circulation during drilling into this formation. By using drilling liners, one has been successful in reducing the large losses and has a large economical benefit. Another benefit from using a drilling liner compared to the previous design is to avoid cavings from the Lista formation when drilling into the Tor formation. There may be cavings because the low mud weight needed to avoid losses in Tor is too low for stability in Paleocene.
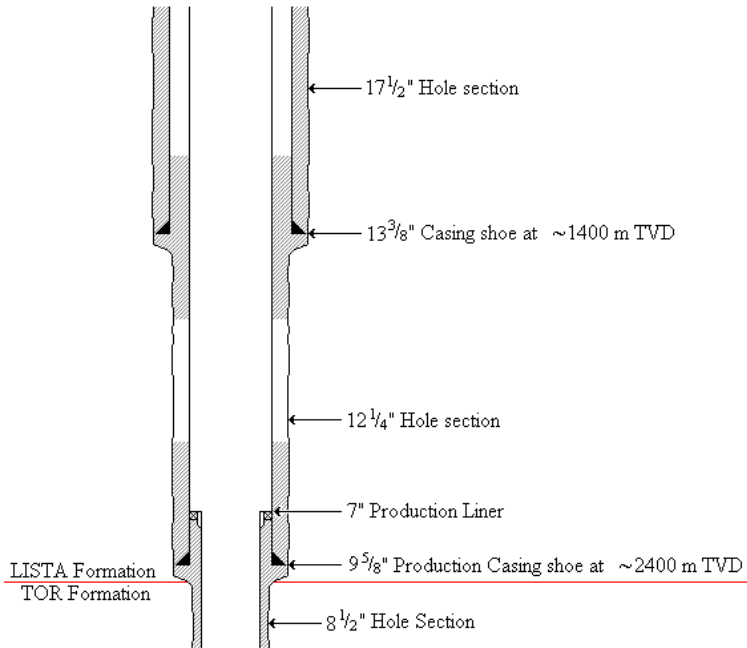
Figure 4.1.1: Original method on where to set the different casing sizes.

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The most recent procedure using drilling liner has been to drill a $17^1/_2$" section down to approximately 2,100 meters TVD and set the $13^3/_8$" casing shoe in this area. The next step is to drill the $12^1/_4$" section down to between 5 and 10 meters TVD above the Tor formation as showed in figure 4.1.2a. The last meters down to the reservoir and into the reservoir are drilled with $9^5/_8$" drilling liner. The mud weight used during drilling the Lista formation normally ranges between 14.6 ppg to 14.9 ppg for stability. The pore pressure gradient in the Lista formation is approximately 14 ppg, and 7 ppg in the Tor formation and this large difference meaning a pressure differential of approximately 3,000 psi. When entering the Tor formation, this large difference in pore pressure results in large losses close up to 100% of ~1,000 barrels of mud each hour, [Baden, 2009]. As illustrated in figure 4.1.2b, the losses are in the inside and outside of the liner.
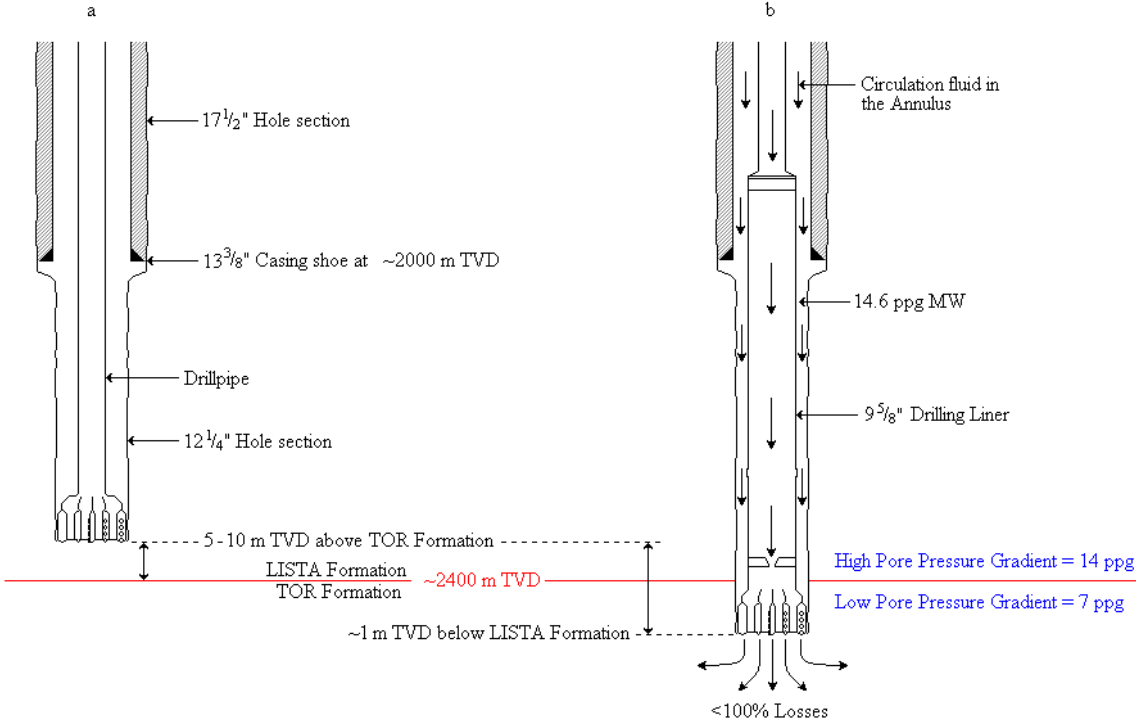
Figure 4.1.2: The first part of the procedure used today.

When drilling into the Tor formation with a drilling liner, it often gets stuck a few meters below the Lista formation, which mean approximately 1 meter TVD since the inclination of the well is often between 66-68˚. The reason for this is uncertain but it is believed that the Lista formation is collapsing around the drilling liner, or it could be a result of differential sticking in the Tor formation because of the large pressure difference. Earlier stability test of the wells often showed that there has to be at least ~14.8 ppg to stabilize the Lista formation shale in wells with a high inclination. Due to large losses, the effective hydrostatic pressure of the mud is decreasing below 14.8 ppg, and this may result in Lista formation collapse. If the zonal isolation is not in place, putting the well on production may create zonal isolation across the open shale interval as the flowing bottom-hole pressure is reduced. This can be illustrated with a rock mechanics equation, [Kristiansen et al., 2008]:

$$U_d = \frac{\sigma_h - P_w}{2G} \frac{R^2}{r} \qquad\qquad (4\text{-}1)$$

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where U_d is radial displacement, σ_h is the horizontal stress, P_w is the well pressure, R is the wellbore radius, r is the radial coordinate and G is the shear modulus that may be a function of time and well pressure. Figure 4.1.3 illustrates the hole-closure equation above.
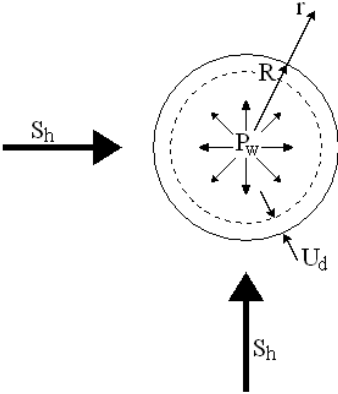
Figure 4.1.3: Illustrates the hole-closure from the equation above. [Kristiansen et al., 2008]

When the Lista formation is closing around the drilling liner, the loss of mud in the annulus is decreasing, if there is any mud left, as showed in figure 4.1.4a. Once the drilling liner is stuck, the first priority is to stop the losses. A ball is dropped into the drillstring as illustrated in figure 4.1.4b. This ball lands on a ballseat at the bottom of the liner and stops the losses inside the liner. The ball used has been in bronze, but a less weighted ball such as aluminium is considered to reduce the force on the ballseat. The next step is to set the hanger packer on top of the drilling liner and pull the running tool and the drilling pipe connected to the liner as showed in figure 4.1.4c. The well is then sealed against the formation independent if the Lista formation has closed onto the liner or not.
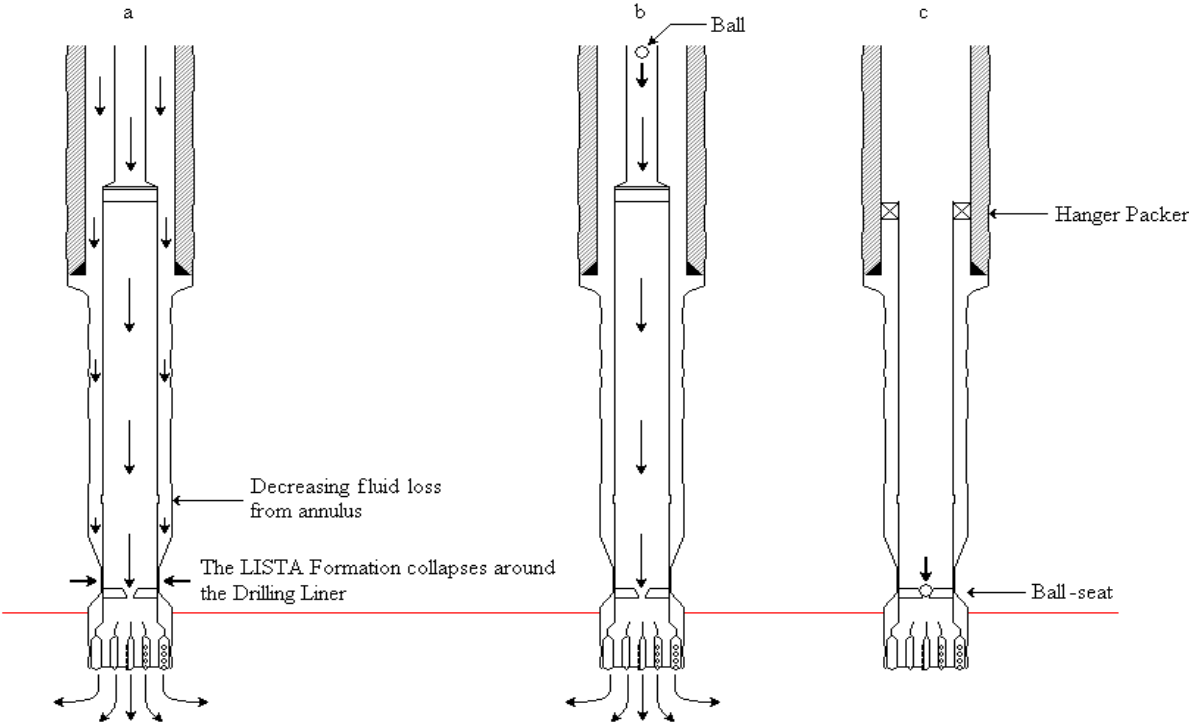
Figure 4.1.4: The second part of the procedure used today.

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After sealing of the well from the reservoir with the ball and the hanger packer, cement is squeezed through the port collar as showed in figure 4.1.5a, and the $8^1/_2$" reservoir hole section is then drilled as showed in figure 4.1.5b. The port collar is located approximately 40 meters from the bit.
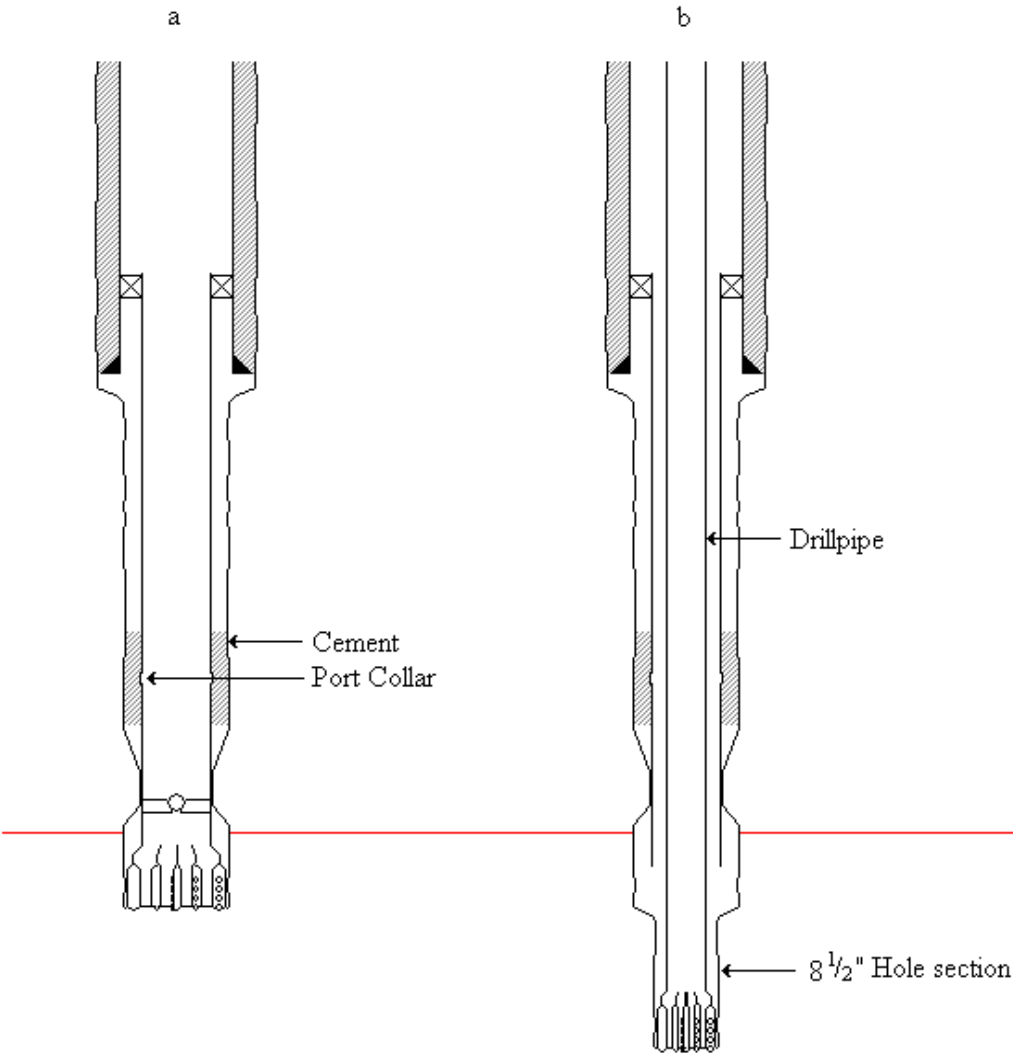
Figure 4.1.5: The third part of the procedure used today.

The quality of this cement job through the port collar is questionable and is not approved as an adequate barrier according to NORSOK. The reason is that there is no confirmation that the cement is placed where it is required, therefore it must be assumed that the there are no cement between the formation and the drilling liner as a worst case scenario.

When squeezing cement like this, the cement may flow into fractures in the Lista formation, or squeezed into the Tor formation if the Lista formation has not collapsed around the liner. This is illustrated in figure 4.1.6. If there is not a good cement sheet between the Lista formation and the drilling liner, the barrier elements is the cement located around the $13^3/_8$" casing shoe in the Eocene Shale.
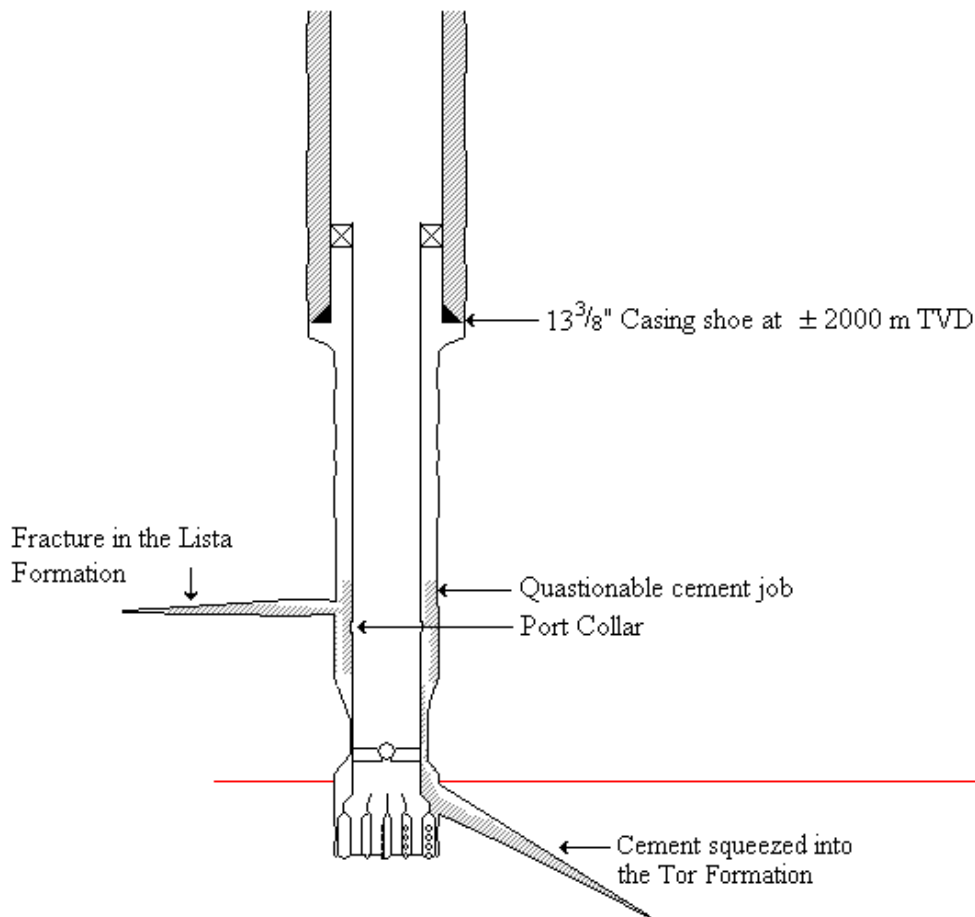
Figure 4.1.6: Illustration of where the cement could go if the Lista does not collapse around the drilling liner, either in a fracture in the Lista or in the reservoir.

