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Author: Monika Saevareid	………………………………………… (signature of author)

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Abstract

Drilling in high-pressure high-temperature (HPHT) wells present many economical, technical and operational challenges. The wells are usually located in deep water—where the total well cost and trip times are increased. Well planning of these wells require special considerations of three factors: safety, efficiency and cost.

The production string is one of the most important aspects of well planning in HPHT wells. A failure of the production string may have disastrous results, since the string serves as the backup protection for the tubing.

The selection of a long casing string versus a liner tieback string is a common discussion in the oil industry. Several factors have to be accounted for prior to the final selection. The liner option will for instance provide more barriers against annular flow, but it is also a more complex and time-consuming operation to perform. Long casing string solution provides better well integrity over the lifetime of a well, but is dependent upon a successful primary cement job.

It is easier to achieve a successful primary cement job with the liner than with the long casing string. The space between the casing and drill pipe is much bigger when running in hole with the liner, which will generate less surge pressure and open up for a higher flow rate during the cement job. The high flow rate during cementing, normally improves the quality of the cement job.

In HPHT wells there is in general tighter clearance in the operating drilling window. Proper control of Equivalent Circulating Density (ECD) is of major importance when it comes to drilling safely and efficient. Liner provides reduced ECD, resulting in less risk for losses both while running in hole and cementing.

Although the liner comes with several advantages, the long string option is operationally easier and is less time consuming. My opinion is that long string option is the preferred one, assuming that the formation strength is sufficient for the cement job.

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Abbreviations

- APB-Annular Pressure Buildup
- CBL- Cement Bond Log
- ECD- Equivalent Circulating Density
- ESD- Equivalent Static Density
- FIT- Formation Integrity Test
- HPHT- High Pressure High Temperature
- LOT- Leak Off Test
- LTP- Liner Top Packer
- MD-Measured Depth
- OBM- Oil Based Mud
- PBR- Polished Bore Receptacle
- SF- Safety Factor
- SG- Specific Gravity
- TOC- Top Of Cement
- TVD- True Vertical Depth
- ULS- Ultra Sonic Log
- WBM- Water based mud

Introduction

Drilling in HPHT wells present difficult challenges, because of the high pressures and temperatures experienced in these wells. The pressure and temperature affects the rheological properties of the drilling fluid. Typical deep water pore pressure and fracture gradient profiles result in a narrow drilling window. The Equivalent Circulating Density (ECD) management is thereby of uppermost important in these wells. The high cost of HPHT wells demands a high rate completion for economic payback. The selection of production casing for these wells is therefore discussable with respect to saving time and money.

The failure probability of casing collapse is high in HPHT wells because of cementing complications and the operational environment. The cement sheath plays an important role in maintaining wellbore integrity. Primary cementing is a critical operation during construction of a well. The cement should provide structural integrity to the well and a continuous impermeable hydraulic seal in the annulus to prevent uncontrolled flow of reservoir fluids behind the casing. The downhole variation of pressure and temperature in HPHT affects the cement by shrinking and stress changes.

Design problems in HPHT wells have necessitated the use of liner and tieback strings. The selection of a long casing string versus a liner in combination with a tieback string is a common discussion in the oil industry. The thesis will discuss the selection of production string configurations, whether it is more preferable to select a liner in combination with a tieback strings rather than a full string casing. Concern will primarily be on the procedures, cementing operations and why liner often is run instead of the full string casing (Yetunde et al. 2011; Miller et al. 2005; Zhaoguang et al. 2012; West et al. 1966).

1 HPHT wells

1.1 General

The Norwegian Petroleum Industry has developed NORSOK standards to ensure adequate safety, value adding and cost effectiveness for the petroleum industry, developments and operations. According to NORSOK D-010 a HPHT well is defined as a well drilled in a formation with expected shut-in wellhead pressure greater than 690 Bar and/or a bottom hole temperature in excess of 150° C.

HPHT wells impose several challenges compared to conventional wells, because of the high pressures and temperatures in these wells. To mention some of these challenges:

- High temperature and pressure impact mud properties.
- The operational drilling window is in general narrow. Therefore ECD management is important.
- Ballooning effects.
- Temperature and pressure affects the mud weight and ECD.
- Rheological properties must be optimized to reduce ECD, and also to prevent barite sag.
- Gas diffusion during overbalanced condition.
- The influx are infinite soluble with Oil Based Mud (OBM), when gas/oil/condensate are below the dew point conditions downhole and will release the influx close to surface. The hydrocarbon dew point is the temperature at which the hydrocarbon components of any hydrocarbon-rich gas mixture, such as natural gas, will start to condensate out of the gaseous phase.

The drilling window in these wells is very often narrow. Both the mud weight and the rheology are difficult to control under such extreme conditions. Drilling problems very often experienced are losses, gains and barite sag. These problems can have a significant economic impact on the operation. In order to mitigate for these

challenges, very time consuming procedures has to be followed. If these problems are not managed properly, they can in worst-case scenario lead to loss of the well.

Despite the challenges with these wells interest has been high and the number of HPHT wells been drilled over the years have grown remarkable (Schlumberger 2016; Rommetveit et al. 2003).

1.1.1 Specification and qualification

The NORSOK Standard D-010 has set guidelines for specification and qualification for equipment and fluids that are used or installed in HPHT wells. These guidelines have special emphasis on:

- Sealing capability of metal-to-metal seals as a function of wellbore fluids, pressure and temperature.
- Clearance and tolerances as a result of temperature and differential pressure exposure.
- Deterioration of elastomer seals and components as a result of temperature/pressure exposure time and wellbore fluids.
- Packer fluid selection and design including hydrate prevention.
- Cement strength retrogression.
- Wellhead growth.
- Impact of depleted reservoir.
- Stability of explosive and chemical perforating charges as function of temperature, pressure and exposure time.

1.1.2 Operational Drilling Window

According to the International Association of Drilling Contractors, the operational drilling window is the difference between the maximum pore pressure and the minimum effective fracture pressure. In HPHT wells, the operational drilling window between pore pressure and fracture pressure is narrow— the mud weight must be adjusted to keep the hydrostatic pressure within the safe drilling window.
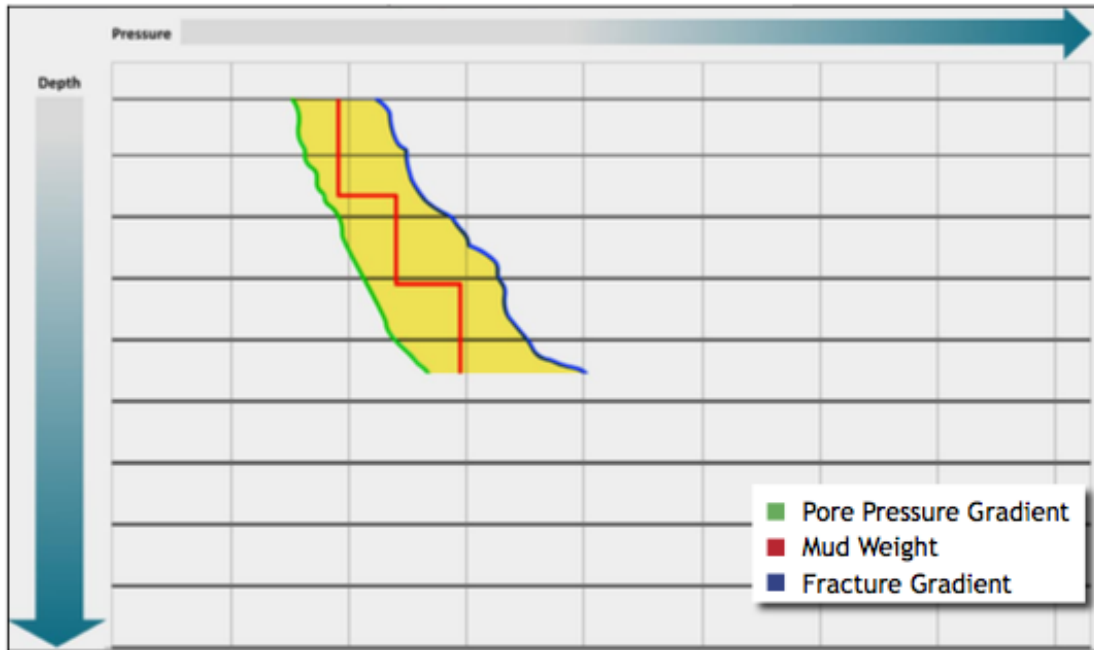
Figure 1 Narrow Drilling Window (Chief Counsels Report 2011).

1.2 Challenges with a HPHT well

Over pressurized formations is one of the main hazards when drilling a HPHT well. When formation fractures pressure at one location in the wellbore is close to the pressure in the same wellbore, it can lead to a kick incident or drilling fluid loss. This requires a very accurate control of the downhole pressure. Managed Pressure Drilling (MPD) systems are very often used when drilling HPHT wells (Rommetveit et al. 2003).

1.2.1 Drilling Mud Density

Drilling mud density varies along the well path in HPHT wells and is dependent upon temperature and pressure. The mud can expand, contract or be compressed. Verification of stable surface volume is a key factor in well control. Due to temperature variations the active surface volume might show a slight increase or decrease. Horner Plot is used in order to mitigate for temperature effects during flow checks (Rommetveit et al. 2003).

1.2.2 Drilling Mud Rheology

In conventional drilling, the rheological properties of the mud are independent of pressure and temperature. The rheological properties in HPHT wells need careful consideration when it comes to the effect of pressure and temperature due to the small margins between pore and fracture pressure. The rheological changes will cause the ECD to vary during drilling, which in worst case can lead to a fracture of the formation. These following factors affect the rheological properties (Rommetveit et al. 2003):

- Viscosity of the base fluid
- Concentration of the viscosifers
- Volume of the brine phase or synthetic/water ratio
- Loading and size distribution of weighting materials
- Quality of emulsion
- Wettability of solids
- Other additives such as fluid loss additives

1.2.3 Temperature effects

Mud temperature can change rapidly at a given depth in the well, dependent upon the drilling operation. When drilling pumps are switch on, the lower part of annulus is cooled by cold mud, while the upper part is heated with flowing hot mud. These volume changes due to temperature expansion can be interpreted as a "false kick" incident (Rommetveit et al. 2003).

1.2.4 Pressure effects

Pressure variations are increased in HPHT wells compared to conventional wells. Some of the reasons are (Rommetveit et al. 2003):

- The hydrostatic pressure will vary more when the mud density changes.
- There will occur frictional pressure changes, due to rheology variations in the wellbore.

- There will be higher frictional pressure. The rheology changes induce the flow regime to transition between laminar and turbulent flow.
- More critical surge and swab pressure.
- Mud rheology is dependent upon shear history. Broken gels cause a rapid peak in the bottom hole pressure during circulation.

1.2.5   Water based mud versus Oil based mud

An influx of gas/oil/condensate into the well will mix with the mud. Hydrocarbon gas solubility in the oil phase of the drilling mud is greater than in the water phase. In case of a kick the oil-based mud will behave differently than water-based mud. The mud volume will not increase until it is near the surface, because the gas influx will go into solution downhole under HPHT conditions and the gas will go out of solution and rapidly increase in volume close to surface.

Oil based mud is more preferable in these wells, because of the stability of the mud when it comes to rheology and fluid loss control (Rommetveit et al. 2003; Schlumberger 2016).

1.2.6   Ballooning effect

Ballooning is a phenomenon that occurs in HPHT wells. The mud leaks of slowly into the formation when the mud pumps are on while drilling. During connection, the bottom hole pressure decrease, due to loss of the friction in the annulus and the lost mud returns back to the wellbore and will very often be interpreted as a kick. It is also common that the returned mud bring additional formation gas to the wellbore. Once this is circulated back to surface it can be wrongly interpreted as increasing formation pressure.

1.2.7   Gas diffusion

Methane can diffuse from the formation through the mud filter cake and the mud-invaded zone into the wellbore when drilling with oil based mud. Gas diffusion can lead to loss of well control. The carrying capacity of the mud is also weakened, because of the dissolved gas in the mud (Rommetveit et al. 2003).

1.2.8 Annular pressure build up

During production in HPHT wells, there is a phenomenon called Annular Pressure Build-up (APB). High temperature hydrocarbons travel up from the pay sands through the production tubing and casing and the hydrocarbon flow heats up the well. If the annular space outside the production casing is closed, the temperature increase will lead to a pressure increase and in the worst-case make the casing string to collapse (Chief Counsels Report 2011; American Petroleum Institute 2013).

There are several methods to mitigate APB:

- One can avoid a sealed annulus by positioning the Top Of Cement (TOC) a sufficient depth below the previous casing shoe. Once the pressure reaches the formation fracture pressure at the shoe, the pressure will be bleed off inside the formation.
- Installing a compressible gas or fluid in the annulus expands the fluid and the compressible fluid volume will contract.
- Crushable material can be installed on the outside of the casing, e.g. syntactic foam. The material crushes as annulus fluid expands, which provide an additional volume for fluid expansion.
- Rupture disks in the casing provide protection for the casing string. The rupture disks are manufactured to fail for a given temperature.
- On wells with a surface wellhead, eventual pressure build up in the annulus pressures can be bleed off in a controlled manner. On subsea wells the annuluses are normally not accessible.

1.2.9 Cementing challenges

High pressure and high temperature influence the physical and chemical behaviour of cement material. This might lead to a difficult cement job. During the actual pumping operation of cement slurry, it is mainly restriction set to flow rates due to formation not supporting the actual ECD pumping heavy cement slurry through narrow annulus. Complications do not only appear during the cement job. Later, in the well life to the set cement sheath there can also arise challenges, due to changes in temperature and pressure (Radwan et al. 2011).

1.2.10 ECD

The HPHT wells have difficult drilling conditions. The wells often need to be redesigned as the well progresses. It is important to keep two factors within tolerable limits:

- Equivalent circulating density is the pressure that the formation see from above during circulation shown as a density value at the actual depth. This pressure is a sum of Equivalent Static Density (ESD) or hydrostatic pressure from the mud column plus added pressure required to overcome the friction forces in the annulus in order to bring the fluid back to surface. The ECD is biggest at bottom and will be reduced gradually higher up in the well.
- ESD is the sum of the hydrostatic pressure at different depths shown as an average density value at a given depth.

In planning the well, engineers will design a mud program to keep both ESD and ECD below the rock`s fracture gradient. Drillers monitor these parameters carefully as they work. Normally the measurement while drilling tool will give a continuous measurement of ECD while drilling and a ESD once every connections when the pumps are off.

The knowledge of accurate down hole temperature, and precise LOT and/or FIT test have an essential role in ECD management, as they will determine the efficiency by operating in the safe pressure window. Leak Off Test (LOT) and Formation Integrity Test (FIT) determine a formations fracture gradient. A LOT is performed by gradually

increasing the pressure on the formation and stops when the wellbore fluid starts to leak into the formation. A FIT is performed by gradually increasing the pressure to a predetermined value less than the prognosed fracture pressure (chief counsels report 2011).

2 Theory

2.1 General

The production casing design for HPHT wells require special considerations, during the planning phase, due to the high pressure and temperature experienced in these wells. The worst-case scenario for the production casing is a tubing leak, and it is therefore important to predict the accurate shut-in tubing pressure. Selection of yield materials is also important for the well design. Tri-axial stress analysis has to be implemented to ensure that the yield strength of the material is greater than the worst-case stress for the selected size/material combination. Use of sour service material is recommended in HPHT wells. Under extreme pressure conditions restricted yield materials may be required. To insure the integrity of the production casing system, the connection selected has to perform under extreme combined loads (Mudge 1983).

The selection of the production casing is one of the most important aspects during well planning. The other casings can be controlled by proper well control, while a production casing failure can be disastrous. The production casing serves as a backup protection in case of a tubing failure.

The next casing outside the production casing is not designed for the same loads as the tubing and production casing. An eventual exposure of full tubing pressure might lead to a leak that in worst-case can come to surface through the formation. When designing the production system one of the first steps are to predict all the loads that are acting on the string.

Most part of this chapter is retrieved from (Balayneh 2016) unless otherwise stated in the text.

2.2 Types of Production String Configurations

2.2.1 Full string production casing

The production casing provides isolation of production zones and will be exposed to formation pressures. If the tubing should leak, the production casing will be exposed to the same pressure. The casing can also be exposed to injection pressure from fracture jobs, pressure from gas lift and the injection of inhibitor oil (Petrowiki 2015a).

The production casing design criteria are:
- Be designed to maintain well integrity during all planned production and workover periods.
- Shall be designed and set to allow for further deepening of the hold if specified in the drilling program.

2.2.2 Liner

The liner is connected and normally anchored and sealed off to the bottom of the last casing string, and does not extend back to the wellhead (Petrowiki 2015a).

Production liner design criteria are:
- Shall isolate the productive zones if a production casing is not used, or if the production casing is set only to the top of the reservoir.
- All casing strings and liners exposed to production activities shall fulfil the production casing requirements with respect to well integrity during all phases of the productive life of the well.

2.2.3 Liner tieback string

The liner tieback string provides en extra pressure integrity at liner top to the wellhead. The production tieback string isolates the intermediate string from production loads (Petrowiki 2015a).

Tieback string design criteria are:

- The tieback casing has the same functional requirements as the production liner except that the axial load from testing is not present.
- The tieback casing is used to increase the well pressure integrity, often in connection with options such as flow testing of the well. Also it may be installed to increase the corrosion resistance if H_2S and CO_2 gases are present.
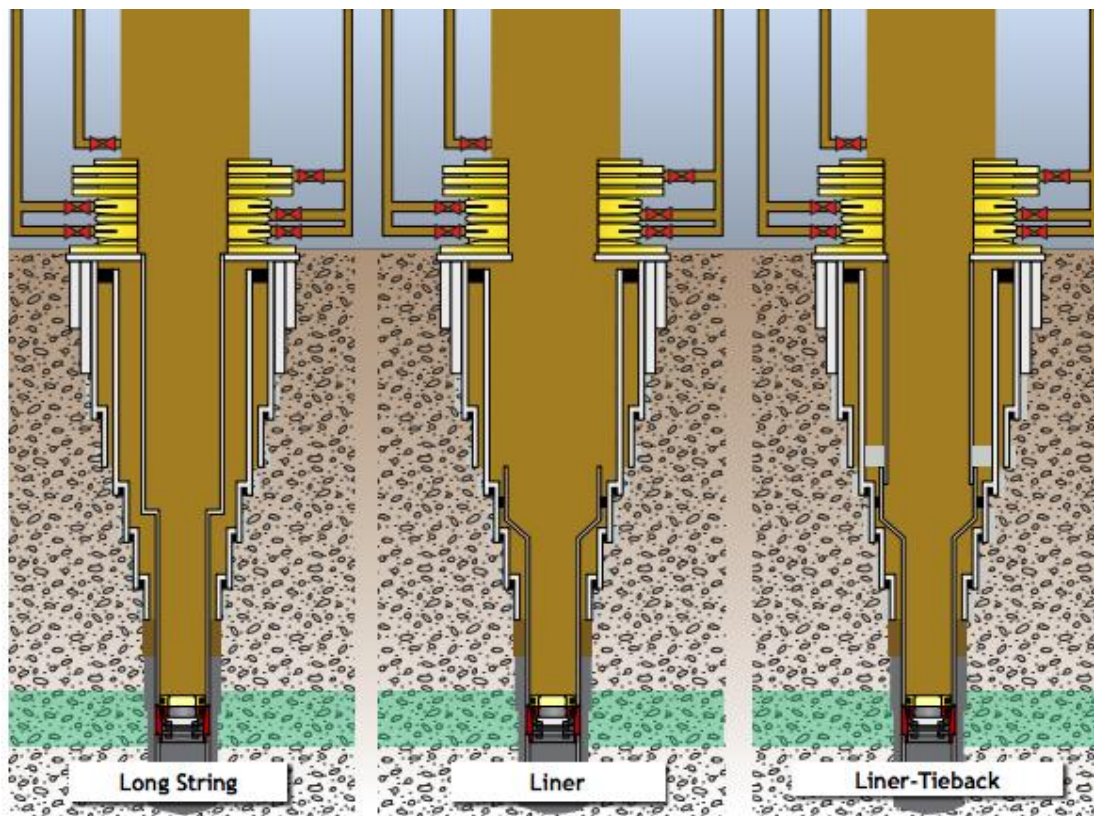
Figure 2 Production casing configurations (Chief Counsels Report 2011).