In the G-10 well on Valhall IP, a Cement Bond Log (CBL) was run in the $9^5/_8$" liner, and this log showed that there was approximately no cement behind the liner. This is perhaps the reason that there has not been run several logs in other wells, the probability that there is no cement behind the liner is large anyway.

The current designs at Valhall is mainly focused on getting the wells into the reservoir, and make the wells withstand the shear deformation in the overburden and shallow high pressured zones. The concerns about the pressure integrity to the barriers, as well as the abandonment of wells have increased recently. The reason for this concern about the pressure integrity is that the waterflood through the injectors is not optimized. As long as there is no confirmed well barrier at top of the reservoir, the injection pressure cannot exceed the fracture pressure at the $13^3/_8$" casing shoe at ~2,100 meters TVD, to avoid fracturing the formation. This affects the recovery one can get from waterflooding.

4.2 Calculations Used t Valhall

At Valhall, some of the producer wells have been converted to injectors. In these wells, there will be high grade of compaction near the wellbore and reduced permeability that will negatively impact the injectivity. In order to optimize injectivity, it is not recommended to pre-produce the injectors, [Kristiansen et al., 2008].

In the beginning of the water injection project at Valhall, there was recommended a 500 psi safety margin on the injection pressure compared to the minimum horizontal stress in the caprock (Lista formation). This was to avoid reopening and propagation of high pressure fractures in this formation, which is a general requirement. A safety margin of 500 psi would be a good starting point in order to account for uncertainties that may be in place due to subsidence.

As mentioned before, the LOT point indicates the initial stage of fracturing of the rock. After the peak pressure that is called the breakdown pressure, there will be a drop to the propagation pressure, which is the pressure needed to extend the fracture and is slightly higher than the minimum horizontal stress. After shutting off the pumps, the closure stress is found when the flow regime goes from linear in the open fracture to radial when the fracture is closing. When running the leak off test one more time, the main difference will be the decreased peak pressure because the tensile strength of the rock is lost if the rock was intact before the first test. This test sequence, when increasing the pressure more than the LOT, is called extended leak-off test (XLOT) and is performed on every resent well on Valhall IP below the $13^3/_8$" shoe to verify the integrity of the shoe.

In figure 4.2.1, the extended leak-off test illustrates the relationship between different pressures that is related to fracture propagation in rocks.
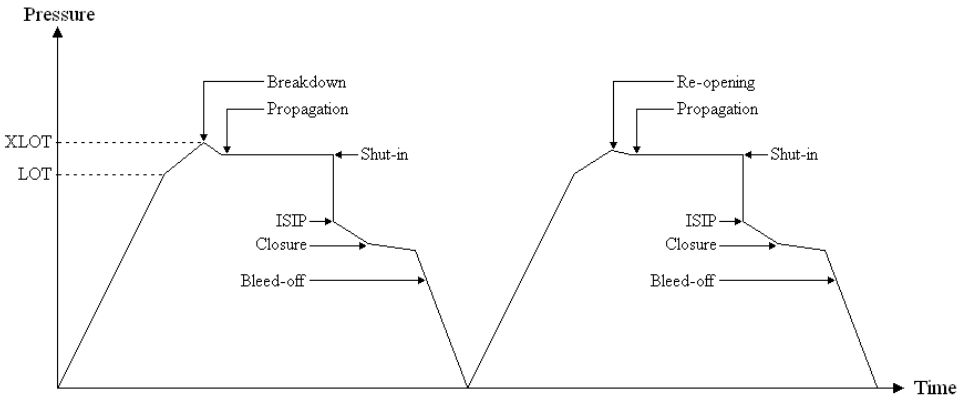
Figure 4.2.1: The Extended leak-off test with two cycles, and show relationship between different pressures that is related to fracture propagation in the rocks. [Kristiansen et al., 2008]

In one of the produced water injectors on Valhall WP, F-7, there has been performed several "boost test" where the injection pressure has exceeded the closure stress of the Lista caprock. From surveillance data and field indications, it seems that even if there has been a fracture during a limited time, the water remains in the reservoir as long as the injection pressure is kept below the leak off pressure in Lista, [Kristiansen et al., 2008].

A reason for this may be the large amount of smectite according to core samples from the Lista formation. The smectite may heal the fractures made by the injection quite efficiency and may due

to swelling increase the closure stress locally in the cap rock. It is recommended to have a "boost test" when approaching the limiting pressure for a short time to promote swelling, and then operate the injection pressure using a new safety factor of 250 psi, [Kristiansen et al., 2008].

To improve the waterflood economics by a certain minimum, a modified procedure is recommended to be used on Valhall. In this procedure [Kristiansen et al., 2008], the well should continue to follow the initial pressure limit given by:

$$P_{max} \text{ Tor (500 psi margin) [psi]} = (2,5333 \text{ x Depth}_{m\,TVD\,MSL}) - 183,33 \qquad (4\text{-}2)$$

which is a correlation with a safety margin of 500 psi. When the injection pressure is equal to this pressure, the injection pressure should perform a "boost test" to exceed the closure stress of the formation rock as mentioned above in well F-7. It is important that the "boost test" do not exceed the predicted LOT pressure that may open new fractures, but only pre-existing cracks in the Lista and filling them with seawater. The closure stress is given by:

$$P_{max} \text{ Tor (0 psi margin) [psi]} = (2,5333 \text{ x Depth}_{m\,TVD\,MSL}) + 316,67 \qquad (4\text{-}3)$$

which is a correlation with a safety margin of 0 psi. The predicted LOT pressure is given by:

$$P_{max} \text{ Tor (LOT) [psi]} = (3,2068 \text{ x Depth}_{m\,TVD\,MSL}) - 854,46 \qquad (4\text{-}4)$$

which is a correlation with a larger pressure gradient than the other correlations. After the "boost test", the injection pressure is reduced to the initial pressure before the test. During this period, the water that has filled the cracks in the Lista caprock will react with the smectite. As mentioned before, the smectite starts to swell and will increase the closure stress locally. Then it is possible to gradually increase the injection pressure up to a level with a safety margin of 250 psi to the initial closure stress that has been increased. The new injection pressure is then given by:

$$P_{max} \text{ Tor (250 psi margin) [psi]} = (2,5333 \text{ x Depth}_{m\,TVD\,MSL}) + 66,67 \qquad (4\text{-}5)$$

which is the correlation with a 250 psi safety margin. This procedure is illustrated in figure 4.2.2.
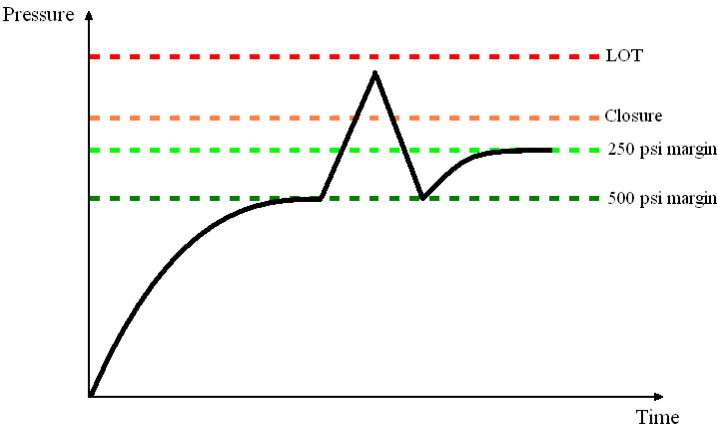
Figure 4.2.2: Proposed injection pressure management procedure for Valhall. As the wells are hitting the maximal initial pressure with 500 psi safety margin below the closure stress, one initiate a boost test and a clay swelling period before reducing margin to 250 psi to allow for minimum risk of out of zone injection. [Kristiansen et al., 2008]

These correlations are estimated from reported LOT data on several wells, and included different safety factors. When plotting these correlations with the initial reservoir pressure and the overburden pressure, it is possible to determine the maximum injection pressure at Valhall, and the plot is showed in figure 4.2.3.
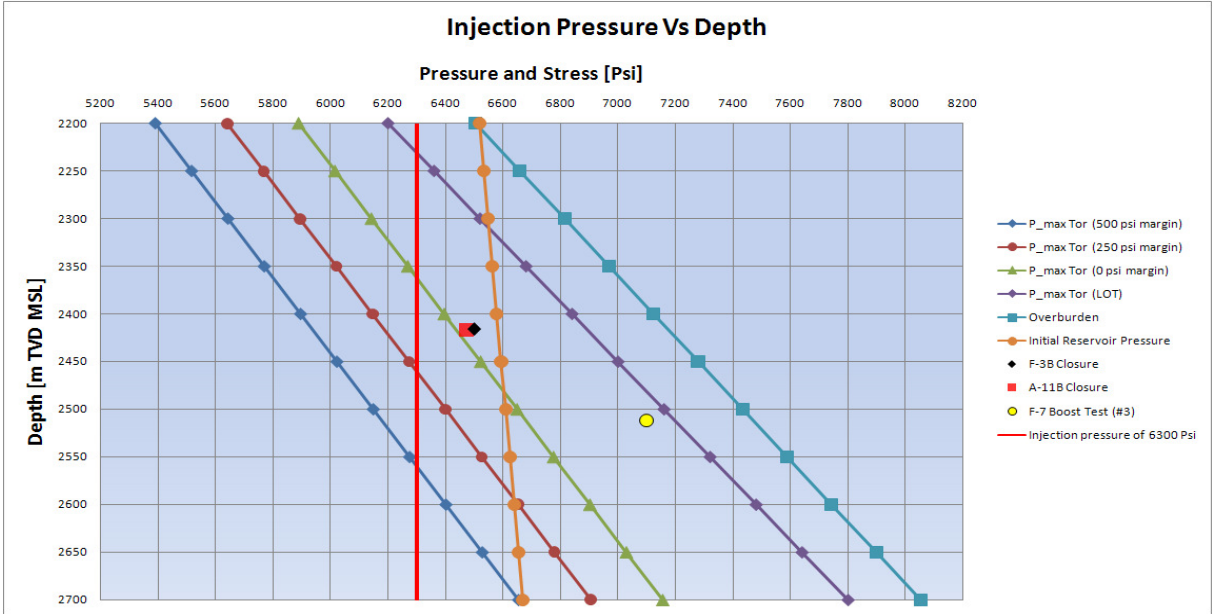
Figure 4.2.3: Plot of the different pressure correlations with the initial reservoir pressure and the overburden pressure. These can be used to determine the injection pressure. The boost test on F-7 and closure pressure on F-3B and A-11B is plotted as well. Note the depths are given by according to MSL. [Kristiansen et al., 2008]

In this plot, closure pressure from well F-3B and A-11B is plot as well, along with a boost test from well F-7. The red line indicates an injection pressure of 6,300 psi which is the wanted injection pressure of all wells on Valhall. By using correlation for a 250 psi safety factor to the injection pressure, it gives approximately an injection pressure of 6,150 psi at ~2,400 m TVD, which is below the requirement. The reason that the injection pressure cannot be increased to 6,300 psi without any safety margin is the large risk of fracturing the formation. Another risk is when drilling new wells and if the well trajectory is too close to an injector injecting out of zone, a water kick into this well could happen.

In order to illustrate the potential economic impact when increasing the injection pressure from a safety margin of 500 psi, to a safety margin of 250 psi on the Valhall IP wells, a reservoir simulation has been performed. This simulation, made by Bjørn Matre, has an injection pressure increase of 300 psi, and the increase of injection rate is conservative as injectivity is kept constant in the model. The result of this simulation indicates a large increase of recovery of 4.5 million barrels of oil equivalent by year 2026. The result is showed in figure 4.2.4.
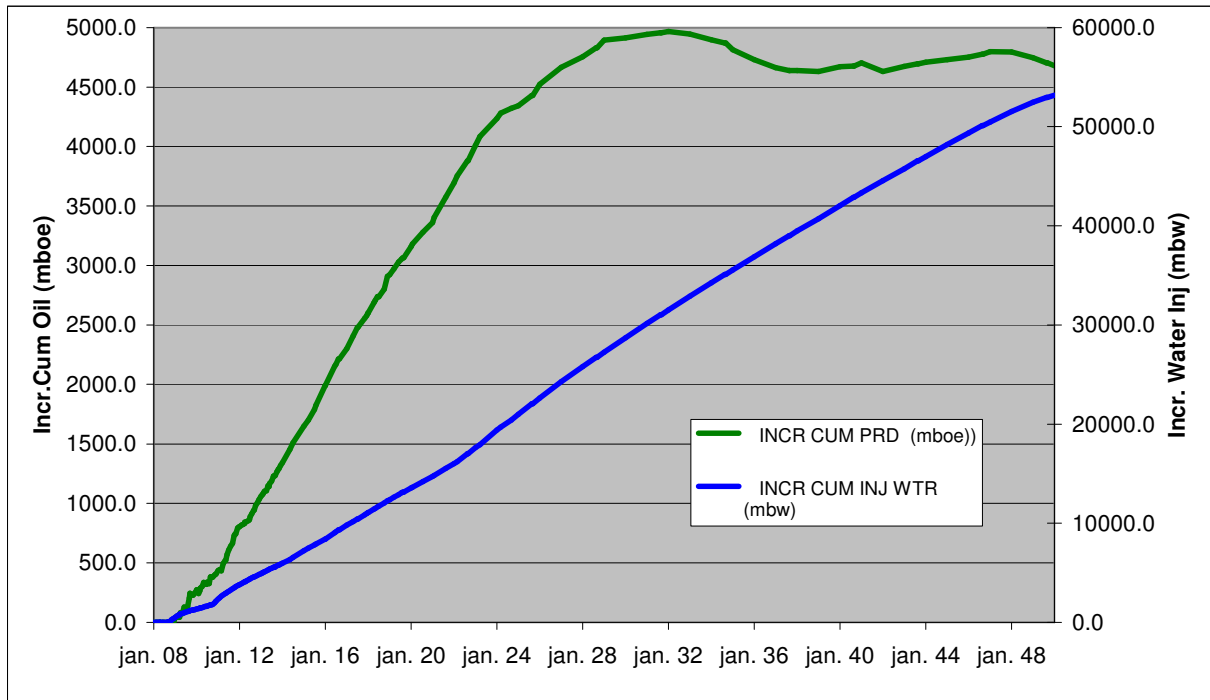
Figure 4.2.4: Results indicating an increase of 4.5 billion barrels of oil equivalent (boe) in 2026 when increasing the injection pressure. The simulation is done by Bjørn Matre. [Kristiansen et al., 2008]

By optimizing the waterflood economics in the design one will improve the well integrity as well, and it could also improve the abandonment.

One of the possibilities to be able to increase the injection pressure to at least 6,300 psi, would be to lower the setting point of the $13^3/_8$" casing. This is not that easy because there are several issues that would make it difficult. One thing is the rig storage capacity, because there is only room for a certain amount of $13^3/_8$" casing joints. Another thing could be the load capacity of the rig, which only could handle a certain length of casing.

The best way of increasing injection pressure while still using a safety of 250 psi, is to create a deeper barrier towards Tor formation than is currently present.

The true vertical depth to the Tor formation varies quite a lot. At the crest of the reservoir, the depth could vary from 2,400 to 2,450 meter TVD, while at the flank of the reservoir it could vary from 2,450 meter TVD and downwards. This means that the crest could handle less injection pressure than at the flanks.

The maximum injection pressure with today's design is as mentioned limited by the $13^3/_8$" casing shoe, and this setting depth varies a lot. The most common setting depth on today's well is between 1,900-2,200 meter TVD for the $13^3/_8$" casing shoe, and the maximum injection pressure is given by, [Kristiansen, 2009]:

$$P_{max}\ (0\ psi\ safety\ factor)\,[psi] = 0,95 * (3,0208\ x\ Depth_{m\,TVD\,MSL}) - 412,63 \qquad (4\text{-}6)$$

at the casing shoe. The maximum injection pressure at any point below the shoe is given by the maximum injection pressure at the shoe added by the hydrostatic seawater pressure from the shoe

to the given depth. In figure 4.2.5 there is a plot showing the comparison between the maximum injection pressure when the barrier is at different $13^3/_8$" casing shoe depths in Eocene, and if the barrier would be located further down in the well. The thick blue line show the maximum injection pressure at $13^3/_8$" casing shoe, and the four thinner lines show the additional hydrostatic seawater pressure to every $13^3/_8$" casing shoe depths. The thick brown line show the maximum injection pressure with a 250 psi safety factor, given by equation (4-5), if there is a barrier at given depth deeper in Paleocene. The red thick line shows the recommended injection pressure at Valhall, which is 6,300 psi.
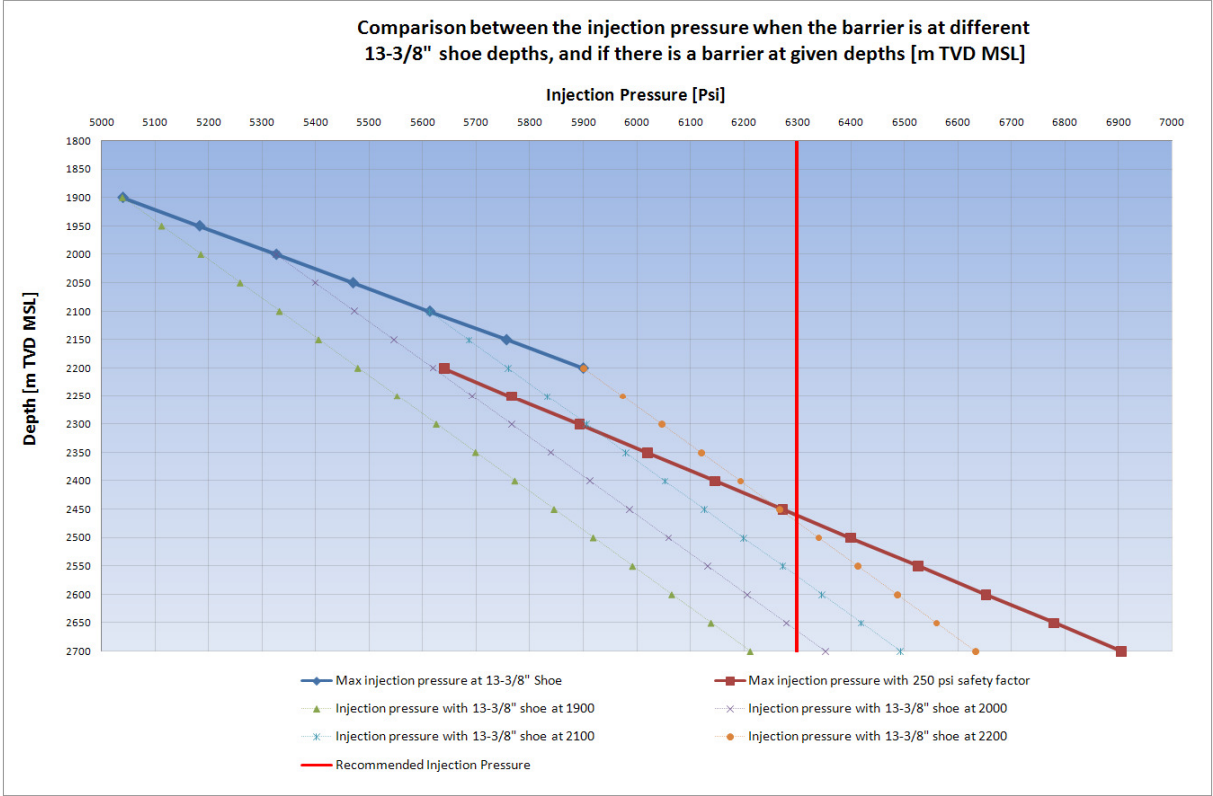
Figure 4.2.5: A comparison between the injection pressure when the barrier is at different $13^3/_8$" casing shoe depths, and if there is a barrier at given depths. Note the depths are given relative to MSL.

To provide a better understanding of the plot in figure 4.2.5, an example where the $13^3/_8$" casing shoe is set at 2,100 meter TVD is showed figure 4.2.6. The blue line is the maximum injection pressure when the barrier is at the $13^3/_8$" casing shoe and the additionally hydrostatic seawater pressure. The brown line show the maximum injection pressure with a 250 psi safety factor if there is a barrier at given depth, and the red line show the recommended injection pressure of 6,300 psi. If there could be a barrier for an example at 2,500 meter TVD, it would be possible to increase the injection pressure from 6,200 psi to 6,400 psi, which is higher than the recommended injection pressure.
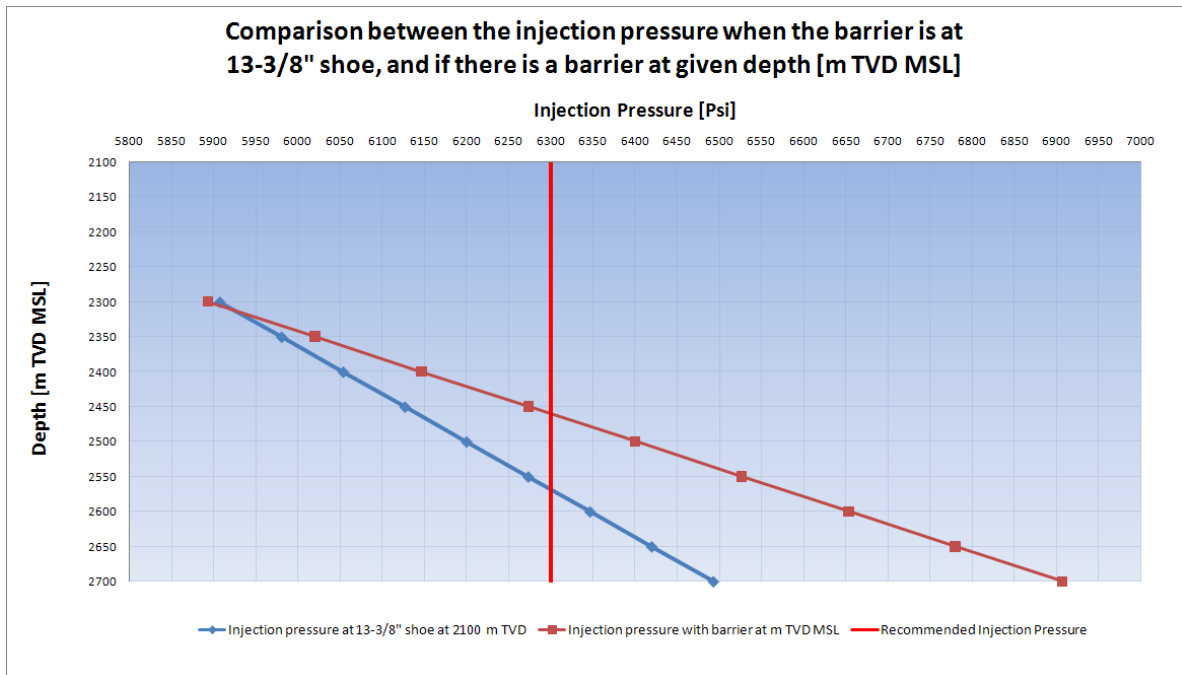
Figure 4.2.6: An example where the $13^3/_8$" casing shoe is set at 2100 meter TVD, and then compared with if there is a barrier at given depths. Note the depths are given relative to MSL.

As mentioned before, at the crest the top Tor formation could vary from 2,400 to 2,450 meter TVD, perhaps more, which means that is not possible to increase the injection pressure as high as 6,300 psi according to figure 4.2.6. If possible, the $13^3/_8$" casing must be set much closer to the Tor formation, which is very difficult and most likely impossible.

To illustrate how much the injection pressure can be increased in the different depths of $13^3/_8$" casing shoe, compared to the injection pressure if there is a barrier at different depths, is showed in figure 4.2.7. Each line shows the different at each setting depth to the $13^3/_8$" casing shoe.
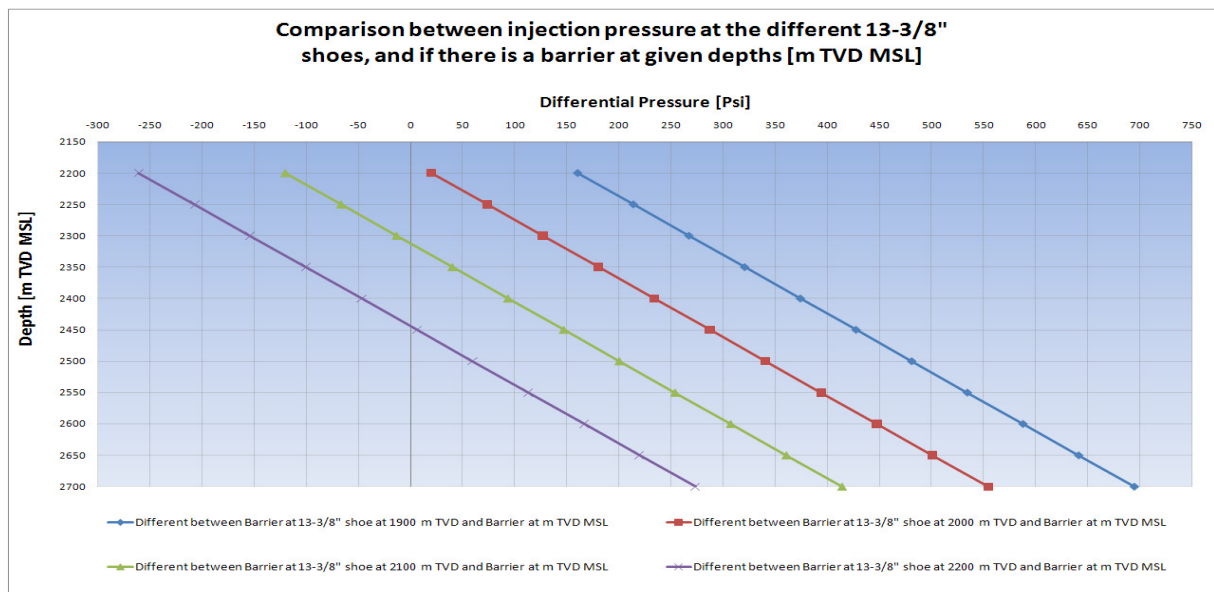
Figure 4.2.7: Comparison between injection pressure at the different $13^3/_8$" shoes and deeper barrier. Note the depths are given relative to MSL.

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Figure 4.2.7 shows that if the $13^3/_8$" casing shoe is at 2,100 meter TVD, then it would possible to increase the injection pressure approximately 200 psi if there is a barrier at 2,500 meter TVD compared to if the barrier was at the $13^3/_8$" casing shoe. Note it does not make any difference where the $13^3/_8$" shoe is if there is a barrier below the shoe.

In any case, by getting a good barrier as far down close to the Tor formation as possible would increase the injection pressure and would be a large benefit economically in the long term. To be able to provide a good barrier, several new options to the present casing design has to be evaluated.

4.3 Potential New Options to Valhall's Casing Design

There are several combinations of the options that could be a potential solution to solve the integrity challenge at Valhall IP. The most straight forward option would be to set an extra casing string a couple of meters above the Tor formation as the original design, but due to large losses and risk of cavings, this option would not be recommended. The best solution at Valhall is to use the drilling liner compared to drilling conventionally, and several new options combined with the drilling liner has been evaluated. These options are;

- Drilling liner combined with Expandable Liner
- Drilling liner combined with Expandable Liner Hanger
- Drilling liner combined with Swellpacker
- Drilling liner combined with Cement Assurance Tool and C-Flex
- Drilling liner combined with C-Flex and Foundation
- Drilling liner combined with Shale Annular Barrier
- Drilling liner combined with Shale Annular Barrier and C-Flex
- Drilling liner combined with Shale Annular Barrier, Cement Assurance Tool and C-Flex
- Drilling liner combined with ThermaSet and C-Flex
- Drilling liner combined with DuraWAV
- Drilling liner combined with ESIPC
- Drilling liner combined with ESIPC and C-Flex
- Drilling liner combined with ESIPC, Cement Assurance Tool and C-Flex

4.3.1 Drilling Liner Combined with Expandable Liner

At present day this combination has not been tested, but Enventure has seen the value of this technology and are looking to develop this system. However, it would not be available until 2010.

So far Enventure has field tested a 8" open-hole clad system to pass through $9^5/_8$" base casing, which once expanded will provide an 8.5" pass through diameter, as showed in figure 4.3.1.1.
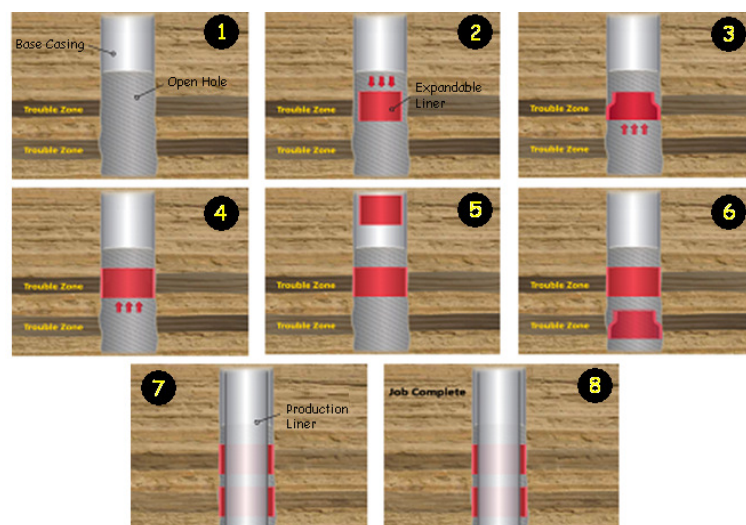
Figure 4.3.1.1: Test Enventure has done based on an open-hole clad system. [Enventure, 2009 b]

Before combining drilling liner and expandable liner, some field test has to be performed. The first phase would be to expand the liner against the formation, facilitating the continuation of multiple "clads" with a uniform ID. The next phase would be to provide a shoe extension of the previous casing without loss of diameter. When these phases have been proven in the field, Enventure will try to develop the concept of the expandable drilling liner.

One idea to combine the drilling liner and the expandable liner would be to use a top-down mechanical expansion, as illustrated in figure 4.3.1.2.
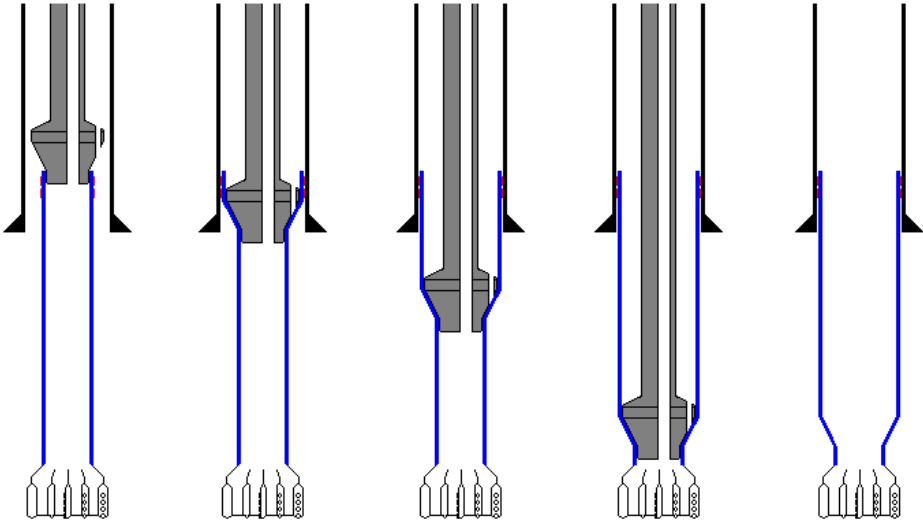
Figure 4.3.1.2: An idea to combine the drilling liner with the expandable liner. The expansion cone is connected to the top of the drilling liner. When the drilling stops, the cone could disconnect from the liner and then start the expansion of the liner.

In practice, this top-down expansion would be difficult. First of all, the force applied downwards is limited and the cone must have sufficient OD to be able to expand the liner against the previous casing. Because of this OD, it would be a too small clearance between the cone and the previous casing to be able to circulate the amount of mud required during drilling. A solution to that would be to make circulation holes in the expansion cone, as illustrated in figure 4.3.1.3.
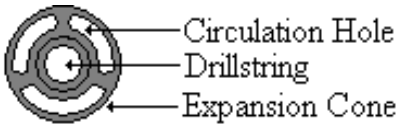
Figure 4.3.1.3: Show the circulation holes in the expansion cone, seen from above.

Another thing that would be difficult with this idea is how the cone is attached to the liner, and then how it can be able to expand the liner. If it is threaded, there would be difficulties for the cone to expand the liner because of the large friction force applied from the threads. The cone has to have a smooth surface to be able to expand. When using drilling liner, the liner is exposed to external wear in form of scratches or gouges to the outer surface. These would be stress-concentrations and possible tensile failure points during expansion. The expandable threaded connections are relatively weak and do most likely not support much drilling torque. Normal drilling liners has usually very strong high-torque threaded connections.

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A third thing that makes it difficult, is that at the bottom of the liner, there is placed a one-way float, a ballseat, and maybe a C-Flex port collar if a cement squeeze job is planned. The liner cannot be expanded in this area, and since the drilling liner often get stuck only a few meters inside the Tor formation, these unexpandable parts would most likely be placed above the Tor formation, as illustrated in figure 4.3.1.4.
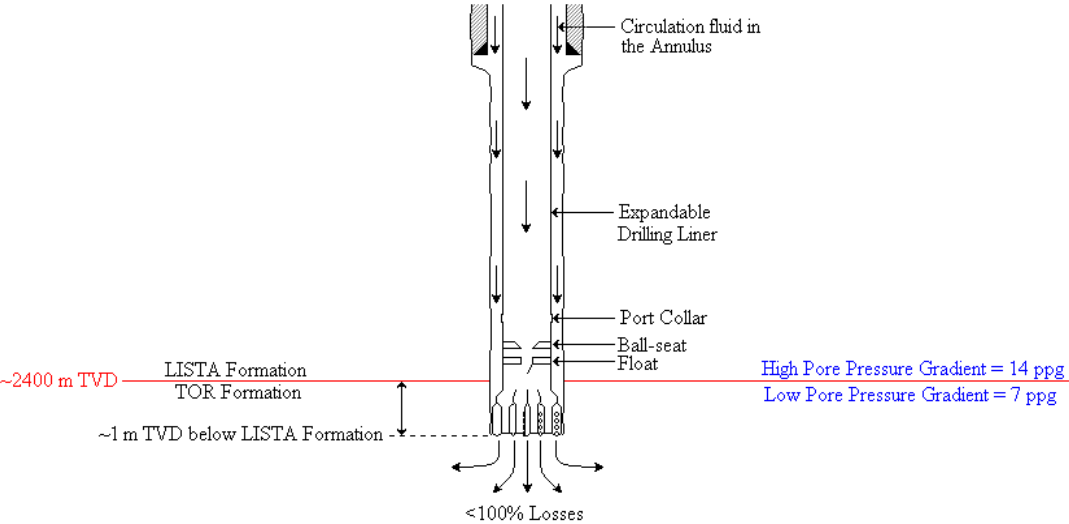
Figure 4.3.1.4: The placement of the one-way float, the ballseat and the C-Flex port collar inside the drilling liner compared with the Tor formation.

Since it is impossible to expand the liner further down than the placement of the C-Flex port collar, the next section bit has to drill out the lower part of the liner. This would result in bottom of the liner set above the Tor formation, which do not solve anything, and a cement squeeze job through C-Flex is still required.