2.3 Casing Stress Design

The casing design has to meet the objectives for exploration drilling and completion. The well design can be complex when the production casing needs to be designed for the full life cycle of the well. The importance of stress analysis is to design a casing system that can withstand all operational loads that they are subjected to. In HPHT wells the casing is exposed to harsh conditions and complex loading and has to be designed to manage these conditions (Ayodele et al. 2013).

Stress fields have to be derived in order to design the safe operational limits. Consider a thick walled cylinder that is subjected to uniform pressure. These stresses are generated across the thickness of the cylinder in the radial, axial and the circumferential direction.

The stress distributions through the wall thickness are dependent on four conditions:

- Equilibrium equation.
- Compatibility relation.
- Constitutive stress- strain- temperature relation.
- Boundary conditions.

By combing these conditions, one can derive the stress fields across the wall thickness of the cylinder:

Radial stress:

$$S_r = \frac{p_a a^2 - p_b b^2}{b^2 - a^2} - \frac{a^2 b^2}{\left(b^2 - a^2\right) r^2}\left(p_a - p_b\right) + S_r\left(\mathrm{D}T\right)$$

<div align="right">Equation 1</div>

Hoop stress:

$$S_q = \frac{p_a a^2 - p_b b^2}{b^2 - a^2} + \frac{a^2 b^2}{\left(b^2 - a^2\right) r^2}\left(p_a . p_b\right) + S_q\left(DT\right)$$

<div align="right">**Equation 2**</div>

Axial stress:

Before deriving the axial stress equation two extra forces has to be defined: real force and effective force. The real force is the actual axial force in the pipe wall end and effective force is the axial force if pressure effects are neglected. The axial force applied to the tubing results in the axial stress:

$$S_a = \frac{F_a}{A} + \frac{p_a a^2 - p_b b^2}{b^2 - a^2} + S_z\left(DT\right)$$

<div align="right">**Equation 3**</div>

These equations are also approximated for thin walled cylinders. Almost all of the drilling pipes are of thin walled cylinders.

Shear stress:

Aadnøy derived for thin walled cylinders; the shear stress that is caused by the applied moment:

$$t = \frac{T}{2\rho r^2 t}$$

<div align="right">**Equation 4**</div>

2.4   Failure Criteria and Design Limits

2.4.1   Tresca failure criteria

Tresca failure criteria are developed from the maximum and minimum principal stress. The criteria states:

$$S_y = S_{max} - S_{min}$$

2.4.2   Von mises failure criteria

The Von Mises yield condition describes the yielding of steel under combined state of stress. The initial yield limit for a cylinder is based on the three principal stresses and the shear stress. The Von Mises failure criteria are given:

$$S_{VME} = \sqrt{\frac{1}{2}\left\{ \left(S_q - S_r\right)^2 + \left(S_r - S_a\right)^2 + \left(S_a - S_q\right)^2 \right\} + 3t^2}$$

The shear stress is caused by torque, i.e. when there is no torque the shear stress term are neglected from the equation. The yield limit is calculated by setting the Von Mises stress equal to the yield stress.

2.4.3 Equation of ellipse

The tri-axial stress design factor are given:

$$SF = \frac{S_y}{S_{VME}}$$

Where S_y is the minimum yield strength.

Four loads determine the combined stress limits in the tubing and casing. These loads are:

- Internal pressure
- External pressure
- Real axial force
- Torque

The pressure difference between the internal pressure and external pressure simplifies the calculation of the limits. A positive differential pressure represents burst condition, while a negative differential pressure represents collapse condition. The limits curve calculated from the Von Mises equation show when the tubing/casing will start yielding.

Aadnøy and Aasen developed a 3D stress analysis, which compute the burst and collapse pressure. When neglecting bending, torque and temperature effects the design factor is given:

$$SF = \frac{\sqrt{2}S_y}{\left[\left(S_a - S_h\right)^2 + \left(S_h - S_r\right)^2 + \left(S_r - S_a\right)^2\right]^{0.5}}$$

Inserting the equation for hoop stress and radial stress, assuming the maximum equivalent stress is obtained at the pipe inside surface letting $r = r_i$, one can obtain a dimensionless parameter by collection. The dimensionless parameters are then given:

$$x = (p_i + S_a)/S_y$$

$$y = b(p_i - p_o)/S_y$$

In terms of the dimensionless parameters, the design factor is given:

$$SF = \frac{1}{\left[x^2 - xy + y^2\right]^{0.5}} = \frac{S_y}{S_{VME}}$$

From above, one can then obtain the equation of ellipse:

$$y = \frac{x}{2} \pm \sqrt{\frac{1}{SF^2} - \frac{3}{4}x^2}$$

Where the plus sign represent burst condition, and the negative sign represent collapse condition. The ellipse in 2D plane with the different design factors is shown below.
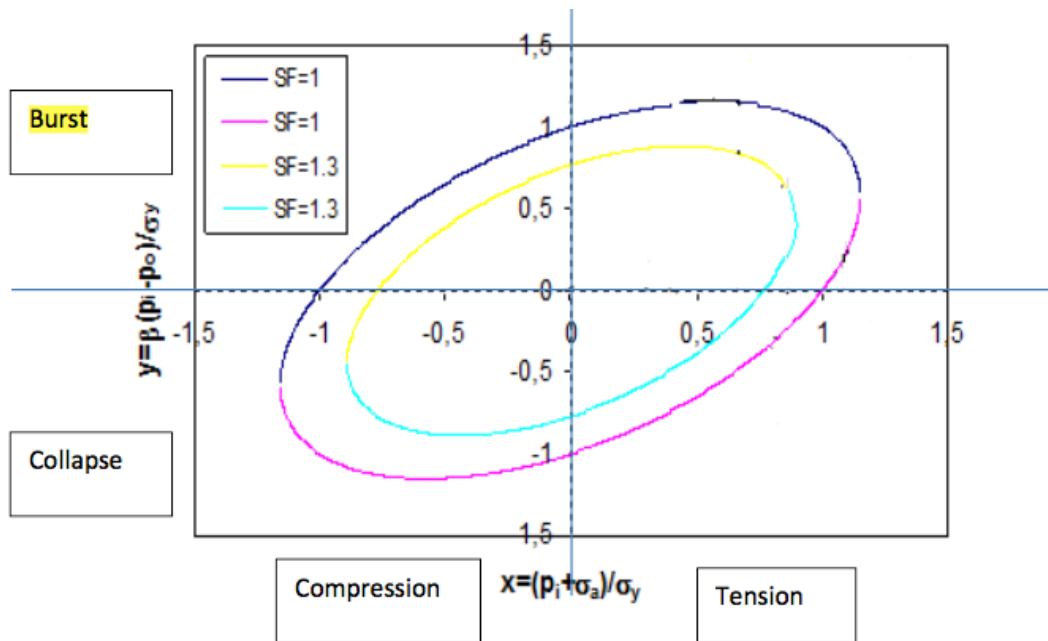
Figure 3 Illustration of the ellipse for different design factors (Balayneh 2016).

2.5 Design Loads for Production Casing

The production casing should be designed to withstand all the anticipated loads it is exposed to during it`s intended service life. The strength of the casing has to be greater than the particular load type. The design formula state:

$$Strength \geq Load$$

<div align="right">**Equation 13**</div>

The challenge is to appropriately analyse the load case of the equation. Rewriting of the equation gives the degree of which strength is greater than the load. The degree is defined as the safety factor, by the following equation:

$$Factor\ of\ Safety = \frac{Strength}{Load}$$

<div align="right">**Equation 14**</div>

Strength is calculated from strength defining properties of the pipe, which are dimension and material properties. These properties combined with an appropriated design model estimate the strength or resistance to a given type of load. These strength-defining properties could be yield strength, pipe diameter, tensile strength and material toughness.

During the productive life of the well for the production casing, Burst and collapse load must be accounted for. The loads on the production casing occur because of the differential pressure from unanticipated failure of the equipment and pressure and temperature changes from the producing hydrocarbons. A successful casing design is established when the loads are properly evaluated and the factor of safety is high enough (Lewis 2011).

2.5.1 Burst Load

Several assumptions have to be considered for the burst load design for the production casing. These assumptions are (Prentice 1970):

- The density of the packer fluid is equal to the weight of the mud in the annular space behind the casing.
- Tubing leak near the surface, which can lead to the surface tubing pressure is introduced as a burst load over the entire length for the production casing.

For the production casing, the burst load condition is tubing leak. Tubing leak is an accidental load condition that can occur at any place in the production tubing, during well testing or production. If a leak occurs in the production tubing, one of the two mechanical barriers fail and the well must be shut-in and repaired. Pressure in the A-annulus occurs when the well is shut-in. A-annulus is the annulus between the production tubing and production casing. Differential pressure arises between the production tubing and the production casing, which create a burst load on the casing. Considerations have to be taken when designing the density of the packer fluid in the A-annulus to calculate the burst load. This is the critical burst load case; the casing must be strong enough to withstand this load (Lewis 2011).

2.5.2 Collapse Load

The collapse design takes no consideration for backup fluid, because of the possibility of tubing leaks, artificial lift and plugged perforations. The design of the string is assumed to be dry inside. The collapse load is supplied by the hydrostatic pressure of the heaviest mud weight of the string is run in. The design factor is applied to this load (Prentice 1970).

Full evacuation:

This design load model are used in severely depleted reservoirs or reservoirs with a large drawdown, because of low permeability or plugged perforations. The model assumes that the internal pressure is zero and the external pressure is the mud gradient from surface to casing bottom (Devon Energy Corporation).

Abandonment collapse:

At the end of the wells life, there is a load condition called abandonment collapse. The well has been producing for a long time and the reservoir pressure has decreased considerably since the completion. There is no longer a high-pressure flow from the reservoir to the surface, meaning that the pressure on the outside can exceed the internal pressure. Leading to packer failure and packer fluid can leak into the reservoir. More pressure is exerted on the outside than the inside of the production casing, because the reservoir pressure balances the packer fluid hydrostatic height. The load condition result in a collapse load on the production casing and has to be accounted for in the design (Lewis 2011).

2.6 Well Cementing

The well cementing job is a very critical job during a well operation. The cements main task is to fill the annular space between the outside of the casing and the formation. The cement act as a protection for the casing against corrosion and it seals off the annular space, which prevents gases and fluids to flow up or down the annular space. The primary function with the cement job is to achieve zonal isolation between the casing and formation.

Most part of section 2.5 is retrieved from (Chief Counsels Report 2011), unless otherwise stated.

2.6.1 Fundamentals of well cementing

Well cementing consist of two principal operations—primary cementing and remedial cementing. The highest chance to get a good cement job is always in the primary one——it is a good investment to spend extra time and money on this one.

Primary cementing: The cement sheath is placed in the annulus between casing and formation, which is a critical process. The cement sheath shall provide a hydraulic seal to establish zonal isolation. The fluid communication is prevented between producing zones and the fluid cannot escape to the surface. Main task for the cement sheath is to support and protect the steel casing against corrosion. If a failure occur with the cement sheath, the well`s ability to reach its full producing potential is limited.

Remedial cementing: The engineers inject cements into strategic well locations for various purposes during well repair and well abandonment. Remedial cementing is executed after primary cementing if necessary.

The most used method during primary cementing is a two-plug cement placement. The drill pipe is removed, while the borehole is filled with drilling fluid. Then a casing string is lowered to the bottom of the well. The bottom end of the casing string is protected by a guide shoe or float shoe, which are tapered. Tapered is a bullet-nosed device that guides the casing towards the centre of the hole, to reduce contact with

rough edges or washouts. All shoes are equipped with one or two check valves to prevent reverse flow and U-tubing of drilling fluids from the annulus into the casing once the cement slurry is in place in the annulus outside. The density of cement slurry is normally higher than the drilling mud and without the check valves; the slurry would balance back into the casing.

As the casing in run into the well, the casing is filled with drilling fluid, since the check valve stops any automatic filling from the bottom.
The objectives with primary cementing are to remove drilling fluid from the casing and the borehole, place cement slurry in the annulus and to fill the casing with a displacement fluid. The displacement fluid is normally the mud used for drilling.

Cement slurry and drilling fluids are usually chemically incompatible, which may result in a thickened or gelled mass at the interface. This gelled mass is difficult to remove from the wellbore and can prevent placement of a uniform cement sheath in the annulus. Chemical and physical means to maintain fluid separation are employed as a solution, where chemical washes and spacer fluids can be pumped after the drilling fluid and prior to the cement slurry. The chemical washer and spacer fluids can clean the casing and formation surfaces, which improves the cement bonding.

Wiper plugs are elastomeric devices that provide a physical barrier between fluids pumped inside the casing. There is a bottom plug that separates the cement slurry from the drilling fluid, while a top plug separates the cement slurry from the displacement fluid. The bottom plug is employed with a membrane that ruptures when landing at the bottom of the casing string, which establishes a pathway for the cement slurry into the annulus. The top plug is not employed with a membrane; the hydraulic communication is separated between the casing interior and the annulus, while landing on top of the bottom plug. A proper landing of the top plug will allow for pressure testing of the casing string immediately after pumping the cement slurry and before the setting of the cement.

When the cement operation is completed, the cement needs to cure, set and develop strength. This is known as waiting on cement. If the cement job is performed successfully and bonding is established further drilling can carry on.

Top plug

Solid core

Bottom plug

Rupture disk

Hollow core
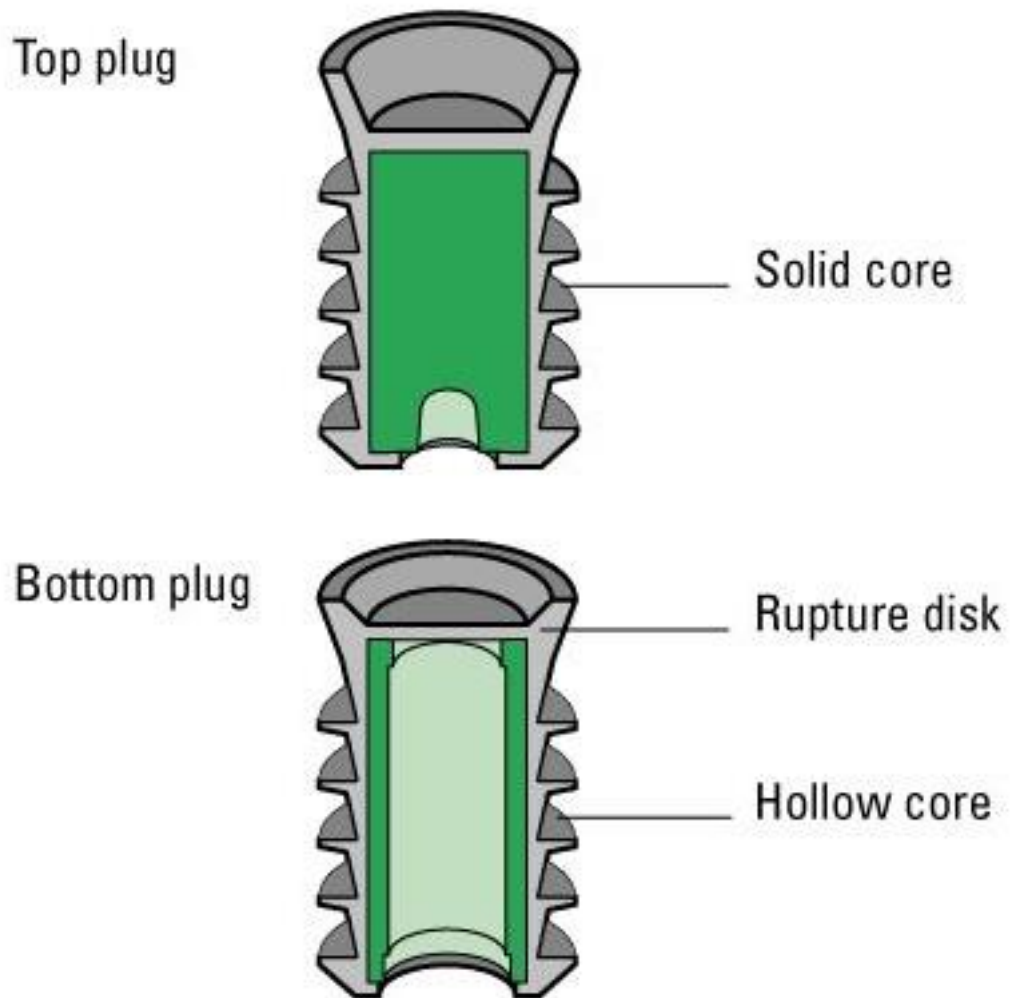
Figure 4 Wiper plug (Schlumberger).

2.6.2 Bottums up

Under ideal conditions, it is preferred to circulate enough drilling mud through the casing after landing it to achieve full bottoms up. This means that the mud at well bottom will travel back to the surface and any remaining gas is circulated out before cementing the casing string. Circulating cold mud from surface will also decrease the downhole temperature in the well during the cement job. This is in some cases an advantage for long circulation periods before a cement job.
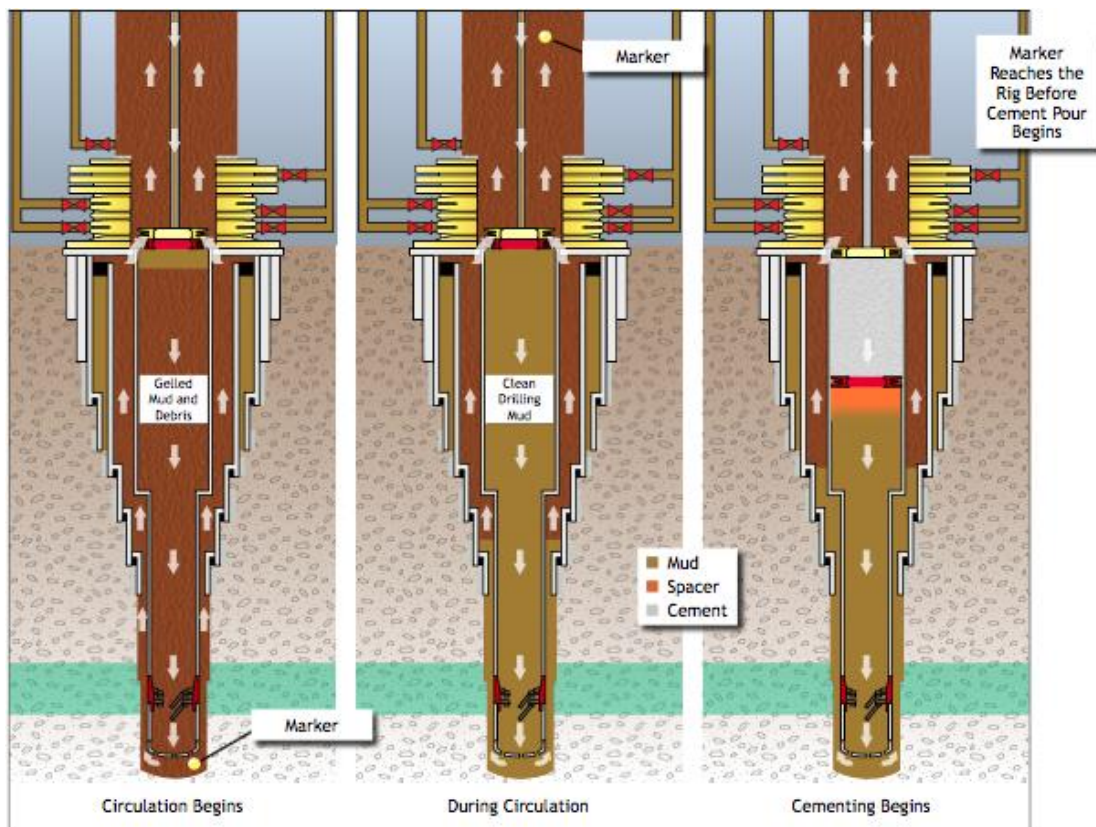
Figure 5 Full bottoms up (Chief Counsels Report 2011).