Another method that could be used is to set the $9^5/_8$" Liner 5-10 meters TVD above the Tor formation, and then use a $7^5/_8$" Expandable drilling liner to drill the last meters into the Tor formation, as illustrated in figure 4.3.1.5.
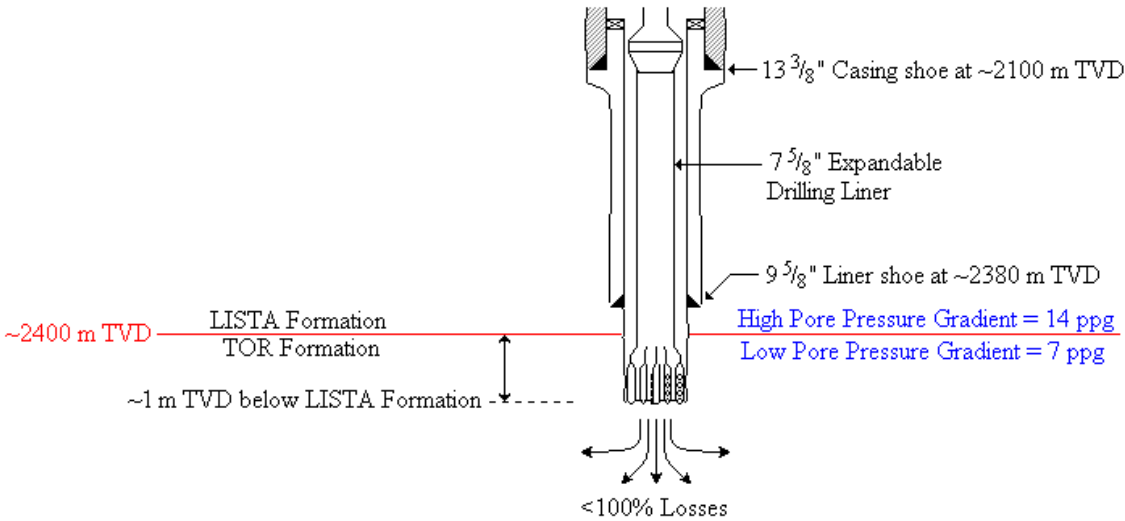
Figure 4.3.1.5: Illustrate if setting the $9^5/_8$" Liner 5-10 meters TVD above the Tor formation and drill further with the $7^5/_8$" Expandable drilling liner.

The negative with this design would be the same as using the $9^5/_8$" Expandable drilling liner, the drilling liner does not get far into the Tor formation and will get stuck at the end, and would most likely not able to expand the liner inside the Tor formation.

The last method is using monodiameter drilling liner. This would be complex as well, because it would have the same problems as mentioned above due to expand the liner the same moment the drilling stops.

Overall, expandable liner combined with drilling liner is a very complex option, and it could be difficult to develop. It may be a possibility if the C-Flex port collar could manage to be expanded, or even removed, and, somehow, manage to force the drilling liner a little further down into the Tor formation, which is most likely impossible.

4.3.2 Drilling Liner Combined with Expandable Liner Hanger

As mentioned, this method has been tried out by Halliburton at the Green Canyon Block 158 in the Gulf of Mexico [Mota et al., 2006], and the result was successful. The expandable liner hanger was strong enough to be used along with the drilling liner to address difficult borehole condition where it is required to drill or ream to the bottom. When combining expandable liner hanger with drilling liner provides a benefit of a one-trip process for the drilling part, hanging the liner and setting the hanger packer, which save time and cost. But the liner hanger system that is used on Valhall today has these benefits as well, and provides a seal between the previous casing and the drilling liner. However, the hanger packer is not being considered as a barrier element because it is exposed to wear from both rotation and circulation containing cuts, which reduces the quality of the packer element.

This option could provide a simplified sealing of the liner to the previous casing.

4.3.3 Drilling Liner Combined with Swellpacker

Both oil swelling and water swelling packer has been proven to be a good zonal isolation material in the trouble formations and in the reservoir. These packers could be included on a drilling liner, because the rubber is very hard-wearing and has a low running friction. Additionally, it is self healing which mean any damages that could happen during drilling would be repaired when the packer swells.

A disadvantage with the Swellpackers is that they use too much time to swell if a quick zonal isolation is needed when large losses occur. It is possible to delay the swelling process, but it is not easy to know how long time it should be delayed during drilling, because it is uncertain when the drilling liner is getting stuck and the circulation losses is up to 100%. It is at this time the Swellpacker is needed, to stop the losses and seal the well. But if the well is being sealed conventionally with the ball and the hanger packer, it would make a proper seal after some days which are positive regarding integrity.

Another thing, to be able to swell to $12^1/_4$", the OD of the Swellpacker has to be least $11^1/_2$", which gives a clearance between the packer and the wellbore of $^1/_2$", which is not much compared to the

amount of mud passes through the packer during drilling. It is not impossible, but has to be taken into account.

The location of the Swellpacker should be as illustrated in figure 4.3.3.1, and should be an oil swelling packer since the swelling fluid would be oil based mud.
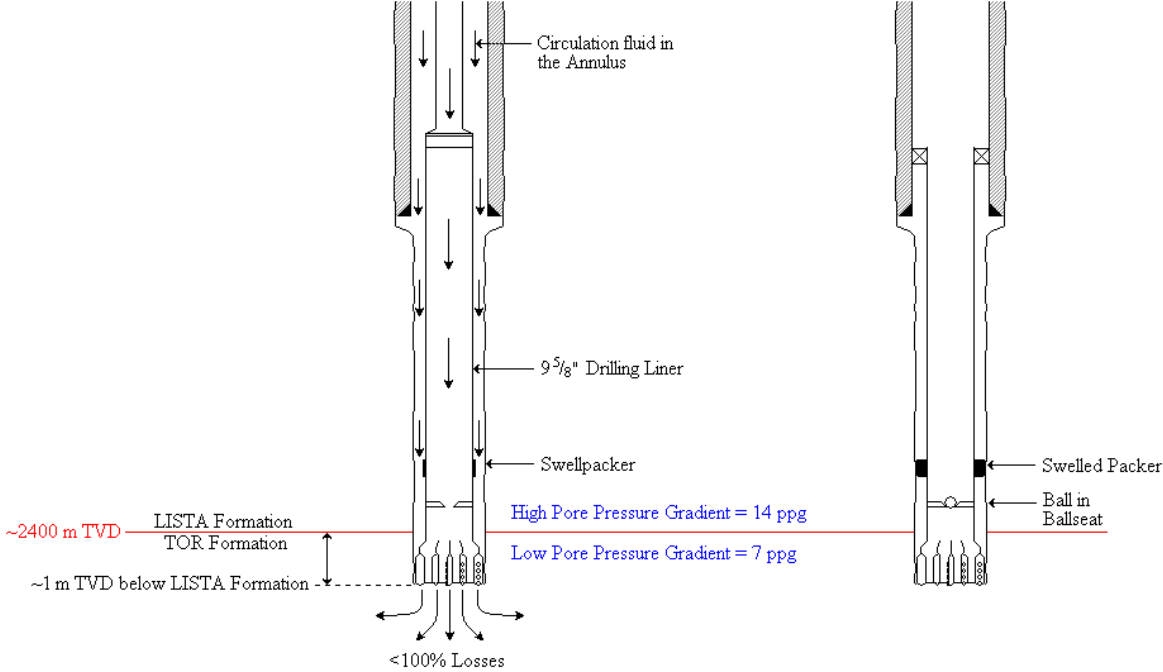
Figure 4.3.3.1: Show the location of the Swellpacker.

The Swellpacker could be a solution on Valhall. Since it is not a qualified barrier element according to NORSOK, it would be recommended to be combined with other methods. It is still necessary to seal the well with the dropped ball and setting the hanger packer. The Swellpacker is a good method to seal in long term, but is not able to seal the well instantaneously when the liner is getting stuck to stop the circulation losses.

4.3.4 Drilling Liner Combined with Swellpacker and C-Flex

By combining drilling liner with both Swellpacker and C-Flex, it is possible to do a cement squeeze job through the C-Flex after the Swellpacker has swelled, as illustrated in figure 4.3.4.1. In this way, there would not be a connection between the well and the reservoir, which will force the cement upwards and make a good cement job. The Swellpacker should be placed below the C-Flex, and should be an oil swelling packer since the swelling fluid would be oil based mud.

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Circulation fluid in the Annulus

9 $\frac{5}{8}$" Drilling Liner

Cement

Port Collar

Swellpacker

Swelled Packer

~2400 m TVD — LISTA Formation
TOR Formation

Ball in Ballseat

High Pore Pressure Gradient = 14 ppg

Low Pore Pressure Gradient = 7 ppg

~1 m TVD below LISTA Formation

<100% Losses
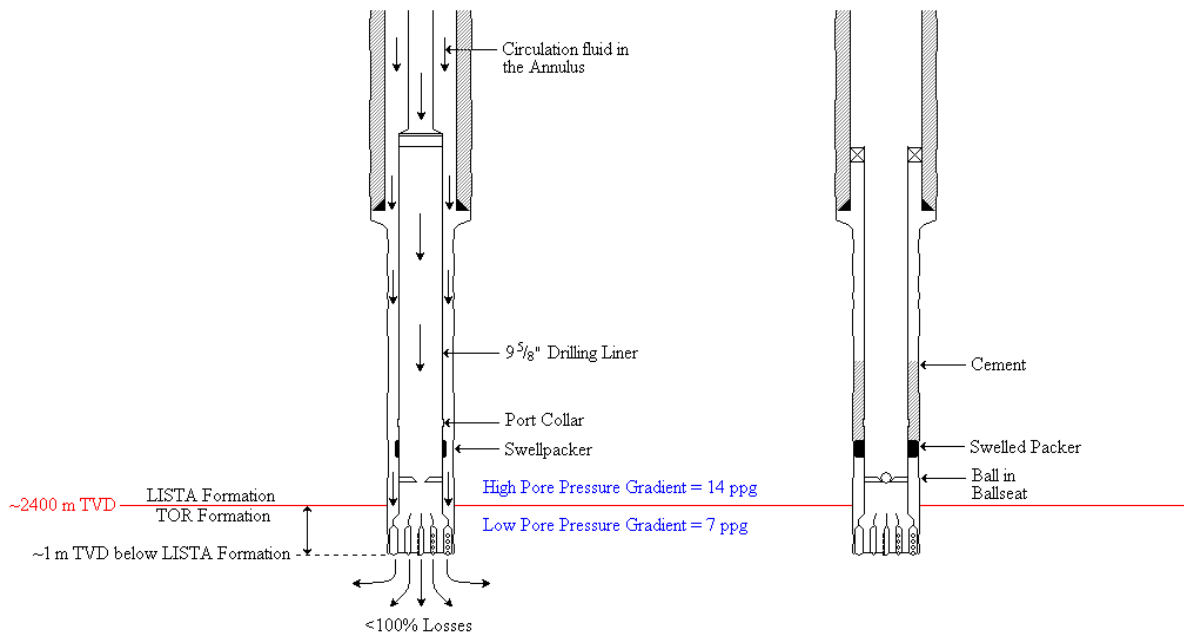
Figure 4.3.4.1: The location of the Swellpacker compared with the C-Flex port collar, and how the Swellpacker will force the cement upwards.

The Swellpacker and the C-Flex could be a good solution on Valhall, but it would still be necessary to seal the well with the dropped ball and setting the hanger packer, and additionally run cement bond log to verify the quality of the cement squeeze job.

4.3.5 Drilling Liner Combined with Cement Assurance Tool and C-Flex

By combining drilling liner, Cement Assurance Tool and the C-Flex port collar, the probability of having a better seal is larger than with C-Flex alone. By cementing through the C-Flex conventionally it will, hopefully, provide a seal around the liner. If there is a leak, for an example through a micro-annulus, the swell packer would swell and stop the leak. In this combination with C-Flex, the Cement Assurance Tool would be the best alternative of the different types of Swellpackers. This packer will not stop the cement flowing upwards or downwards, like probably the ordinary Swellpackers would do, but it will seal the micro-annulus after the cement is set if there occurs a leak. One has to assume that if the liner is into the Tor formation, the cement will go down towards low pressure. The assurance tool could be placed both below and above the C-Flex, as illustrated in figure 4.3.5.1. With this placement, the Cement Assurance Tool could seal the micro-annulus if the cement goes downwards or upwards, depending on if there is connection between the well and the reservoir. The Cement Assurance Tool should be a dual system with both oil- and water swelling packer since the swelling fluid could be reservoir fluid or injection water that migrates through micro-annulus.
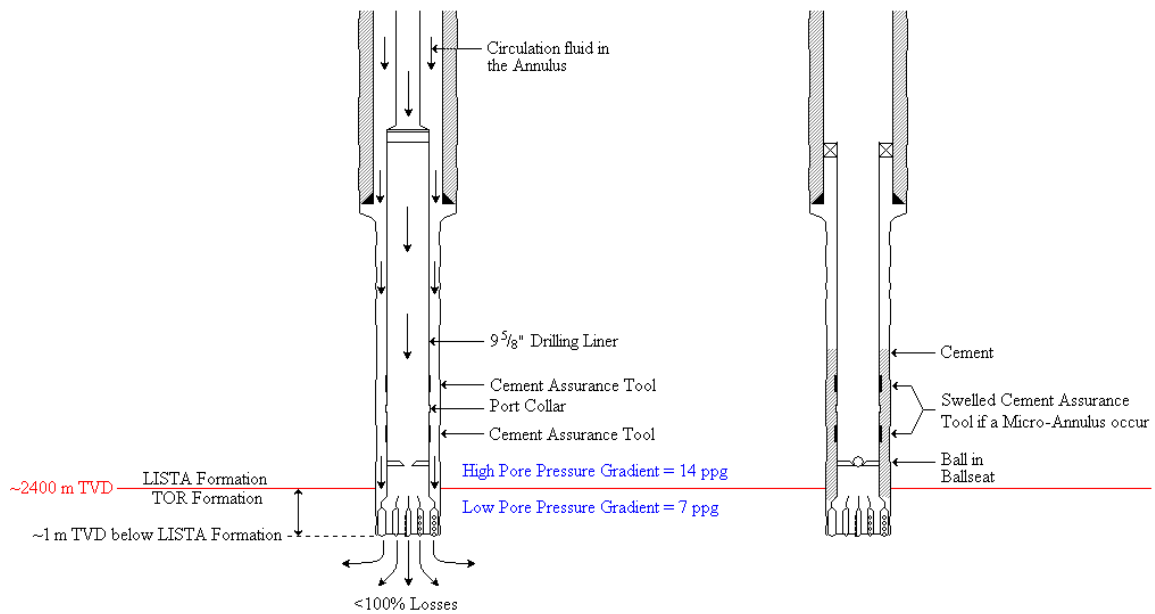
Figure 4.3.5.1: The location of the Cement Assurance Tool, both below and above the C-Flex port collar.

This would be a good solution on Valhall, but will be dependent on the quality of the cement job, and will not be verified as an approved barrier without any logging or pressure tests.

4.3.6 Drilling Liner Combined with C-Flex and Foundation

The idea of using the C-Flex with foundation combined with the drilling liner could be a good solution to Valhall's challenges. As mentioned before, the foundation provides a better control of the cement squeeze job through the C-Flex port collar. The way to include the foundation with the drilling liner is illustrated in figure 4.3.6.1.
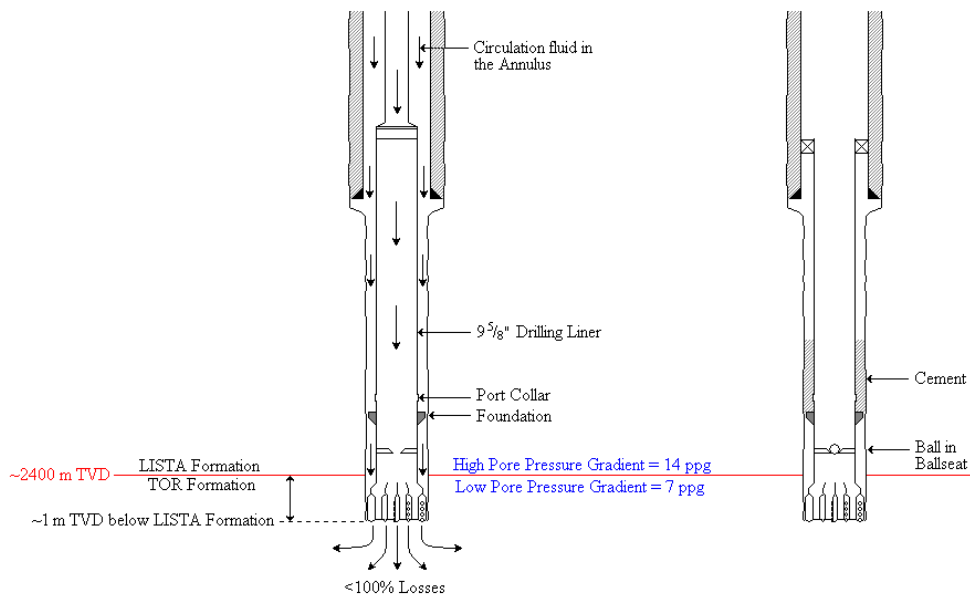
Figure 4.3.6.1: Show the possibility to include the foundation with the drilling liner.

The challenge with this foundation would mainly be the circulation requirement during drilling. Because of the large OD of the foundation, the clearance to the wellbore would be quite small, and the foundation must have as large OD as possible to work properly. Circulation could be achieved through the one-way valves if they were upgraded, but it would still be a challenge.

Another thing, if the well is not able to be drilled as planned, a contingency plan must be available. If a contingency is needed between the $13^3/_8$" casing and the $9^5/_8$" liner, it would be a $11^3/_4$" liner. The ID of this liner is depending on what steel grade that is required, if it is a $11^3/_4$" with Q-125 steel quality and a weight of 65 ppf, the drift ID would be 10.625" [VAM, 2009], which is the smallest ID in the pipe. The OD of the foundation must then be less than 10.625", which gives a clearance to the wellbore at the $12^1/_4$" under-reamed section of at least 0.8125". The OD of the foundation is too small to work as it should, and there is not any point including it.

Since the foundation is made of aluminium, it would be less wear resistance compared to steel types, and because of its larger OD compared to the liner it would be more exposed to surface wear than the liner during drilling. In worst case, the foundation could be worn-out before the liner is set, and is then useless. The foundation could be reinforced with a stronger steel type, but this would perhaps make other difficulties as extra required torque, extra weight among others.

Another issue is if there is a communication between the well and the reservoir, the foundation would probably not stop the cement from squeezing into the reservoir instead of being force upwards.

4.3.7 Drilling Liner Combined with Shale Annular Barrier

As mentioned before, use of shale as a natural annular barrier has been verified as a non-destructively high quality annulus barrier in many wells, [Williams et al., 2009]. The most likely reason that the drilling liner is getting stuck on Valhall at present day is because of the collapsing Lista formation or differential sticking in the reservoir. If collapsing Lista is the case, the Lista shale may provide a qualified annular barrier at the top of the Tor formation.

To verify that the Lista shale has collapsed and provides an approved barrier according to NORSOK, additional logging has to be performed, and the formation has to be pressure tested to determine if the barrier on the logs is real. Pressure testing and additional logging is quite expensive, and has to be done during a break in the drilling operation at the rig if they should be performed. To be able to pressure test the shale, the $9^5/_8$" liner has to be perforated, which could be a large risk and additionally a sealing solution inside liner is needed. This sealing solution could be an expandable liner, a packer or by using a cased-hole dynamics tester (CHDT), either way it would demand an extra trip into the well.

The disadvantage with the shale annular barrier is that it is impossible to affect the quality of the barrier, or even affect the collapse itself, it could happen either if it is wanted or not. If the logs show a bad annular sealing, the additional cost of the logging would be lost. If the logs had showed a good annular sealing, it would be worth the additional cost. The result from the logs is an uncertainty, and

the use of logging should be compared with how valuable the results are if they show a good or a bad annular seal.

Another thing, the sealing state could be a function of time, meaning that the shale would not seal properly before a certain time that could be days, weeks or even years. The sealing state is depending on the shale properties. If extra logging and pressure testing is performed during drilling, and the shale has not collapsed yet, it would be worthless, and a hole in the liner which has to be plugged. To verify that the shale has provided a good barrier, the logging and pressure testing has to be done after some years, which means that the completion string has to be pulled out. There would be an extra challenge in cases where the reservoir liner is cemented in place above the $9^5/_8$" drilling liner, which means that the pressure test must be performed through two sets of liner and the cement between them, as showed in figure 4.3.7.1. This would be very expensive, and there is still no guarantee that the shale has provided a barrier.
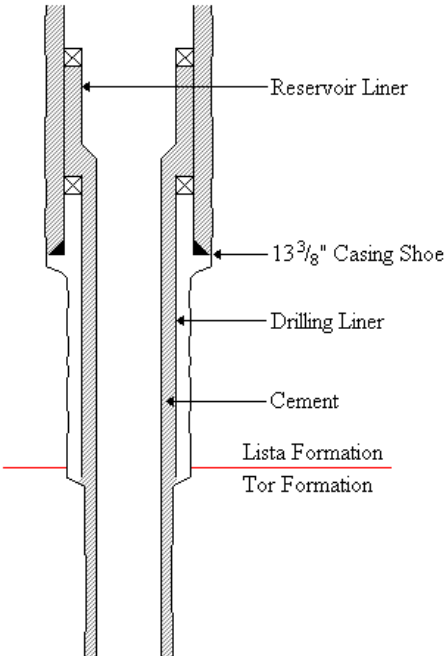
Figure 4.3.7.1: Illustrate how the reservoir liner is cemented in place.

Shale annular barrier could definitely be a solution on Valhall, and it is likely already there because of the stuck drilling liner, it is just not verified yet. But this method would result in expensive logging and pressure testing which would not necessarily give the wanted result, and an additional plan would be required in case of bad sealing.

BP is planning to do logging and pressure tests when they plug and abandon the old DP wells. These wells are the oldest on Valhall and should give an indication of how the shale has collapsed. The seal method planned to use is a CHDT from Schlumberger. The CHDT drill a small hole in the casing and into the formation, perform multiple pressure measurements and then plug the hole made in the casing. This plug tolerates a differential pressure of 10,000 psi, [Schlumberger, 2009].

4.3.8 Drilling Liner Combined with Shale Annular Barrier and C-Flex

By combining the shale annular barrier with the C-Flex port collar and which is most likely done today at Valhall without knowing for sure the state of the collapsed shale, may provide a proper seal in the annulus. As mentioned before, a squeezed job through the C-Flex could be a good cement job, but it could be a bad cement job as well, which is depending on the shale.

This probably is a solution at Valhall, and by running additional logging and pressure testing, it is possible to verify if the shale has collapsed around the liner, and that the cement has been set where it should be. But the pressure testing and logging is very expensive.

4.3.9 Drilling Liner Combined with Shale Annular Barrier, Cement Assurance Tool and C-Flex

By combining Swellpacker with the shale annular barrier and the C-Flex with the drilling liner, it would provide a better seal than without the Swellpacker. The Swellpacker would, as mentioned before, seal the micro-annulus if a leak occurs. An ordinary cement job is squeezed through the C-Flex, and the Swellpacker would be attached to the drilling liner above the C-Flex. As mentioned earlier, in the cases with combination with the C-Flex, the Cement Assurance Tool is recommended compared to ordinary Swellpackers.

This could definitively be a good solution to Valhall's problem, by running Cement Assurance Tool additional to the ordinary method, which gives an extra assurance for providing a required barrier, but the pressure testing and logging is very expensive.

4.3.10 Drilling Liner Combined with ThermaSet and C-Flex

As already mentioned, ThermaSet is very strong compared to the cement, and has a possibility to be squeezed through the C-Flex as well as the cement. The ThermaSet could be customized, which is a large benefit. By making the ThermaSet with a high viscosity, it could be possible to seal off the area around the drilling liner better than cement. The cement has an ability to migrate everywhere, in different fractures, because it is not that viscous. The amount of ThermaSet to seal off the annulus is then not that large as the amount of cement. By using ThermaSet, the well would have a larger resistance against the shear stresses in the formation.

The negative with the ThermaSet is mainly the cost. It is very expensive compared to cement, and in a squeeze job through the C-Flex port collar often requires a large amount of fluid, which would be many times more expensive than cement. The large amount of squeeze fluid is required to hopefully get a good seal, and it is recommended to use as much ThermaSet as cement to be certain. If the squeezed fluid disappears from where is should be set, it is better that the lost sealing material is cement and not ThermaSet because of the cost.

Use of ThermaSet could be a solution on Valhall, but it is, as mentioned, much more expensive than cement, and there is no guarantee that it would seal of the annulus any better than the conventional cement.

4.3.11 Drilling Liner Combined with DuraWAV

Combining DuraWAV with the drilling liner is most likely impossible, and would not be any solution to the barrier challenge at Valhall anyway. First of all, because of the high torque and the large weight on bit, the DuraWAV would not be able to withstand the forces applied during drilling. It would most likely compact and bend, and make it difficult to continue the drilling process. Also, the DuraWAV will not do any better job than an ordinary drilling liner, because it must still be cemented or sealed by the shale. However, the DuraWAV could be included in the production liner where the trouble interval of the formation is located. It withstands the compaction- and shear stresses better than conventional liners, as illustrated if figure 4.3.11.1, which provides a larger operation time of the well.

Without DuraWAV   With DuraWAV
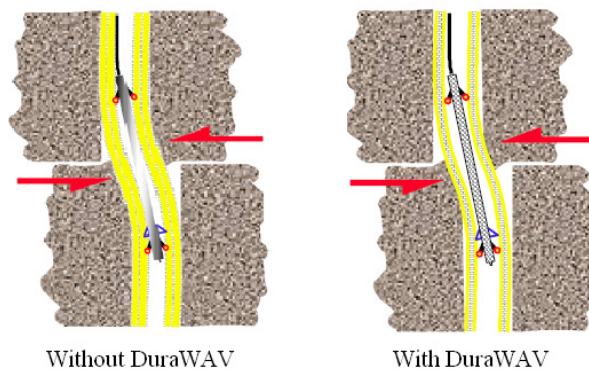
Figure 4.3.11.1: Illustrate how the DuraWAV can withstand shear stresses better than conventional liners. [DuraWAV, 2009]

DuraWAV could be a solution to the compaction challenge at Valhall, as showed in figure 4.3.11.2, but would probably not solve the integrity challenge above the Tor formation.

Without DuraWAV   With DuraWAV
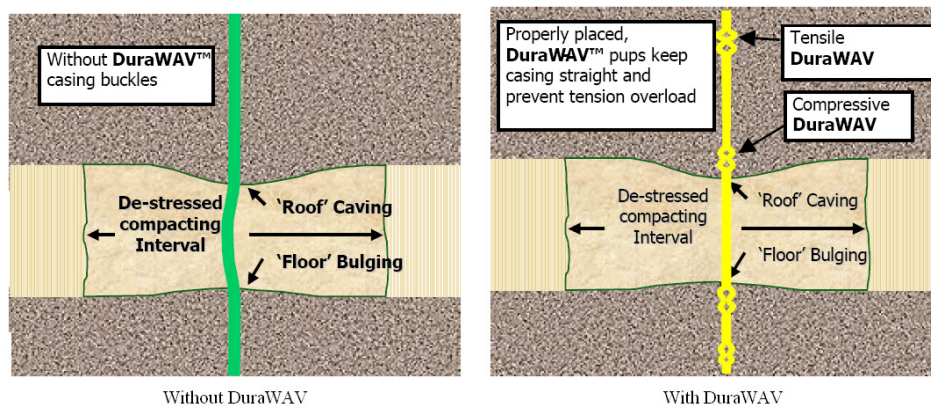
Figure 4.3.11.2: The DuraWAV can withstand the compaction of the formation better than conventional liners or casings. [DuraWAV, 2009]

4.3.12 Drilling Liner Combined with External Sleeve Inflatable Packer Collar (ESIPC)

By combining the ESIPC with the drilling liner could be a solution to get a barrier from the location of the ESIPC and upwards. One of the benefits with the ESIPC is the ability to pump the cement into the

annulus, with returns at surface giving an indication that the annulus at the drilling liner is filled with cement. This would meet the NORSOK requirements. If the barrier could be verified, then the injection pressure of the water could be increased further and therefore increase oil production in the long term.

4.3.13 Drilling Liner Combined with ESIPC and C-Flex

By including the C-Flex port collar to the drilling liner additionally to the ESIPC, the ordinary cement squeeze job could be performed in addition to the cement job through the ESIPC. This could give an extra insurance to seal the annulus at the bottom of the drilling liner, but there would still be a barrier from the location of the ESIPC and upwards if the squeeze job fails.

4.3.14 Drilling Liner Combined with ESIPC, Cement Assurance Tool and C-Flex

By including the Cement Assurance Tool additionally to the C-Flex, ESIPC and the drilling liner, it will provide an extra insurance if a leak should occur after a certain time. This could be a good solution to the barrier challenge at Valhall.

The negative with the ESIPC, is that at present time, it is not strong enough to be included on the drilling liner, mainly because of the high torque. The torque the ESIPC must handle is limited by the running tool at the top of the $9^5/_8$" drilling liner, which has a minimum makeup torque between 28,000-34,000 ft.Ibs., [Baker Oil Tools, 2009]. Another issue is how large collapse- and burst loads the ESIPC could handle, especially after it has been set. It should not be a much weaker point than the rest of the liner.

At present time, the differential pressure above the packer is approximately 4,000 psi [Halliburton, 2009 b], and this value is questionable if the packer element should be expanded in a $12^1/_4$" wellbore.

The plug seat in the ESIPC must handle a large pressure differential, especially at the moment the plug is being set because this would provide a large pressure shock against the seat that could cause damage to the ESIPC. Another thing, this plug seat must handle a large amount of circulation fluid during drilling, which is perhaps 6 barrels per minute for approximately 8 hours, the time it take from the start of drilling with the liner until the plug is set.

If the ESIPC could be set with mud instead of cement, it would make the ability to check the quality of the well and measure the amount of the returns before cementing the drilling liner. Fully returns are an indication that the well has no fracture where the cement could migrate and disappear, and there would be a larger chance for a successful cement job.

These are some issues that have to be considered if the reinforcement of the ESIPC should be performed. Reinforcing the ESIPC would result in redesign and testing, and it would involve a certain amount of cost. If the modified ESIPC could be a solution on Valhall, resulting in an increased injection pressure on future wells, the cost of the ESIPC would be insignificant in comparison. The ESIPC would also give a proven barrier at top reservoir.

5 Discussion

The following sections are ranking, comparing and evaluating the different identified options. This part also shows how to include the recommended option in the current casing design and what further work needed to make it possible.

5.1 Ranking the Different New Options

There are a lot of advantages and disadvantages for every option to the present casing design at Valhall. To be able to evaluate which option implementation would be the best to include in the present casing design, they has been ranked with numerical values on the different criteria. The criteria are:

- Ability to achieve an injection pressure of 6,300 psi, guaranteed every time.
- The ability to provide a required integrity according to NORSOK, both theoretical effect and the feasibility.
- The ability to be included in case of a contingency.
- How long operation time the implementation could handle.
- Difficulties during installation.
- The cost of the implementation.

A main criterion should be the tolerance against shear displacement in the formation. A cemented liner lap is used to increase this tolerance today. Every option presented there could be combined with a liner lap, and this criterion is therefore not taken into consideration in this ranking exercise.

These criteria have varying importance in terms of how the casing design has to be improved, and will be weighted differently. The weighting used in this ranking is:

1) Injection pressure   = 10
2) Integrity, theoretical effect   = 9
3) Operation lifetime   = 8
4) Contingency   = 7
5) Integrity, feasibility   = 6
6) Installation   = 3
7) Cost   = 2

Since the ability to increase the injection pressure every time is the main issue, it is weighted highest with a value of 10. The theoretical effect on integrity is very important as well. The theoretical effect is how good the barrier would work and maintain the integrity of the well, and is weighted with a value of 9. The next important issue is the operation lifetime, if the option does not last more than a couple of years, then it is not worth using. This criterion is weighted with a value of 8. Contingency is important as well. It is not often a contingency plan is needed, but to be able to guarantee higher injection pressure every time, it must handle contingency as well. This issue is weighted with a value of 7. The feasibility on the integrity has been ranked after today's situation of the technology. This

could be improved by redesigning and is weighted with a value of 6. Less important is the installation issue. Even if it could be difficult to install the technology, does not mean that it is impossible. The installation issue is weighted with a value of 3. The least important of the issues is the cost, because if the technology cost an extra million NOK it would almost be insignificant compared to what a well cost. If the technology work properly and will increase the lifetime of the well, the cost has nothing to say, especially if a workover operation is needed later because it don't work properly. A workover operation is quite expensive.

The ranking values (RV) of the different options used in table 5.1.1 are:

- Not applicable   =0   (Red colour)
- Very Bad   =0 < - < 2   (Red colour)
- Bad   =2 ≤ - < 4   (Red colour)
- Average   =4 ≤ - < 6   (Yellow colour)
- Good   =6 ≤ - < 8   (Green colour)
- Very Good   =8 ≤ - ≤ 10   (Green colour)

Table 5.1.1: Show the ranking of the different options, where every option is combined with a drilling liner. Every option has been given a ranking value (RV), which is multiplied with the weighting value of the given issue. All the ranking values are multiplied with the weighting value together gives the total.

Potential Options combined with drilling liner	Injection Pressure		Integrity T.E.		Operation lifetime		Cont.		Integrity Feasibility		Installation		Cost		TOTAL
	[RV]	[RV] x10	[RV]	[RV] x9	[RV]	[RV] x8	[RV]	[RV] x7	[RV]	[RV] X6	[RV]	[RV] x3	[RV]	[RV] x2	
ESIPC, Cement Assurance Tool and C-Flex	10	100	8	72	10	80	4	28	3	18	5	15	2	4	317
ESIPC and C-Flex	10	100	8	72	9	72	4	28	3	18	5	15	2	4	309
ESIPC	10	100	8	72	8	64	4	28	3	18	6	18	2,5	5	305
Shale Annular Barrier, Cement Assurance Tool and C-Flex	5	50	8	72	8	64	9	63	5	30	4	12	2,5	5	296
Shale Annular Barrier and C-Flex	5	50	8	72	8	64	9	63	4	24	5	15	3	6	294

Option														Total
Cement Assurance Tool and C-Flex	6	60	5	45	5	40	9	63	8	48	5	15	5	10	281
ThermaSet and C-Flex	5	50	5	45	8	64	9	63	5	30	5	15	2,5	5	272
Swellpacker and C-Flex	5	50	6	54	7	56	0	0	5	30	5	15	5,5	11	216
Swellpacker	5	50	5	45	6	48	0	0	5	30	7	21	6,5	13	207
Shale Annular Barrier	2	20	2	18	8	64	9	63	2	12	5	15	3	6	198
C-Flex and Foundation	5	50	3	27	5	40	1	7	5	30	5	15	6	12	181
Expandable Liner Hanger	0	0	1	9	5	40	5	35	8	48	8	24	6	12	168
DuraWAV	0	0	3	27	8	64	5	35	3	18	5	15	3	6	165
Expandable Liner	1	10	1	9	3	24	3	21	3	18	7	21	5	10	113

To get a better understanding why the different options have been given the specific ranking values, the detailed argumentation is given in table A1 in Appendix A.

5.2 Result from Evaluating the Ranking Values

ESIPC, Cement Assurance Tool and C-Flex;

After evaluating the ranking values of the different options, the best one would be to combine the ESIPC, Cement Assurance Tool and the C-Flex with the drilling liner. This option got the highest ranking score, mainly because it can guarantee a higher injection pressure every time, the theoretical effect of the integrity is quite high, and the operation lifetime would be at least as long as the well itself due to a higher injection pressure. Some lower score is given because of the unknown cost and feasibility on the integrity, but it would be a very good solution to provide a good barrier at the top of Tor formation. How well this option could handle a contingency situation is unknown as well because it needs redesigning. The Cement Assurance Tool would provide extra insurance in case if there should be a leak past the packer in the ESIPC, which gives a better operation lifetime. The squeeze job through the C-Flex gives a better operation lifetime but has an extra cost.

ESIPC and C-Flex;

This option came in second. The difference between this option and the first one above is the Cement Assurance Tool. This option could give a less operation lifetime if a leak through a micro-annulus occurs, but still has the C-Flex and an extra cement squeeze job is possible.

ESIPC;

This option came in third. The difference between this option and the second one is the C-Flex port collar. This option gives a lower cost, but could give a less operation lifetime if a leak through a micro-annulus occurs. In addition it has not the ability to do an extra cement squeeze job.