2.6.3 Portland cement

Almost every well cementing operation uses Portland cement. Portland cement consists of anhydrous calcium silicate and calcium aluminate compounds that hydrate when mixed with water. The calcium silicate hydrates provide low strength and low permeability, which is required to achieve zonal isolation.

The Portland cement is exposed to a wide temperature range. The cement manufactures produce special versions of Portland cement for the use in well

construction. To adjust the cement performance, over 100 cement additives are available, such that the cement formulation can be customized for a particular well environment. The objective is to formulate cement that is pumpable for a time sufficient period, during placement in the annulus. The cement needs to develop strength within a few hours after placement and remain durable throughout the wells lifetime.

Additives are classified according to the functions they perform:

- Accelerators reduce the cement setting time and increase the rate of compressive strength development.
- Retarders delay the setting time and increase the time when cement slurry is pumpable.
- Extenders decrease cement slurry density and reduce the amount of cement per unit volume of set product.
- Weighting agents increase the density of cement.
- Fluid loss control agents manage leakage of water from the cement slurry into porous formations. Thereby sustain the cement slurry properties.
- Loss circulation control agents limit flow of cement slurry from wellbore into weak formations. Also they ensure that the cement slurry is able to fill the entire annular space.
- Dispersants decrease the viscosity of the cement slurry, which generates lower pumping pressure during placement.
- Specialty additives include antifoam agents, fibers and flexible particles.

2.6.4 Logging and Hydraulic testing

Prior to installing the production casing and performing the final cement job the well engineers need to collect information from the drilled section. Some of the information's are collected while drilling with Logging While Drilling tools (LWD). Separate runs with electrical logging tools will collect additional information from the wellbore. Logging the wellbore is a process where the well engineers examine the

open section of the wellbore with the use of logging tools that transmit electric, sonic and radiologic signals to measure the formation and the fluids in the wellbore. After the cement job electrical logging tools can be run inside the casing in order to confirm the quality and height of the cement job. The evaluation of the cement includes hydraulic pressure testing.

The well logging methods include a Cement Bond Log (CBL) and an Ultra-Sonic Logging tool (ULS). The CBL is a logging tool that reflects amplitudes of an acoustic signal transmitted inside the casing and it measures the cement casing bond integrity, witch is proportional to the attenuation of the reflected signal.

ULS measure the qualitative insight of the casing, cement sheath and the formation. The ULS transmit ultrasonic pulse, which cause the casing to resonate.

The most common method for hydraulic testing is pressure testing. First a casing pressure test is performed to verify the mechanical integrity of the string, and then the casing shoe is drilled out. Pressure integrity test is performed afterwards. The internal casing pressure is increased until it exceeds the pressure that will be applied in the next drilling phase. The cement seal is confirmed successful if there is no leakage (Schlumberger 2012).
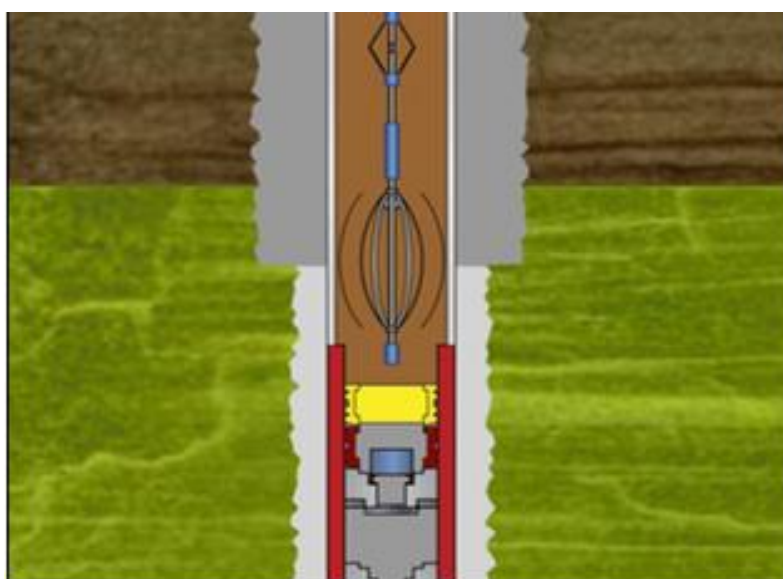
Figure 6 Cement Bond Log tool (Chief Counsels report 2011).

2.6.5   Squeeze cementing

If the logging tools indicate that the cement job is poor including poor cement bonding or communication between zones, a cementing technique called squeeze cementing is implemented to establish zonal isolation. Squeeze cementing is to perforate the casing at the defective interval and cement slurry is squeezed through the perforations and into the annulus to fill the voids. Squeeze cementing can also be an effective technique for repairing casing leaks (Schlumberger 2012).
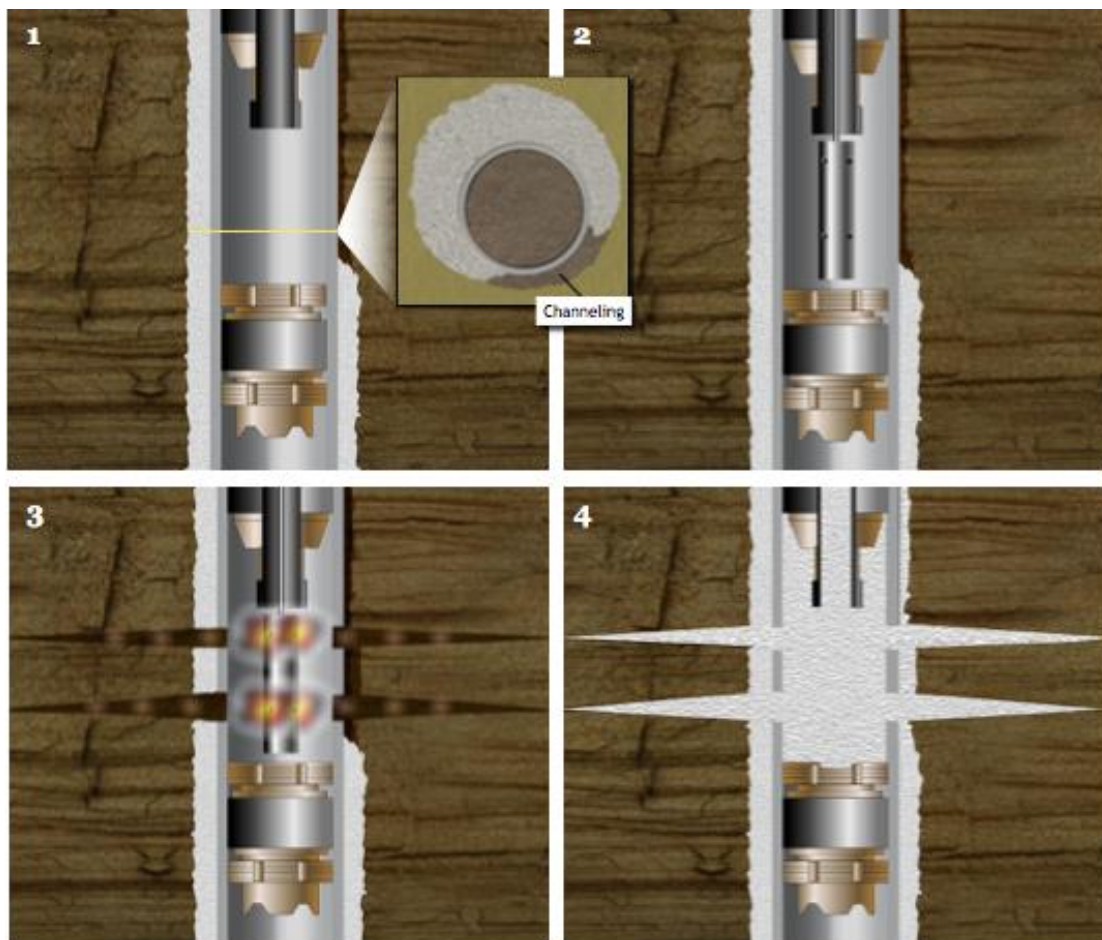
Figure 7 Squeeze cementing (Chief Counsels Report 2011).

2.6.6   Centralizers

When the logging process is completed, the production casing can be set in place. During the process of installing the production casing, there is a need to use centralizers. Centralizers are a device to keep the casing or liner in the center of the wellbore. The centralizers help ensure efficient placement of cement sheath around the casing string. If the casing string is not centered, the wider annular space can be a path of least resistance. Cement can tend to flow up only at one side creating a non-cemented channel at the opposite side. This is called channeling. Centralizers prevent the casing form sticking while running in hole.

2.6.7   Plug cementing

Plug cementing is another remedial cementing technique performed at the end of a wells productive life. The casing interior is filled with cement at various depths, which prevents interzonal communication and fluid migration into underground freshwater sources. The main objective is to restore natural integrity of the formations that were disrupted by drilling (Schlumberger 2012).

2.6.8   NORSOK D-010 Requirements

According to NORSOK D-010 the Cement height in casing annulus along hole (TOC) shall be 100 meters above a casing shoe, where the cement column in consecutive operations is pressure tested / the casing shoe is drilled out.

Also the cement height for casing through hydrocarbon bearing formations shall be defined based on requirements for zonal isolation. The cement should cover potential cross-flow interval between different reservoir zones.

For cemented casing strings which are not drilled out, the height above a point of potential inflow/leakage point/ permeable formation with hydrocarbons shall be 200 meters, or to previous casing shoe, whichever is less.

2.7 Barriers

The rig personnel must ensure that hydrocarbons do not migrate from the reservoir into the well during drilling, casing and completion of the well. Barriers must be created and maintained inside the well to maintain well control. The barriers control the subsurface pressure and prevent flow of hydrocarbon. The rig personnel employ operational barriers during drilling, while some barriers are part of the well design (Chief Counsels Report 2011).