Shale Annular Barrier, Cement Assurance Tool and C-Flex;

This option came in fourth. This option ranked high because of the theoretical effect on integrity, operation lifetime, and the ability to handle a contingency. Some lower score is given because it cannot guarantee a higher injection pressure every time, and the feasibility of the integrity is average because there is no guarantee that the shale provides a proper seal. The Cement Assurance Tool would provide an extra insurance in case a leak should pass the cement. In these cases, the Cement Assurance Tool along with the cement squeeze job through the C-Flex gives a higher feasibility of the integrity. The pressure test and logging would give a large extra cost, and has to be taken into account.

Shale Annular Barrier and C-Flex;

This option came in fifth. The difference between this option and the fourth one is the Cement Assurance Tool, which could in this case give a lower feasibility on the integrity. The pressure test and logging would give a large extra cost, and has to be taken into account.

Cement Assurance Tool and C-Flex;

This option came in sixth. The reason for this rank is because the feasibility of the integrity is quite good along with the ability to handle a contingency. It scored average on its ability to increase the injection pressure and the theoretical effect on the integrity.

ThermaSet and C-Flex;

This option came in seventh. The reason for this rank is because the ThermaSet cannot guarantee a better barrier than cement and increase the injection pressure.

Swellpacker and C-Flex;

This option came in eighth. The reason for this rank is because the Swellpacker cannot guarantee an increased injection pressure, and is not applicable in a contingency situation. The squeeze job through the C-Flex gives in this case an average theoretical effect on the integrity.

Swellpacker;

This option came in ninth. The difference between this option and number eighth is the C-Flex port collar, and gives a lower theoretical effect on the integrity.

Shale Annular Barrier;

This option came in tenth. The reason for this rank is because there are no guarantees that the shale would collapse around the liner, even after some years. When there is nothing to "help" the shale sealing the annulus, there is no guarantee that the injection pressure can be increased. The theoretical effect on the integrity and feasibility is bad as well.

C-Flex and Foundation;

This option came in eleventh. The reason for this rank is because the foundation would not prevent the cement from being squeezed into the reservoir if there is a communication, and can't be used in a contingency situation.

Expandable Liner Hanger;

This option came in twelfth. The reason for this rank is because it offers no direct solution to increasing injection pressure because it is placed at the top of the liner while the barrier challenge is at the bottom of the liner. The theoretical effect on the integrity is therefore very bad. The feasibility, the operation time, installation and the cost were good.

DuraWAV;

This option came in thirteenth. The reason for this rank is because it offers no direct solution to increasing injection pressure.

Expandable Liner;

This option came in last. The reason for this rank is because it cannot be included in a drilling liner in a way that it could increase the injection pressure. The theoretical effect on integrity is very bad.

5.3 How to Include the Recommended Option

The recommended option was to include the ESIPC, Cement Assurance Tool and the C-Flex on the drilling liner. This may be achieved by running the C-Flex in its usual position in the liner, the ESIPC few meters above, and the Cement Assurance Tool above the ESIPC.

The procedure to solve this would be to drill the $17^1/_2$" section normal and set the $13^3/_8$" casing at approximately 2,100 meters TVD. Then drill the $12^1/_4$" section down to 5-10 meters TVD above the Tor formation, as showed in figure 5.3.1a. Further, drill the last meters of the Lista formation and into the Tor formation with the drilling liner, as illustrated in figure 5.3.1b.

Figure 5.3.1: The first part of the procedure of including the C-Flex, ESIPC and the Cement Assurance Tool to the drilling liner.

As showed in figure 5.3.1b, the dual bottom-top wiper plug set is attached at the top of the liner with shear pins, which allow the circulation during drilling. The placement of the C-Flex port collar, ESIPC and the Cement Assurance Tool is right on top of each other above the Tor formation. Before drilling with the drilling liner, if there are no losses at this point, 5-10 meters TVD above Tor formation, the C-Flex, ESIPC and the Cement Assurance Tool should be placed in a way that they are located above this point when the liner is getting stuck, as illustrated in figure 5.3.2. Then there is a larger chance that the cement job through the ESIPC is being successful.
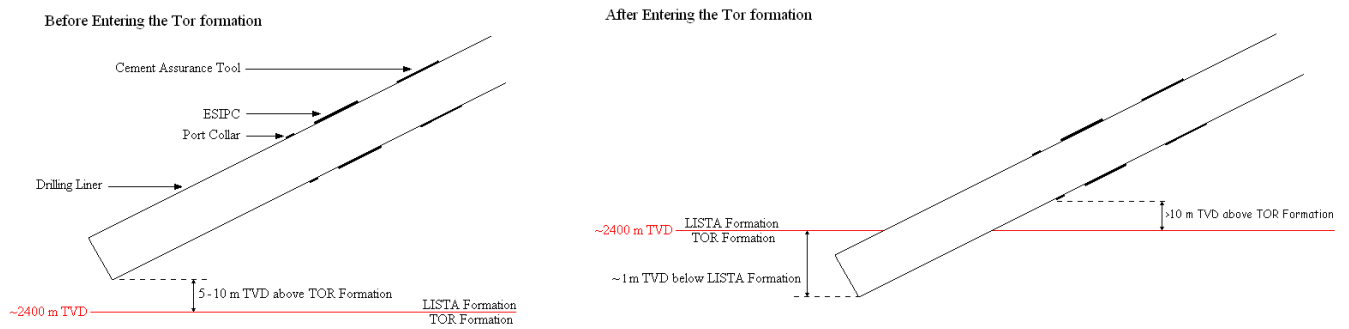
Figure 5.3.2: Illustrate the best placement of the C-Flex port collar, ESIPC and the Cement Assurance Tool on the drilling liner compared to the Tor formation, if there is not any loss circulation zone at the point where the drilling liner start to drill.

When the drilling liner is entering the Tor formation, it would have losses up to 100% as mentioned before. After some time, the drilling liner most likely gets stuck when the Lista formation most likely collapses around the liner, or by differential sticking. A ball must then be dropped, followed by the cement, as showed in figure 5.3.3a. The ball would land in the bottom cement plug, and the bottom plug would shear from the top plug and start moving downwards, as illustrated in figure 5.3.3b and figure 5.3.3c.
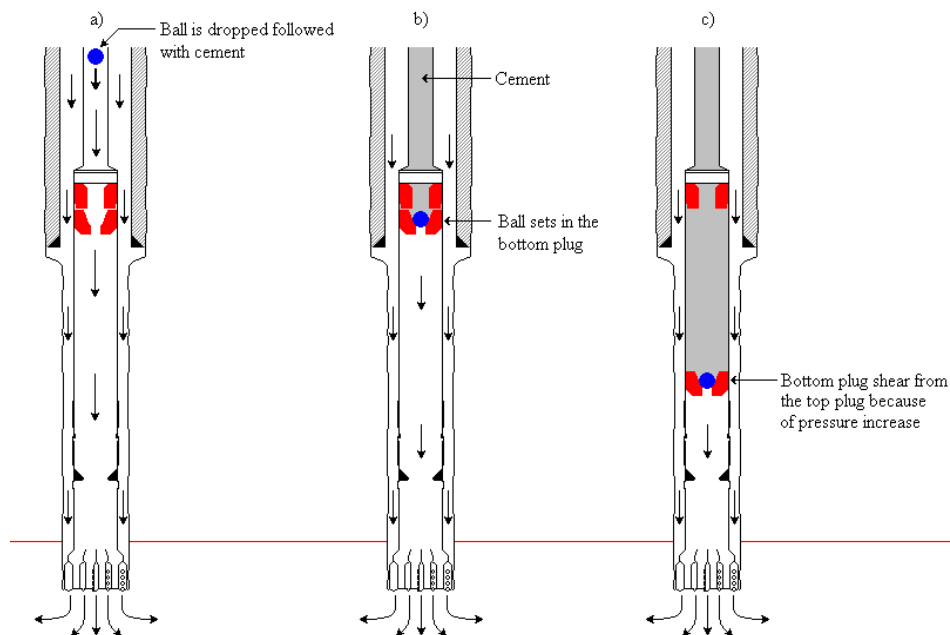
Figure 5.3.3: The second part of the procedure of including the C-Flex, ESIPC and the Cement Assurance Tool to the drilling liner.

When the bottom plug hits the plug seat in the ESIPC, it would seal inside the drilling liner and decrease the losses quite a lot, as illustrated in figure 5.3.4a. There would then be a pressure build-up at the ESIPC, and an activation port opens at a certain pressure and the cement inflates the packer, expanding it against the formation. Then the well is completely sealed as showed in figure 5.3.4b. The pressure from the cement would still increase, and at a certain higher pressure, a sliding sleeve is shifted open and the cement is pumped into the open-hole annulus, moving upwards as showed in figure 5.3.4c.

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a)

Bottom plug set at the plug seat in the ESIPC

Sealed inside Drilling Liner, not sealed in annulus

b)

After a given pressure, the cement is going into the Packer and expand it

No losses when the Packer is extending

c)

At a higher pressure, the Slinding Sleeve opens, and cement is injected onto the annulus
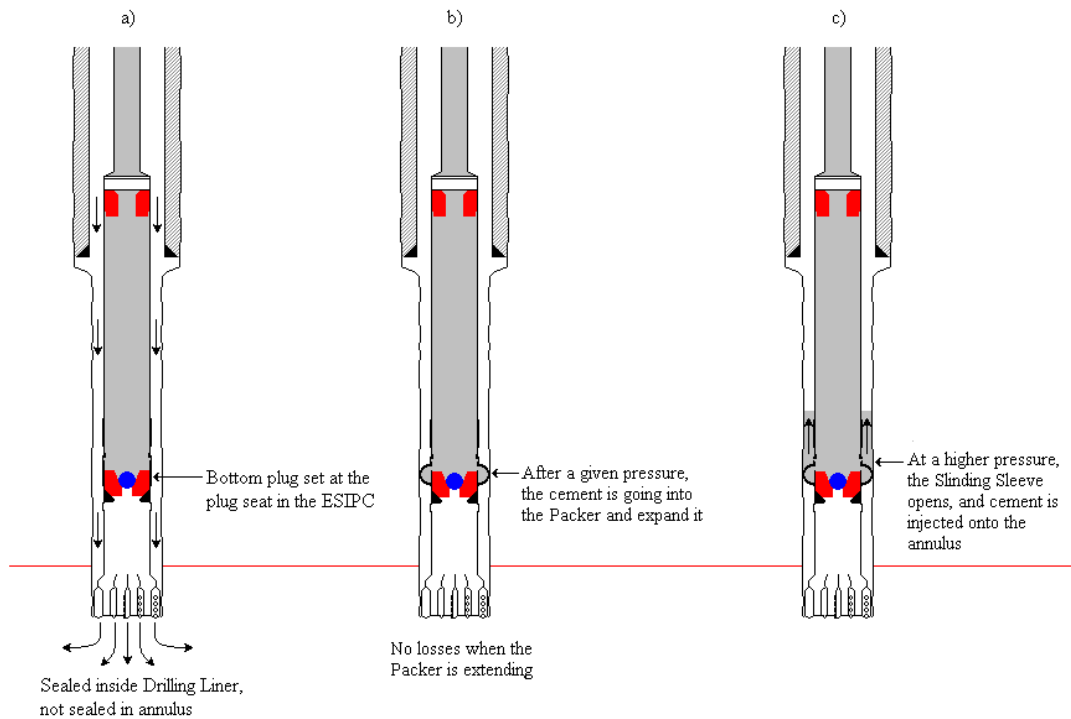
Figure 5.3.4: The third part of the procedure of including the C-Flex, ESIPC and the Cement Assurance Tool to the drilling liner.

Wiper dart is launched directly after the cement as showed in figure 5.3.5a. This dart will wipe the drillpipe and latch into the top cement plug, which will shear from the liner at a predetermined pressure, showed in figure 5.3.5b. The cement can be pumped into the annulus, with returns at surface giving an indication that the annulus is filled with cement as showed in figure 5.3.5c.

a)

Wiper plug is launched after the cement

b)

Displacing mud

The Wiper dart launched into the top plug

c)

Cement can be circulated to get an indication that the annulus is filled with cement
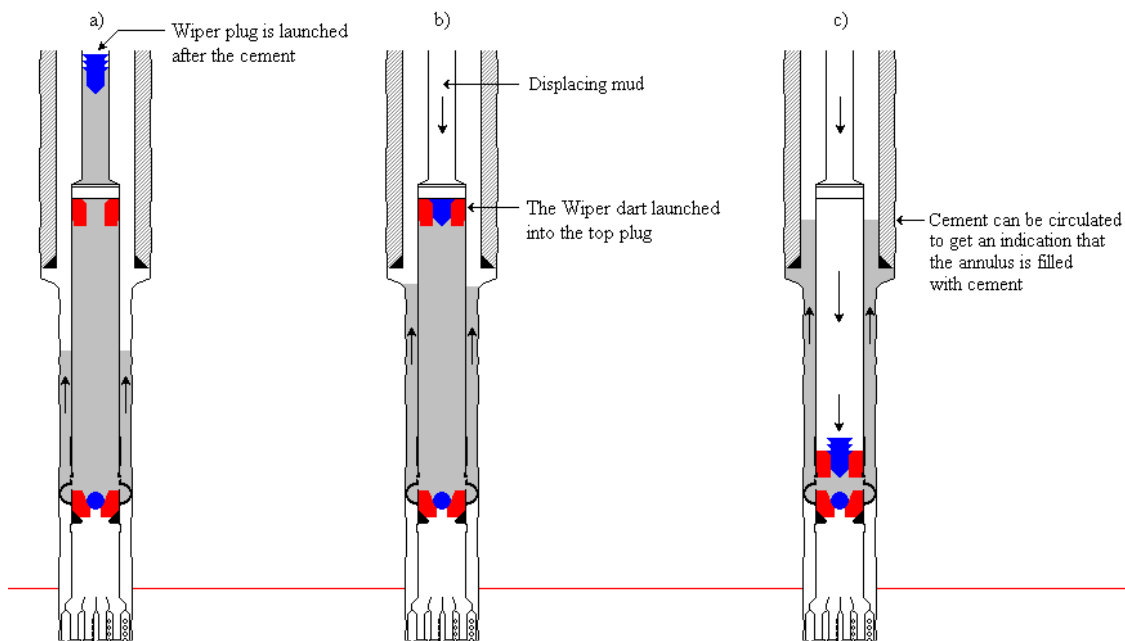
Figure 5.3.5: The fourth part of the procedure of including the C-Flex, ESIPC and the Cement Assurance Tool to the drilling liner.

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When the wiper dart with the top cement plug reaches the ESIPC, it closes the sliding sleeve as shown in figure 5.3.6a. The next step after the cement job, is to set the hanger and packer at the top of the liner, and pull the drillstring and the running tool as per conventional method as shown in figure 5.3.6b. The Wiper dart and plug are drilled out with an $8^1/_2$" BHA as shown in figure 5.3.6c.

a)   b)   c)

Hanger and Packer are
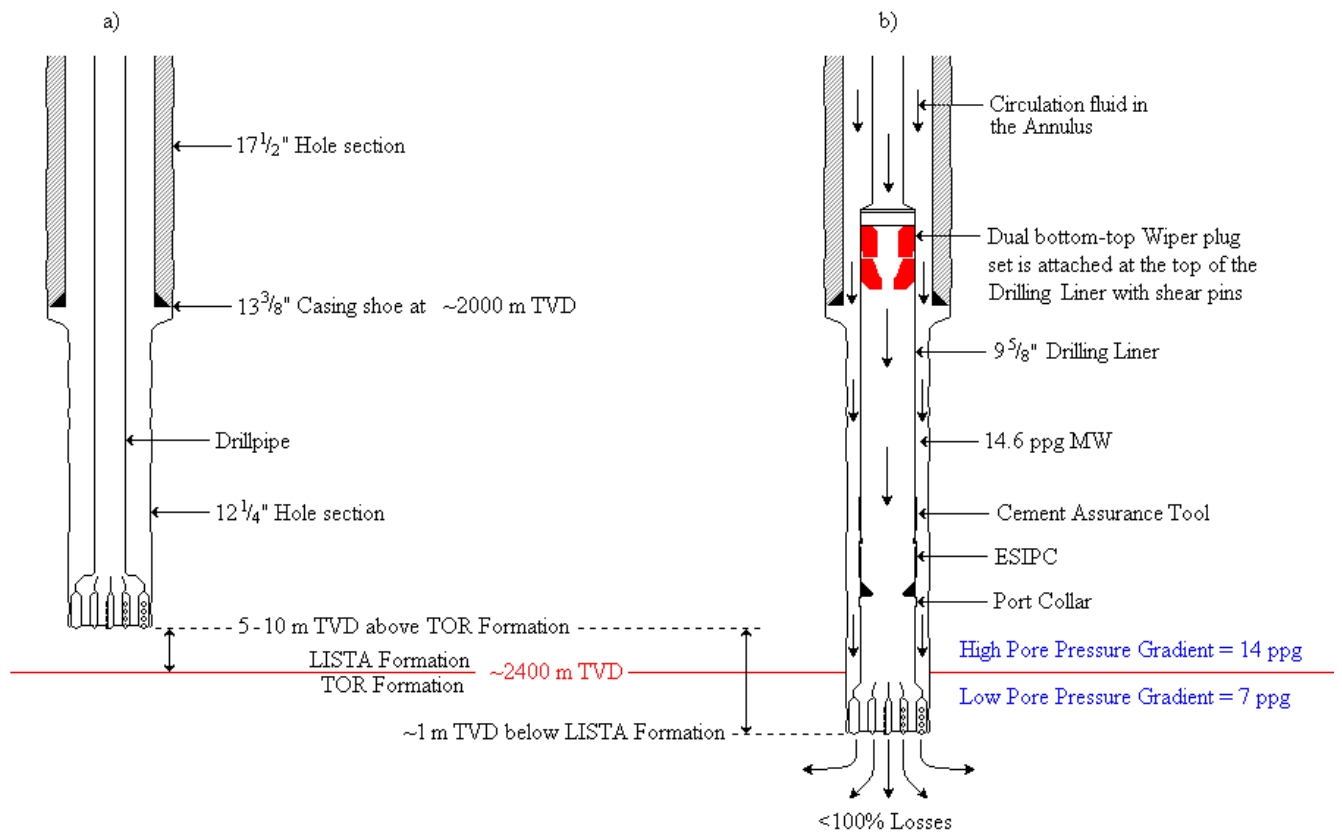set after the cement job