2.7.1 Functional requirement of barriers

The Norwegian Petroleum Industry defines in the NORSOK D-010 Standard the functional requirement for barriers. The standard state that there shall be one well barrier in place if there are (Khalief 2016):

- Undesirable cross flow between formation zones.
- Normally pressured formation with no hydrocarbon and no potential to flow to surface.
- Abnormally pressured hydrocarbon formation with no potential to flow to surface.

Also the standard state that there shall be two well barriers in place if there are:

- Hydrocarbon bearing formations.
- Abnormally pressured formation with potential to flow to surface.

Primary barriers

The key operational barrier is the drilling mud. Hydrocarbons cannot flow into the well, if the column of drilling mud exerts pressure on the formation that exceeds the pore pressure. The well is overbalanced if the mud pressure exceeds the pore pressure and if the pore pressure exceeds the mud pressure, the well is underbalanced. If the well is underbalanced the mud pressure is no longer sufficient on its own to prevent hydrocarbon flow.

Barriers to prevent flow can also be physical components in the well. One of these barriers are the casing combined with the cement in the bottom of the well. The production casing and the cement in the annular space should prevent hydrocarbons to flow up the annular space or up the inside of the well.

To increase the redundancy of the system, rig personnel install additional barriers inside the well. These additional barriers can be: (Chief Counsels Report 2011):

- Cement can be pumped inside the final casing string to create cement plugs at different depth inside the well.
- Metal or plastic mechanical plugs can be installed inside the well. Some can be retrieved later in the drilling process and others can be drilled out when necessary.

Secondary barriers

The secondary barrier is used if the primary barrier fails. The Blow Out Preventer (BOP) stack is a secondary barrier. The BOP is installed with rams, which can close in the well. The hydrocarbon flow is then prevented to flow up the well into the riser. The pressure rating for the BOP must always be higher than the max anticipated surface pressure with a well full of gas.
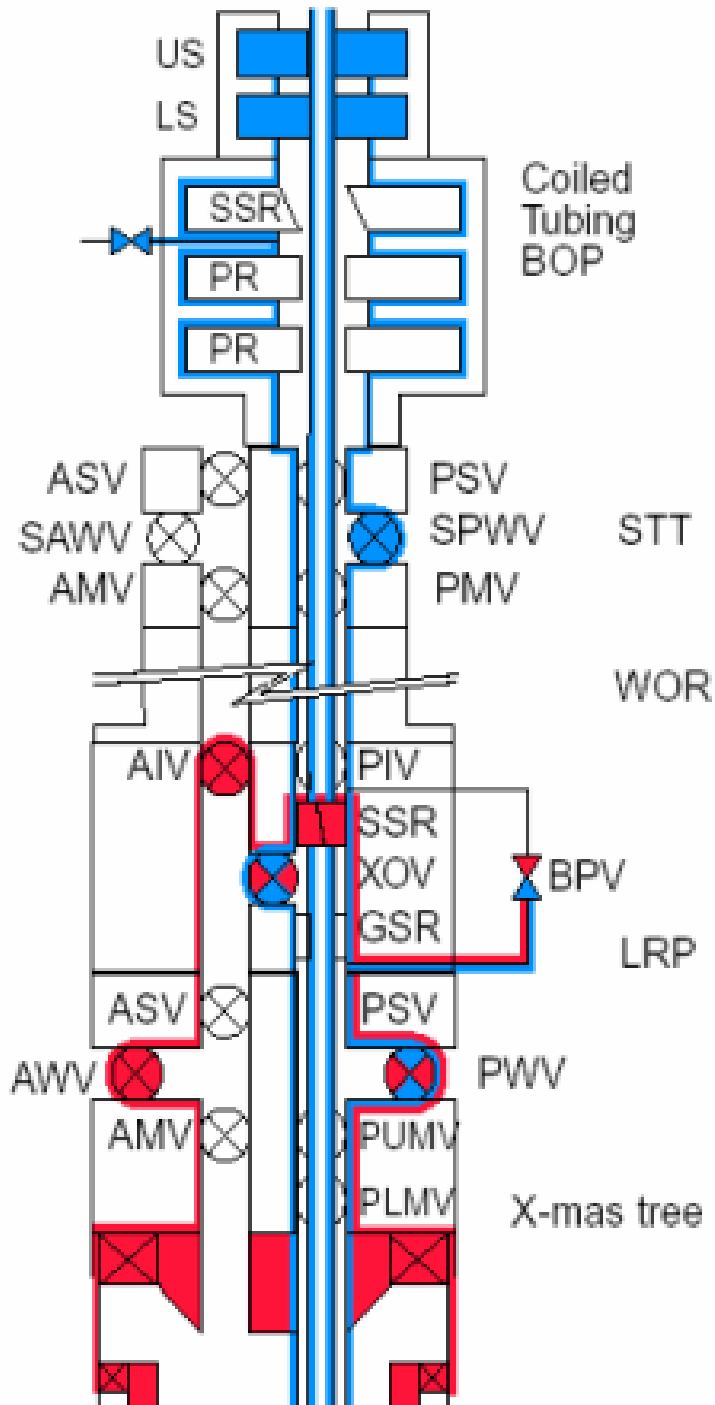
Figure 8 Primary and secondary barriers (NORSOK D-010 2013).

The blue represents primary barriers, which are the first to prevent flow from the well. The red represents secondary barriers, which are the second to prevent flow from a source.

3 Full String Casing Design

3.1 General

The main function for the production casing is to achieve zonal isolation. To obtain a good isolation, the cement operation needs to be executed successfully. The long string casing is landed in the wellhead prior to cementing with sufficient flow area through the casing hanger. When selecting a long string casing as the production casing there has to assessed considerations for the casing annular barrier. These following aspects are (American Petroleum Institute 2013):

- There should be two verifiable physical barriers: annular cement and casing hanger seal.
- There should be an addition of supplemental annular barriers: swellable packers or inflatable packers in the annulus.
- Slurry design, placement of cement and verification of cement.
- Short transition time, anti-gas migration properties, fluid loss and rheology.
- Lost circulation during cementing from ECD, because of long small annular clearances.
- Low displacement rates lead to poor displacement efficiency.
- Wells that experience losses or have poor mud/cement displacement efficiency can require increased levels of evaluation to confirm the cement barrier.
- Primary cement barrier quality
- The potential for annular gas migration, which result in additional casing and wellhead loads.
- The effect of thermal cooling of the mud. The hydrostatic pressure can change prior to the cement is set.
- Mitigation options
- Casing hangar lockdown requirements
- Exposure time with non-shearable items across the BOP stack when selecting the full string option.

3.2 Cementing the Long Casing String

The long casing string is usually cemented by the single-stage method, where cement slurry is pumped through the casing shoe with the use of top and bottom plugs. The single-stage cementing method will be outlined in the case study from Martin Linge.

Multistage cementing operation is also a cementing technique for the long casing string. The multistage cementing technique is used in wells with critical fracture gradients. The operation allows cementing two or more single casing string separately. The lower section is first cemented and cement flows through the casing string into open holes that are coupled to the casing string. The section above the coupling is cemented and the operation is repeated several times at various locations up the casing string. The multistage cementing technique provides (Lyons et al. 2005):

- Reduced pumping pressure of the cement pumping equipment.
- Reduced hydrostatic pressure on weak formations, which prevent fracture.
- Selected formations that can be cemented.
- An entire length of a long casing string that can be cemented.
- An effectively cementing of the casing shoe of the previous casing to the new string.
- Reduced cement contamination.

There are three methods for multi-stage cementing that need to be described. These methods are:

- Regular two-stage cementing
- Continuous two-stage cementing
- Regular three-stage cementing

3.2.1   Regular two-stage cementing

In addition to the regular casing equipment, cementing collar and plugs are implemented to the operation. The collar is located at the mid point of the casing string or at the place where the upper cementing is performed and has the feature of ports, which can open and close into the annulus by pressure operating sleeves. The difference between a conventional single-stage cementing operations and a two-stage cementing operation is that the wiper plug is generally not run into the casing string prior to the spacer and cement slurry. The cementing stage collar is first sealed off, following with the first stage plug released after the pumping of spacer and cement slurry. The plug is pumped down to the float collar at the bottom of the casing string, while using drilling mud as displacement fluid. When the first plug is landed onto the float collar, a pressure rise occurs at the pump. The plug seals off the float collar to prevent further flow throughout the collar. The opening bomb is drop the to the lower seal of the cementing collar. When the port is opened up, circulation is continued until there is appropriate drilling mud in the well.

The second-stage cementing procedure mix and pump cement slurry into the well, without wipers plug. The cement slurry passes through the float ports into the upper section of the annulus. The closing plug releases and displaces the cementing collar with drilling mud. A pressure cause the retaining pins in the upper sleeves to shear, which force the sleeve downward to close the ports in the cementing collar (Lyons et al. 2005).
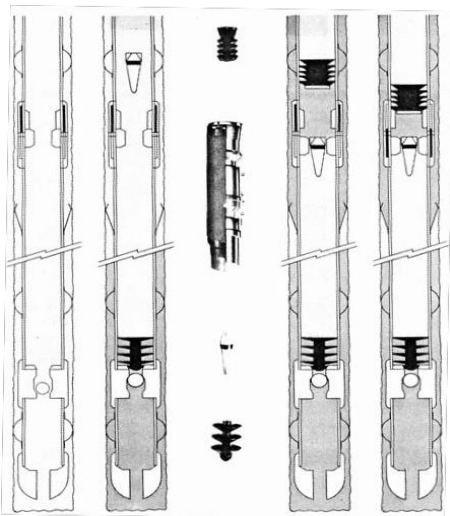
Figure 9 Regular two-stage cementing (Lyons et al. 2005).