Drillpipe

The top plug has
closed the sliding
sleeve
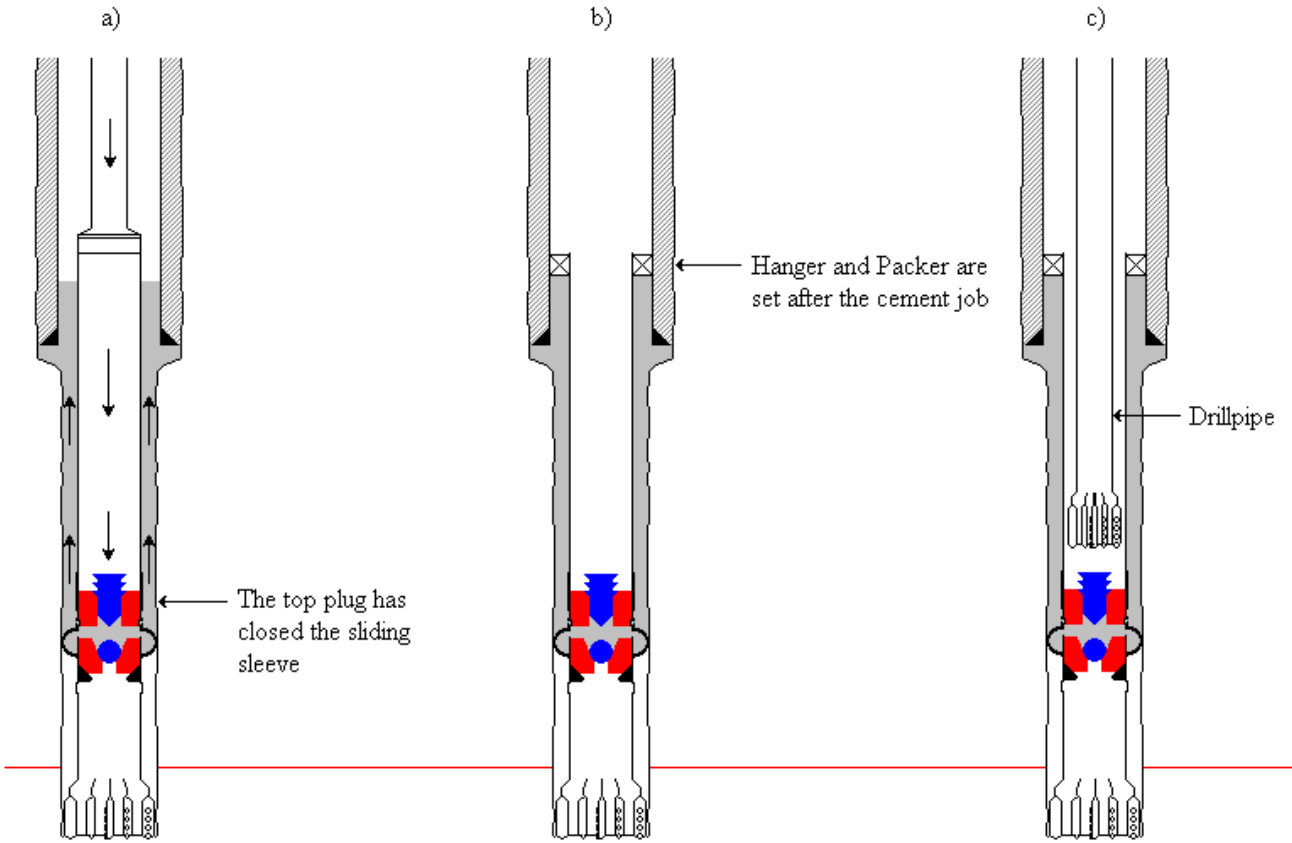
Figure 5.3.6: Fifth part of the procedure of including the C-Flex, ESIPC and the Cement Assurance Tool to the drilling liner.

The well is displaced to a lower mud weight when drilling out the plug set to decrease the risk of large losses, as showed in figure 5.3.7a. The next step would be to squeeze cement through the C-Flex port collar as conventional procedure, to increase the chance of getting a good integrity barrier in combining with the ESIPC. This is showed in figure 5.3.7b. When the squeeze job is finish, the next $8^1/_2$" section could be drilled, as showed in figure 5.3.7c.
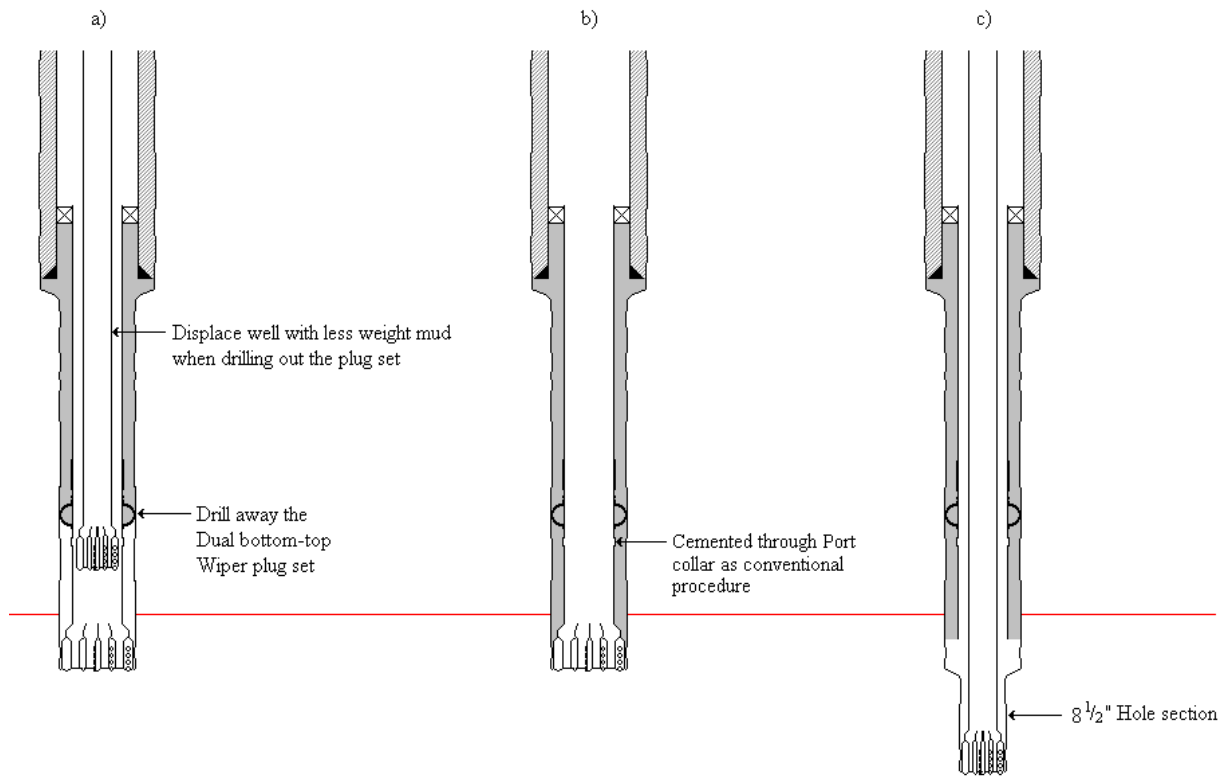
Figure 5.3.7: The last part of the procedure of including the C-Flex, ESIPC and the Cement Assurance Tool to the drilling liner.

The Cement Assurance Tool is just an extra safety in case the cement around the liner contracts and makes a micro-annulus, which could create a possible leak.

This option including the ESIPC, C-Flex and the Cement Assurance Tool in the drilling liner would most likely give the required integrity according to NORSOK. This integrity is very important to be able to increase the injection pressure to the required level. The positive with this method is the possibility to circulate the cement to the surface via the ESIPC, which could give an indication of a good cement column in the open-hole annulus.

Compared to the conventional method used on Valhall, this implementation option would require an extra trip if the extra cement squeeze job through the C-Flex port collar is performed.

5.4 Further Work

As mentioned before, at present time the ESIPC is not capable to be included on the drilling liner because of the large loads that it will be exposed to. Today, the ESIPC has been a cementing tool used along with Halliburton's Versaflex, which was their expandable liner hanger. First of all, the ESIPC is not designed to be rotated with a high torque as when drilling with a drilling liner. Also, the ESIPC is not designed for prolonged circulation that is required during drilling. When including the ESIPC in the drilling liner, the dual bottom-top wiper plug set has to be reinforced as well. When large losses occur, there would be large force acting on the wiper plug set, which could make it shear from the liner before it should.

There is a large risk pumping cement when the well has up to 100% losses, because if the ESIPC don't work properly, all the cement would most likely be squeezed into the reservoir. The amount of this cement job is much larger than the ordinary cement squeeze job through the C-Flex, and could cause problems to further operations. To make inclusion of the ESIPC less risky, the inflatable packer should be able to be inflated with mud instead of cement. Then it is possible to circulate and get an indication that the inflatable packer has sealed the annulus behind the drilling line before pumping cement. Also, the cement cannot be mixed before the drilling liner gets stuck because it may set too early. If the inflatable packer should be inflated with cement, the cement has to be finished mixed before the drilling liner gets stuck. If the inflatable packer could be inflated with mud, it would solve this issue.

Also, there is a very large differential pressure across the bottom plug and the plug seat when the cement plug lands, as illustrated in figure 5.4.1. The differential pressure, ΔP, is depending on the pore pressure in Tor formation, the density of the fluid above the plug and the extra pressure needed to pressure up the inflatable packer. ΔP could vary from 3,000 psi to 8,000 psi in worst case, and this large rate has to be taken into account when redesigning the ESIPC.
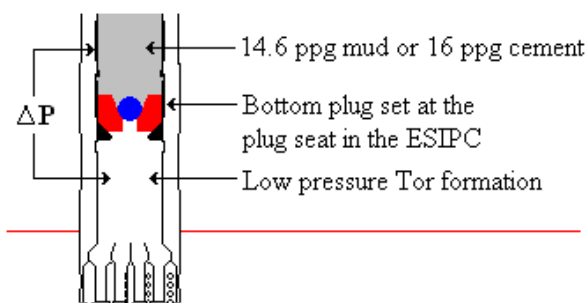
Figure 5.4.1: Illustrate the differential pressure that will act on the bottom plug and the plug seat.

To be able to use this option, the ESIPC and the dual bottom-top wiper plug set definitely needs a modification and redesign to be able to handle the large loads when including it in the drilling liner. This process means a near corporation with Halliburton since the patent of the ESIPC and the corresponding plug set is theirs. There must be a redesign and calculations to find out if it is possible to include it, followed by development of a prototype and perform a large amount of different tests to verify the quality. Redesigning and testing the ESIPC would cost an unknown amount of money that Halliburton most likely don't want to pay without a commitment from BP, and BP must evaluate the value of modifying the ESIPC to make this commitment. This cost has to be compared to the

value of solving the barrier challenge times the probability that it would work. To develop the ESIPC is a onetime cost, if it will work, the tool itself would not cost that much for every time it should be used. In the long term, there will be an economic benefit regarding the increased injection pressure.

First when this long process by redesigning and testing is done, it could be included in the drilling liner.

6 Conclusion and Recommendation

Conclusion;

- The best option to include in the present casing design on Valhall IP is to include the External Sleeve Inflatable Packer Collar (ESIPC), Cement Assurance Tool and C-Flex port collar with the drilling liner.

- This option would give a required barrier element with high integrity at top of the Tor formation according to NORSOK, and guarantee an increased injection pressure every time.

- The ESIPC makes it possible to pump the cement into the annulus with returns at surface, which would give an indication of how good the cement column behind the $9^5/_8$" drilling liner is.

- The Cement Assurance Tool, a thin Swellpacker placed above the ESIPC, would swell if any leak occurs in a micro-annulus between the liner and the cement.

- The C-Flex port collar, placed below the ESIPC, makes it possible to do an extra cement squeeze job, both additional to the main cement job through the ESIPC, or instead if the ESIPC fails.

- Since the ESIPC is not capable to be included in the drilling liner at present time, redesign and modifications is needed.

- Since Halliburton is the patent owner of the ESIPC, a corporation with them would be needed to be able to make this possible.

- When redesigning and modifying the ESIPC, the main issues would be the large torque it must handle during drilling, the plug seat inside the ESIPC, and the inflatable packer.

- The corresponding dual bottom-top wiper plug set must be reinforced as well because of the large forces acting on the plug when up to 100% losses occurs.

- If the inflatable packer could be inflated with mud instead of cement, it would make it more conventional, and there would be a less risk in case the ESIPC fails.

Recommendation;

- It is recommended to evaluate a redesign of the ESIPC with Halliburton for use in drilling liner at Valhall, due to the large forces acting on it during drilling.

- It is recommended to evaluate a redesign of the corresponding dual bottom-top wiper plug set for use in the drilling liner, because of the large forces acting on the plug during large losses, and when it is set in the ESIPC.

- It is also recommended to evaluate use of the Cement Assurance Tool and C-Flex with the ESIPC, because they can give an extra insurance if the ESIPC fails, or if there is a leak in a micro-annulus between the liner and the cement.

Abbreviations

AI	Acoustic Impedance
API	American Petroleum Institute
BHA	Bottom-Hole Assembly
BHD_s	Bottom-Hole Density of the fluid including solids
BHT	Bottom-Hole Temperature
boe	Barrels of Oil Equivalent
BOP	Blow-Out Preventer
BPA-D-001	BP Amoco Drilling and Well Operation Policy
BPA-D-003	BP Amoco Casing Design Manual
BRT	Below Rotary Table
CBL	Cement Bond Log
CFER	Centre for Frontier Engineering Research
CHDT	Cased-Hole Dynamics Tester
Cl	Chlorine
CO_2	Carbon dioxide
cP	Centi Poise
CT	Coiled Tubing
DnV	Det Norske Veritas
DP	Drill Platform
DST	Drill Stem Test
E&P	Exploration and Production
ECD	Equivalent Circulation Density
EMW	Equivalent Mud Weight
ESIPC	External Sleeve Inflatable Packer Collar
ESP	Electric Submersible Pump
FPSO	Floating Production Storage and Offloading
ft	Feet
ft.Ibs	Foot-Pound, Torque
GPa	Giga Pascal
H_2S	Hydrogen Sulphide
IADC	International Association of Drilling Contractors
Ibs	Pounds
ID	Inner Diameter
IEC	International Electrotechnical Commission
IP	Injection Platform
ISIP	Initial Shut-In Pressure
ISO	International Organization for Standardization
kHz	Kilo Hertz
LOT	Leak-Off Test
MD	Measured Depth

MPa	Mega Pascal
MRayl	One unit of Acoustic Impedance
MSL	Mean Sea-Level
mV	Milli Volt
MW	Mud Weight
N_2	Nitrogen
NCS	Norwegian Continental Shelf
NOK	Norwegian Kroner
NORSOK	Norsk Sokkels Konkurranseposisjon
NPD	Norwegian Petroleum Department
OD	Outer Diameter
OLF	The Norwegian Oil Industry Association
OOC	Onshore Operation Centre
OTC	Offshore Technology Conference
PBR	Polished-Bore Receptacle
PCP	Production and Compression Platform
PDC	Polycrystalline Diamond Compact
PIP	Trademarked name for "Pin Point Injection Packer"
ppf	Pounds per Feet
ppg	Pounds per Gallon
PSA	Pressure Setting Assembly
psi	Pounds per Square Inches
QP	Quarters Platform
RKB	Rotary Kelly Bushing
ROP	Rate Of Penetration
RPM	Revolutions per minute
RV	Ranking Value
s.g.	Specific Gravity
SET	Solid Expandable Technology
SPE	Society of Petroleum's Engineers
TD	Total Depth
TVD	True Vertical Depth
UTG	Upstream Technology Group
VAM	Pipe Company
WOC	Weight On Cement
WP	Well Platform
$ZnBr_2$	Zink Bromid

Nomenclature

English Symbols

˚C	Degrees Celsius	p.49
˚F	Degrees Fahrenheit	p.49
A_i	Inside area [in^2]	p.29
A_o	Outside area [in^2]	p.29
A_s	Area of steel [in^2]	p.27
C	Material constant	p.9
C_m	Compressibility of the rock [psi^{-1}]	p.10
D	Outer diameter [in]	p.9
d	Mud weight [ppg]	p.22
D	True vertical depth [ft]	p.22
D/t	Ratio of the outer diameter compared to the wall thickness of the pipe	p.17
D_{wp}	Weak point depth [ft]	p.23
E	Young's modulus [psi]	p.9
F_a	Total axial load [Ibs]	p.27
F_c	Critical buckling force [Ibs]	p.29
$F_{eff.}$	Effective tension [Ibs]	p.29
F_t	Axial force at the point of interest [Ibs]	p.29
G	Shear modulus [psi]	p.69
gg	Gas gradient [psi/ft]	p.23
H	Height of gas column below weak point [ft]	p.23
h_i	Initial height of the rock [ft]	p.10
I	Pipe cross-sectional moment of inertia [in^4]	p.30
k	Variable parameter	p.29
K_{fr}	Bulk modulus of the rock framework [psi]	p.9
K_s	Bulk modulus of solids [psi]	p.9
L	Length [ft]	p.29
M	Rock deformation modulus [psi]	p.9
M_e	Elastic deformation modulus in rock [psi]	p.9
M_{e-p}	Elastic-Plastic deformation modulus in rock [psi]	p.9
M_p	Plastic deformation modulus in rock [psi]	p.9
P	Pore pressure [psi]	p.8
P	Pressure drop [psi]	p.22
P_e	External stress [psi]	p.27
P_f	Expected formation pressure [psi]	p.23
P_i	Internal stress [psi]	p.27
$P_{leak-off}$	Leak-off pressure [psi]	p.22
P_{max}	Maximum pore pressure [psi]	p.22

Greek Symbols

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Appendix A

Argumentation of the different ranking values of each option in section 5.1 is given in table A1.

Table A1: Show the argumentation of ranking the different options.