3.2.2 Continuous two-stage cementing

Cement is first mixed and displaced to the lower and upper section of the annulus in sequence, without stopping to wait for an opening bomb to actuate the cementing collar. The slurry is pumped down the well with a wiper plug released behind it and cement slurry is displaced out of the casing with drilling mud filled in the inside of the casing string from the float collar at the bottom of the casing string to the cementing collar. When a bypass insert is installed, fluid is allowed to pass through the wiper plug and float collar after the plug is landed. The opening plug is pumped immediately behind the volume of drilling mud. The second-stage spacer and cement slurry are located behind the opening plug. The ports are opened into the annulus and the cement slurry plug is run into the well. This plug with additional hydraulic pressure closes the ports in the cementing collar (Lyons et al. 2005).
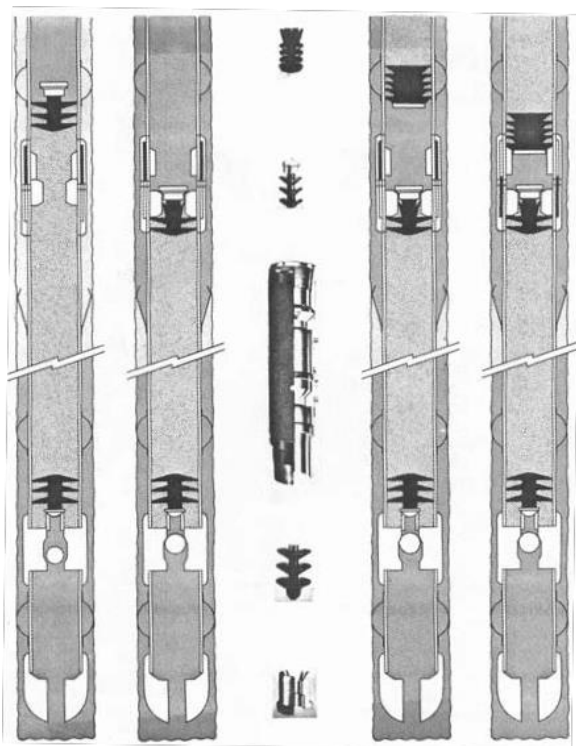
Figure 10 Continuous two-stage cementing (Lyons et al. 2005).

3.2.3 Three- stage cementing

This procedure is almost the same as with the regular two-stage cementing procedure. However, the three-stage cementing procedure provides that each stage is carried out in sequence. First cementing the lower annulus section, then the middle annulus section and at last the top annulus section. Each stage of cement is allowed to be set, if the lower stage of cement do not rise above the cementing collar of the next stage (Lyons et al. 2005).

3.2.4 Challenges during cementing

Cementing the long casing string can be a difficult operation. There are some critical factors that need to be assessed prior to the cement operation. These factors are:

- Centralization
- Mud removal/pump rate
- Channeling
- Bonding
- Volume
- Back-pressure

The circulation rate prior to cementing the long casing string can be insufficient to clean the annulus. This can happen if there are too low pump rate or if there is a risk of loosing the "Loss circulation material barrier" and also if it did not completely circulate "bottoms up". Hydrocarbons can be trapped within the mud, and there can be inadequately conditioned mud.

A common problem with the long string casing cementing is contamination of the cement by the drilling fluid that is displaced. The strength of the cement can be degraded if other fluids contaminate the slurry. Optimization of the rheological properties of the fluid is essential for obtaining a successful cement job.

Cement needs to travel through a larger surface area compared to a liner string. There is a higher risk for the cement to be exposed to mud and cuttings in the casing. If the

production string is tapered the risks is even higher, due to the wiper plugs cannot reliably wipe clean.

The pipe also cannot rotate during the cement operation, which reduces the mud-to-mud displacement efficiency in the annulus.

When it is difficult to remediate at the bottom a squeeze job is required, which is a very complicated and time-consuming operation (Chief counsels report 2011).

4 Liner and Tieback String Design

Most part of chapter 4 is retrieved from (American petroleum Institute 2013), if not otherwise stated.

4.1 General

In HPHT wells it is common to use a combination of liner with a tieback string as production casing. The tieback string extends the production liner back to the wellhead. Liner with tieback string provides a pressure-containing system from the base of the liner to the top of the tieback casing (Yakely 2015).

The combination of a liner and tieback string is often used in gas-exposed intervals, which are experiencing severe lost circulation or in intervals where hole conditions prevent the casing hanger from landing in the wellhead. The liner allows the casing to be hung at any depth if the string does not reach the bottom and the time while the pipe rams can be closed on the drill pipe while running the string during liner installation is increased—well control is enhanced.

The selection of liner as a production string is based on the expected pressures and the combined loads in the wellbore. Liner hangars can provide reduced burst and collapse ratings, compared to tubulars with high-strength. Hanging the liner in the next string can be considered if there are reduced pressure ratings. A tieback receptacle can be placed below the hangar to increase the system rating.

The liner combined with the tieback string increase the complexity of the well construction and has to consider the following:

- Tieback stem and liner Polished Bore Receptacle (PBR) interface design.
- Installation space-out engages the tieback stem seals when the casing hangar is landed in the wellhead.
- Tieback anchoring method to limit seal movement during the well`s life cycle.
- An additional trapped annulus subject to APB loads.

If the liner is well cemented within the production casing, performance of the liner hanger and reliability of the annular pressure barrier is enhanced. The system integrity is determined by several factors when there is no cement in the overlap. These factors are:

- The elastomer seal integrity.
- Capacity of slips and hold-down mechanism.
- Capacity of the various machined components.

The capability of the liner hangar is limited by the tight clearance in the well architecture design, which necessitate setting it higher in a larger string.

4.1.1   Liner Hangers

The liner hangers provide the support of the weight of a liner in the casing. Also they provide a barrier against annular flow, when they are combined with an external Packer. The packer element isolates the annulus above and below the packer.

Production liners hung off inside production casing
If the liner is well cemented within the production casing, performance of the liner hanger and reliability of the annular pressure barrier is enhanced. The system integrity is determined by several factors when there is no cement in the overlap. These factors are:

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- Capacity of slips and hold-down mechanism.
- Capacity of the various machined components.

The capability of the liner hangar is limited by the tight clearance in the well architecture design, which necessitate setting it higher in a larger string.

Production liners hung off inside drilling casings

The production liner tieback configuration has additional annular barriers compared to the liner alone. These barriers include tieback cement and the tieback wellhead seal assembly. Changes in pressure and thermal loads prevent the tieback seal from moving, during the cementing of the tieback. The seal reliability is also improved.

Liner hanger configurations

To contain and control the produced fluids over the life cycle of the well, the liner hangars should provide long-term reliability. Considerations should be taken to the effect of full shut-in load on a column of packer fluid and also collapse loads from APB for the production case.

Liner Hangar configurations are given:

- Liner hangar material selection is similar to the tubulars above and below the liner hangar system.

- H2S service applications.

- CRA materials may be considered if the liner hangar is set in a wetted flow path for water injection or CO2 service.

- The liner hangars should be designed for the anticipated pressure and combined loads.

- Burst and collapse ratings should be relative to the ratings of the outer casing and liner compared to the design requirements.

- In close tolerance liner hangar configurations; the hangar design needs to meet the difficult burst and collapse ratings for the used high strength tubular. The reliability for these applications is increased when the PBR is positioned below the hangar body to isolate the hangar body when tying it back to the casing. Considerations has to be taken when setting the liner hangar in the next larger string, which also allows sufficient clearance to design the PBR with higher burst and collapse capability than in close tolerance application.

- Collapse loads and APB on tieback sleeves and PBR`s when tied back to the wellhead.

If the packer sealing elements on liner hangers and liner top packers are used within their design limits, service conditions and are installed successfully they are considered reliable.

Internal ports and pistons with sealing areas are used to set the liner hangar. These ports and seals are exposed to wellbore fluids if they are not isolated properly. Resulting in reduction in reliability of the hangar packer as a barrier, in which it provides another pressure containment failure path.

Using a liner tieback system with the PBR below the liner hangar or a liner hangar system without internal ports, eliminate the probability of having the internal ports and sealing areas as a possible leak path

The slip design limit the pressure and tensile load rating of the hangar system. The pressure that can be applied to the LTP is also limited by slip loading capacity. The slip capacity ratings are associated with the weight and grade of the outer casing along with the presence of external support in the adjacent casing annulus. The total load capacity increases with cemented casing. The cemented casing also provides backup to slip loading.

4.1.2   Seals and seal stem

The seals installed in the tieback receptacle should have long term reliability if they are expose to production fluid to contain and control the produced fluids over the life cycle of the well. The seal materials are selected based upon well conditions and compatibility with well fluids. Seal reliability is reduced when movement from changing thermal or pressure loads. Cementing the tieback can prevent these movements. The tieback can create a trapped annulus that may require mitigation of APB. The collapse rating can increase by positioning the seal stem in the PBR. The exposed length of unsupported PBR is reduced. A tieback stem in a PBR add complexity to the system, as with the combination of a tieback and liner.

4.1.3 Surge pressure when tripping

Surge pressure during running in hole can generate losses and well control problems. Running pipe or casing into the wellbore is an exceptional flow case that must be studied in each case. The pipe that is moved into the wellbore displaces fluid, which generates pressures called surge pressures. When pipe is pulled from the well it generates negative pressure called swab pressures.

In most wells surge pressures are not critical, due to proper casing design and mud program leave large enough margins between fracture pressure and formation-fluid pressure. However running low clearance liner into HPHT wells is prone to large surge pressures. The low clearance liner produces large fluid friction effects. Fluid swabbing behind the liner will occur, because the fluid ahead of the liner cannot easily penetrate the low clearance annulus, while large surge pressures are produced ahead of the liner (Petrowiki 2015b; Mitchell 2004).

4.2 Cementing Liner

Placing and cementing the liner can be a difficult operation to perform. Therefore design and planning must be executed carefully to ensure a seal between the liner and the previous casing. The liner is run into the well on the drill pipe and the cementing operation is carried out through the same drill pipe. The liner hanger is the key element when running and cementing liner.