Options	Argumentation of the ranking
ESIPC, Cement Assurance Tool and C-Flex	
Injection Pressure	Very good, this application has definitely possibility to increase the injection pressure to a wanted level.
Integrity, Theoretical Effect	Very good, has a possibility to provide a good integrity along with the cement squeeze job through the C-Flex, and with an extra assurance with the Cement Assurance Tool if a leak through micro-annulus occurs.
Operation lifetime	Very good, the ESIPC will last for a long time period because it will provide a good cement column behind the liner, the extra cement squeeze job through the C-Flex could give an extra support, and the Cement Assurance Tool will seal of the micro-annulus if there occur a leak through the ESIPC.
Contingency	Average, the OD of the packer is unknown due to redesigning, could have problems to get through the $11^3/_4$" contingency liner.
Integrity, Feasibility	Bad, difficult to claim that it will work without necessary upgrading and testing.
Installation	Average, the cement squeeze job through the C-Flex is a little difficult but it is not difficult to install the ESIPC or the Cement Assurance Tool on the drilling liner.
Cost	Bad, has an unknown cost but would probably be expensive since modifications must be performed, following with testing before tryout, and the additional cement squeeze job through the C-Flex would require an extra trip, but the Cement Assurance Tool is not expensive.
Summary	By combining ESIPC, Cement Assurance Tool and the C-Flex with the drilling liner, would give an extra insurance in case if there should be a leak pass the packer in the ESIPC and it is possible to do an extra cement squeeze job through the C-Flex. Overall, this would be a very good solution to provide a good barrier at the top of Tor formation. This would be an implementation options that guarantee the wanted injection pressure every time, as long as it could handle a contingency situation, and will with a high probability last as long as the well itself. This implementation did get the highest ranking of all the implementation options presented, and would be the most recommended options on Valhall because of the guarantee of an increased injection pressure. But as mentioned before, the maximum injection pressure is

	depending on what part of the Valhall field the well is located. Total ranking score; 317 of possible 450, meaning an average ranking of 7.04, which is good.

ESIPC and C-Flex	
Injection Pressure	Very good, this application has definitely possibility to increase the injection pressure to a wanted level.
Integrity, Theoretical Effect	Very good, has a possibility to provide a good integrity along with the cement squeeze job through the C-Flex.
Operation lifetime	Very good, the ESIPC will last for a long time period because it will provide a good cement column behind the liner, and the extra cement squeeze job through the C-Flex could give an extra support.
Contingency	Average, the OD of the packer is unknown due to redesigning, could have problems to get through the $11^3/_4$" contingency liner.
Integrity, Feasibility	Bad, difficult to claim that it will work without necessary upgrading and testing.
Installation	Average, the cement squeeze job through the C-Flex is a little difficult but it is not difficult to install the ESIPC on the drilling liner.
Cost	Very Bad, has an unknown cost but would probably be expensive since modifications must be performed, following with testing before tryout, and the additional cement squeeze job through the C-Flex would require an extra trip.
Summary	By combining ESIPC and the C-Flex with the drilling liner, there is a possibility to do the conventional cement squeeze job through the C-Flex additionally to the ESIPC or in worst case alone if the ESIPC fails. If this squeeze job is done additionally, it would require an additional run compared to conventionally method, and it would then be more expensive. But it would be an implementation options that guarantee the wanted injection pressure every time, and could be a recommended options on Valhall. Total ranking score; 309 of possible 450, meaning an average ranking of 6.87, which is good.

ESIPC	
Injection Pressure	Very good, this application has definitely possibility to increase the injection pressure to a wanted level.

Integrity, Theoretical Effect	Very good, has a possibility to provide a good integrity.
Operation lifetime	Very good, the ESIPC will last for a long time period because it will provide a good cement column behind the liner.
Contingency	Average, the OD of the packer is unknown due to redesigning, could have problems to get through the $11^3/_4$" contingency liner.
Integrity, Feasibility	Bad, difficult to claim that it will work without necessary upgrading and testing.
Installation	Good, it is not difficult to install the ESIPC on the drilling liner.
Cost	Bad, has an unknown cost but would probably be expensive since modifications must be performed, following with testing before tryout.
Summary	By combining ESIPC with the drilling liner could be a very good solution to provide a good barrier at the top of Tor formation. Theoretically this tool will seal of the well from the reservoir, both inside and outside the liner, and give a good cement job from its point and to the top of the liner. The cement could be circulated out which gives an verification that there is a barrier at the depth of the ESIPC. This tool scored low at feasibility, because at present time it is not strong enough for this purpose, and it can cost an unknown amount of money to make it includable. The packer OD could then be an unknown size, and there is no guarantee that it would go through a contingency liner before it is finished redesigned. But if the ESIPC was redesigned and modified, it would be an implementation options that guarantee the wanted injection pressure every time, and would be a recommended options on Valhall. Total ranking score; 305 of possible 450, meaning an average ranking of 6.78, which is good.

Shale Annular Barrier, Cement Assurance Tool and C-Flex	
Injection Pressure	Average, can make it possible to increase the injection pressure if the shale provide a seal behind the liner.
Integrity, Theoretical Effect	Very good, if the shale is verified as a barrier, it would provide a good integrity and the cement squeeze job through the C-Flex could be successful because of the collapsed shale, with an extra safety with the Cement Assurance Tool.
Operation lifetime	Very Good, if the shale has collapsed or swallow around the liner, it would last in a very long time, with extra help from the cement and the Cement Assurance Tool that seal of any leak in a micro-annulus between the liner and the cement.

Contingency	Very good, the Cement Assurance Tool would not have any problems to get through the $11^3/_4$" contingency liner.
Integrity, Feasibility	Average, it is not certain that the Lista shale act as same as other shale formations which has been verified as barriers, but the Cement Assurance Tool along with the cement squeeze job through the C-Flex could provide integrity.
Installation	Average, the cement squeeze job through the C-Flex is a little difficult, and the extra logging and pressure testing is taking some extra time, but the Cement Assurance Tool is installed easily.
Cost	Bad, the shale annular does not cost anything, but the additional pressure testing and logging is expensive, and the extra cement squeeze job, but the Cement Assurance Tool is not expensive.
Summary	By combining shale annular barrier, Cement Assurance Tool and the C-Flex with the drilling liner only gives an extra possibility to seal of the annulus and provide a barrier. It is still not any guarantee that a barrier is created and the cement is depending on the shale to settle. As long as the Lista shale is so unpredictable, it would not be an implementation options that guarantee the wanted injection pressure every time, and would not be a recommended options on Valhall before the Lista shale has been investigated through other wells. Total ranking score; 296 of possible 450, meaning an average ranking of 6.58, which is good.

Shale Annular Barrier and C-Flex	
Injection Pressure	Average, can make it possible to increase the injection pressure.
Integrity, Theoretical Effect	Very good, if the shale is verified as a barrier, it would provide a good integrity and the cement squeeze job through the C-Flex could be successful because of the collapsed shale.
Operation lifetime	Very good, if the shale has collapsed or swallow around the liner, it would last in a very long time, with extra help from the cement.
Contingency	Very Good, is not dependent of the contingency.
Integrity, Feasibility	Average, it is not certain that the Lista shale act as same as other shale formations which has been verified as barriers, but the cement squeeze job through the C-Flex could provide integrity.
Installation	Average, the cement squeeze job through the C-Flex is a little difficult, and the extra logging and pressure testing is taking some extra time.

Cost	Bad, the shale annular does not cost anything, but the additional pressure testing and logging is expensive along with the cement squeeze job through the C-Flex.
Summary	By combining the shale annular barrier and the C-Flex with drilling liner is most likely the method done today, the difference is that the shale is not been verified with logging. This is a good solution if the shale has created a barrier around the liner, and the cement is set where it is supposed to. But again, there is no guarantee that a barrier is created, and with logging there is only possible to confirm the barrier or not. As long as the Lista shale is unpredictable, it would not be an implementation options that guarantee the wanted injection pressure every time, and would not be a recommended options on Valhall before the Lista shale has been investigated through other wells. Total ranking score; 294 of possible, meaning an average ranking of 6.53 which is good.

Cement Assurance Tool and C-Flex	
Injection Pressure	Good, can make it possible to increase the injection pressure.
Integrity, Theoretical Effect	Average, the cement job through the C-Flex would still be questionable even the Cement Assurance Tool would seal the micro-annulus. It is an uncertainty how and where the micro-annulus is created.
Operation lifetime	Average, the Cement Assurance Tool should last quite long as well as ordinary Swellpackers, but this is only theoretically.
Contingency	Very Good, the Cement Assurance Tool would not have any problems to get through the $11^3/_4$" contingency liner.
Integrity, Feasibility	Very good, can provide a good integrity.
Installation	Average, it is very easy to install the Cement Assurance Tool, but the cement squeeze job through the C-Flex is a little more difficult.
Cost	Average, by using C-Flex, an additional trip is required, but the Cement Assurance Tool is not expensive.
Summary	By combining the Cement Assurance Tool and C-Flex in combination with drilling liner, could maybe give a good barrier and provide an increased injection pressure. But the cement squeeze job through the C-Flex would still be questionable and it would then not guarantee increasing the injection pressure every time. Total ranking score; 281 of possible 450, meaning an average ranking of 6.24,

	which is good.

ThermaSet and C-Flex	
Injection Pressure	Average, can make it possible to increase the injection pressure.
Integrity, Theoretical Effect	Average, if the ThermaSet is made with a high viscosity as possible, it could set more easily than the cement and provide a good integrity, but there are no guarantees that it would.
Operation lifetime	Very good, the ThermaSet could handle more stress over a long time period compared to cement, and would not create micro-annulus like the cement.
Contingency	Very Good, is not dependent of the contingency.
Integrity, Feasibility	Average, there is not any guarantee that the ThermaSet would make a better integrity than conventionally cement.
Installation	Average, the cement squeeze job through the C-Flex is a little difficult but the ThermaSet is squeezed conditionally through the C-Flex as the cement.
Cost	Bad, the ThermaSet is very expensive, and the cement squeeze job through the C-Flex requires an extra trip.
Summary	By combining ThermaSet and C-Flex with the drilling liner does not give any more guarantees than by using conventional cement through the C-Flex, but will handle shear stresses in a much longer time period than the cement. Since all of the squeeze jobs through the C-Flex are questionable, it would not be an implementation options that guarantee the wanted injection pressure every time, and would not be a recommended options on Valhall. Total ranking score; 244 of possible 450, meaning an average ranking of 5.42 which is average.

Swellpacker and C-Flex	
Injection Pressure	Average, can make it possible to increase the injection pressure.
Integrity, Theoretical Effect	Good, will theoretically provide integrity in the well.
Operation lifetime	Good, the Swellpackers should last quite long, but this is only theoretically.
Contingency	Not applicable, by using ordinary Swellpacker, the OD of the packer has to fit inside the $11^3/_4$" contingency liner and still swell to $12^1/_2$" wellbore, which is impossible.
Integrity, Feasibility	Average, it is possible to include this technology.

Installation	Average, it is very easy to install the Swellpackers, but the cement squeeze job through the C-Flex is a little more difficult.
Cost	Average, by using C-Flex an additional trip is required, but the Swellpacker is not expensive.
Summary	By combining the Swellpacker and C-Flex to the drilling liner could be a solution to make a good barrier at the top of the Tor formation, and provide a higher injection pressure. The cement squeeze job through the C-Flex would be good if the Swellpacker has swelled to wellbore. But since the situation at Valhall is what it is, it could be difficult. And since this Swellpacker does not go through a contingency liner, it would not be an implementation options that guarantee the wanted injection pressure every time, and would not be a recommended options on Valhall. Total ranking score; 216 of possible 450, meaning an average ranking of 4.80, which is average.

Swellpacker	
Injection Pressure	Average, can make it possible to increase the injection pressure.
Integrity, Theoretical Effect	Average, will theoretically provide integrity.
Operation lifetime	Good, the Swellpackers should last quite long, but this is only theoretically.
Contingency	Not applicable, by using ordinary Swellpacker, the OD of the packer has to fit inside the $11^3/_4$" contingency liner and still swell to $12^1/_2$" wellbore, which is impossible.
Integrity, Feasibility	Average, it is possible to include this technology.
Installation	Good, it is very easy to install the Swellpackers and do not use any additional rig-time.
Cost	Good, Swellpackers are not expensive.
Summary	By combining the Swellpacker to the drilling liner could be a solution to make a good barrier at the top of the Tor formation, and provide a higher injection pressure. But since the situation at Valhall is what it is, it could be difficult. Since this Swellpacker does not go through a contingency liner, it would not be an implementation options that guarantee the wanted injection pressure every time, and would not be a recommended options on Valhall. Total ranking score; 207 of possible 450, meaning an average ranking of 4.46, which is average.

Shale Annular Barrier	
Injection Pressure	Bad, since the Lista shale is unpredictable, it cannot guarantee an increased injection pressure.
Integrity, Theoretical Effect	Bad, the probability that the shale is a verified barrier by itself is quite low. It can take several years before it seal properly and provide a good barrier.
Operation lifetime	Very good, if the shale has collapsed or swallows around the liner, it would last in a very long time and would be self-healing.
Contingency	Very Good, is independent of the contingency.
Integrity, Feasibility	Bad, it is not certain that the Lista shale act the same as other shale formations which has been verified as barriers.
Installation	Average, the additional pressure testing and logging takes extra time.
Cost	Bad, the shale annular does not cost anything, but the additional pressure testing and logging is expensive.
Summary	By combining the shale annular barrier with drilling liner would theoretically be the best implementation solution on Valhall, because it happens without any interference, it is self-healing and does not cost anything. The negative is that nothing can control it, and there is no guarantee that the Lista shale would create an annular barrier as wanted. The only way to find out is to run cement bond log and pressure tests to verify the barrier. If there is no barrier behind the drilling liner, there is not possible to get any barrier behind the liner. As long as the Lista shale is so unpredictable, it would not be an implementation options that guarantee the wanted injection pressure every time, and would not be a recommended options on Valhall.
	Total ranking score; 198 of possible 450, meaning an average ranking of 4.40 which is average.

C-Flex and foundation	
Injection Pressure	Average, can make it possible to increase the injection pressure.
Integrity, Theoretical Effect	Bad, even the foundation could provide a more controlled cement job through the C-Flex, it would still be questionable. It depends on if the well is in communication with the reservoir, which is most likely.
Operation lifetime	Average, the cement squeeze job through the C-Flex is questionable.
Contingency	Very Bad, the foundation could not pass through the $11^3/_4$" contingency liner if it should be used as its purpose.
Integrity, Feasibility	Average, can provide integrity.

Installation	Average, the cement squeeze job through the C-Flex is a little difficult, but the installation of the foundation is easy.
Cost	Good, by using C-Flex, an additional cement run is needed, but the foundation is not expensive.
Summary	By combining the C-Flex and the foundation with the drilling liner could provide a better cement job through the C-Flex, but it would not give any guarantee for a good cement job to be able to increase the injection pressure. The foundation would not be able to go through the contingency liner without losing its purpose, and would not be an implementation options that guarantee the wanted injection pressure every time, and would not be a recommended options on Valhall. Total ranking score; 181 of possible 450, meaning an average ranking of 4.02, which is average.

Expandable liner hanger	
Injection Pressure	Not applicable, would not be a direct solution to increase the injection pressure because it would be placed above the $13^3/_8$" shoe which already is a barrier.
Integrity, Theoretical Effect	Very bad, could make a barrier at the top of the liner but would not make any barrier at top of the Tor formation.
Operation lifetime	Average, the area where the expandable liner hanger is usually not exposed to shear stresses in the formation.
Contingency	Average, this technology does not necessary have larger OD than the conventional used liner hangers.
Integrity, Feasibility	Very good, it is easy to include this technology.
Installation	Very Good, the installation process is quick and effective.
Cost	Good, it is not very expensive technology.
Summary	By combining expandable liner hanger to the drilling liner is a good idea, and could replace the conventional hanger packer that often is seemed as a weak point because of the rotation. However, this would not be a direct solution to increase the injection pressure even it scored good on the minor issues. As long this technology could not increase the injection pressure, it would not be the recommended implementation options on Valhall. Total ranking score; 168 of possible 450, meaning an average ranking of 3.73, which is bad.

DuraWAV	
Injection Pressure	Not applicable, would not be a direct solution to increase the injection pressure.
Integrity, Theoretical Effect	Bad, this technology would not provide a good barrier, only a larger resistance against collapse load.
Operation lifetime	Very good, will last longer than conventional casings due to shear stress and compactions of the formations.
Contingency	Average, would have a small increase in OD than conventional casings.
Integrity, Feasibility	Bad, the DuraWAV would not be any better than a conventional liner to provide a barrier.
Installation	Average, is just like conventional casings.
Cost	Bad, little more expensive than conventional casings.
Summary	By combining DuraWAV with the drilling liner would not make any sense with respect to increasing the injection pressure. It is positive according to handle more shear stress than conventional liners, but would not be an implementation options that guarantee the wanted injection pressure every time, and would not be a recommended options on Valhall. Total ranking score; 165 of possible 450, meaning an average ranking of 3.67 which is bad.

Expandable liner	
Injection Pressure	Very bad, would not be able to be included as a solution to increase the injection pressure.
Integrity, Theoretical Effect	Very bad, this technology will not provide a good barrier at present day.
Operation lifetime	Bad, the quality of the expanded pipe is questionable due to collapse failure.
Contingency	Bad, the expansion cone could have problems to get through the $11^3/_4$" contingency liner, depending on what size of drilling liner that should be used.
Integrity, Feasibility	Bad, it is not easy to include this technology to provide integrity.
Installation	Good, there is simple installation method due to expandable technology.
Cost	Average, the expandable liner does not cost that much more than the heavy weighted liner used today.
Summary	By combining expandable liner with the drilling liner would not work at Valhall, mostly because of situation on Valhall today, and the technology has

	is not been implemented yet. To be able to make this implementation option work, there has to be a solution that makes it possible to expand the liner all the way down to the bit, which mean inside the Tor formation. As long it does not work, it would not be able to create a good barrier and increase the injection pressure. Total ranking score; 113 of possible 450, meaning an average ranking of 2.51, which is bad.