The liner assembly is general made up with the following components:

- Float shoe: a combination of a guide shoe and a float valve usually placed at the bottom of the liner.
- Landing collar: short sub that is situated inside the casing string. Provides a seat for the casing string.
- Liner: the casing string, which is used to case off the open hole without bringing the end of the string to the surface.
- Liner Hanger: Installed on top of the liner string. The top of the liner hanger makes up to the drill pipe on which the entire liner assembly is lowered into the well. Can either be mechanically and hydraulically actuated (Lyons et al. 2005).
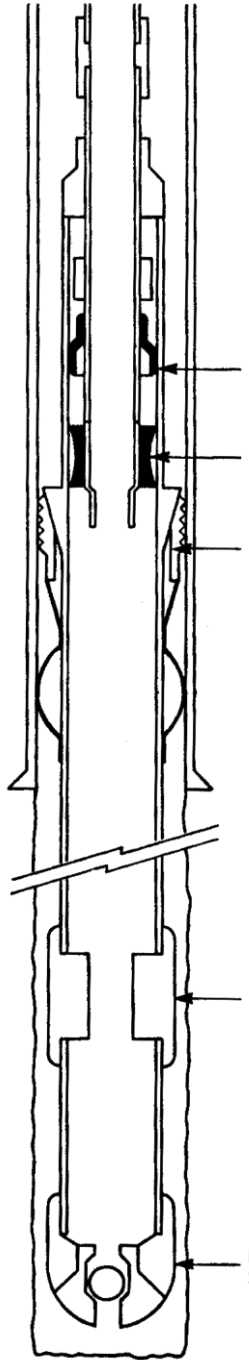
Figure 11 Liner Assembly (Lyons et al. 2005).

The casing joints are placed in the well as with conventional cementing operations. The liner hanger is made up to the top of the liner, while top of the liner hanger is made up to drill pipe. The whole liner assembly is lowered into the well at the desirable location and mud circulation can carry out. The circulation allow

conditioning of the drilling mud prior to the cementing operation and ensure that circulation is achievable before the liner is hung off and cemented.

Next procedure is to set the liner hanger, while the liner hanger upper part (setting tool) is released. The setting tool is raised to ensure that it can be released from the lower part of the liner hanger and the liner. The setting tool is also lowered to ensure that there is a tight seal with the lower portion of the liner hanger.

A liner cementing head with a pump-down plug is made up to the drill pipe at the surface. The spacer and cement slurry is pumped into the cementing head. The pump-down head make sure that the cement slurry is separated from the drilling mud when it is released. The drilling mud displaces the pump-down plug to the liner hanger. When the pump-down plug passes through the liner hanger it is latch into a wiper plug. The wiper plug coupled with the pump-down plug plus additional surface pressure is released from the liner hanger and is moving downward. The wiper plug and pump-down plug seats on the landing collar or on the float collar. A pressure rise can indicate that there is cement in place behind the liner.

The setting tool is released from the lower part of the liner hanger when the cement slurry is pumped successfully. The liner cementing head is then removed from the drill pipe and the setting tool is raised slightly to reverse circulate the excess cement from the liner hanger area. The reverse circulation procedure is performed immediately after the cement operation. If not there can be a risk of cement slurry setting, which can lead to drilling problems. The determination of the excess cement is thereby very important to the cement design. If there are small amounts of excess cement the cement seal can be contaminated with drilling mud, while too much excess cement are difficult to remove.

A special feature with the liner hanger is that after cementing operation the upper part of the liner hanger is retrievable, which allows for the residual cement above the liner hanger to be cleaned out of the annulus between the drill pipe and the previous casing while the liner is left in the well (Lyons et al. 2005).
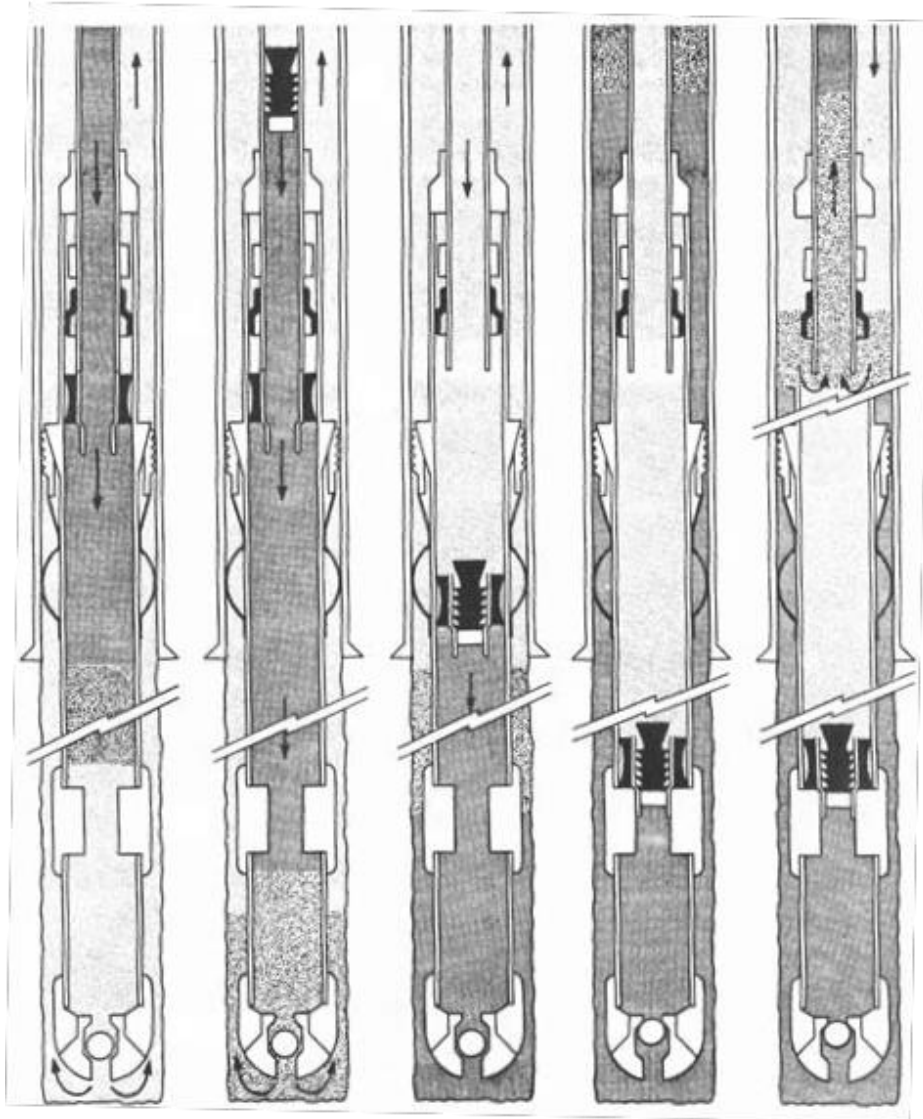
Figure 12 Liner cementing (Lyons et al. 2005).

4.2.1 Cementing challenges

In HPHT wells there are large variations in temperature and drilling fluid is exposed to a wide variation of temperatures. The tieback string is exposed to all the various load conditions shortly after it is installed. To meet the requirements for short term and long term for the tieback string is therefore very challenging.

Tieback casing string requires a long column of cement. The cement column is determined by the amount of lateral support required to prevent the casing to buckle.

The static temperature at the TOC column and at bottom of the cement column can be significantly different from each other. During placement, the temperature at TOC can be substantially lower than the bottom hole circulating temperature. Temperature is a critical factor when it comes to cement hydration. The slurry design can be difficult, due to the temperature differentials. The temperature and pressures variations produce stresses on the casing and cement. The material can exceed the property limits as a result.

It is recommended to have good cement placement during the cement operation. The prevention of bypassed drilling fluid is another critical factor during the cement operation for tieback strings. The trapped fluid in the annulus can expand and there can occur a temperature increase during production, which can create large pressures on the inside and outside of the casing string (Chief Counsels Report).

5 Considerations during Selection of Production String

Liner tieback string is often selected as a production casing rather than a full string casing in HPHT wells. The liner operation is a more complex and hazardous operation to perform than the long casing string. However the liner tieback string can offer more versatility than the full string casing. Some of the reasons for selecting a liner instead of the full string are:

- Isolation of lost circulation zones.
- Isolation of high pressure gas or oil zones.
- Case sloughing and plastic shale's.
- Better drill pipe hydraulics.
- Decreased weight to be suspended from casing head.
- Decreased weigh and grades of steel required to case hole.
- Easier to repair poor primary cement job.
- No weighted mud in the annulus behind the casing string.
- To repair parted, damaged or leaking intermediate casing string.
- Option of tying back casing to surface later.
- Casing, equipment and servicing costs.

A liner can be run in a two-section tieback method, which reduces the weight and grades of casing required to case the hole. The collapse resistance of the steel is increased, due to the upper section has less tensile load compared to the long casing string.

The liner solution can also provide less weight suspended from the casing head, because the lower section is suspended from the liner hanger and the upper section hangs from the casing head. The decrease in pipe weight allows for smaller drilling rigs. The derrick stresses will also be lower with a liner than when running in hole with a full string casing.

Gas can channel behind the full string casing after the cement operation. The conventional cure is to perforate and squeeze the casing. This can lead to a leak in the perforations, which in worst case can lead to casing collapse. The liner tieback string squeezing operation is performed at the top without the need for perforating the casing. The tieback string can also be tied back to the surface at any time.

To hold high-pressure gas, extremely heavy mud is required. When running the full string casing into the mud, any mud that is left above the cement will be weighted. The column of mud that is left behind the casing can be a problem; because of the mud weight inside the casing is reduced to drill any deeper. If the casing design does not allow for heavy mud inside the casing there could be a potential collapse hazard. The heavy mud in the annulus cannot accumulate during cementing of the liner. The lighter mud is left behind the tieback string; the mud weight can be reduced before cementing the tieback string. Resulting in an increased safety factor for collapse compared to the long casing string. The tieback string is often circulated with cement back to the surface leaving no mud in the annulus.

A full string casing will not permit conventional cement stage tool in an extremely close-fitting hole. The formations that are cemented are not competent enough for cement to be circulated to the surface.
The liner tieback string is cemented in two stages, leaving no need for stage tools.
If the liner is properly cemented then the tieback string can be cemented to the surface.

The combination of liner and tieback string can use tapered drill pipes. The use of tapered drill pipes improves drilling hydraulics and also they have the advantage with decreased pressure drop. The liner tieback string can therefore be a safer choice in HPHT wells, due to improved hydraulics. The cost of drilling larger hole and casing it with a full string may be prohibitive with the use of liner. Other considerations that need to be assessed when selecting the liner tieback string as a production casing are:

- Liner that is tied back to the wellhead provide two barriers internally and two barriers externally, while a long casing string has one internal barrier and two barriers in the annulus.
- After drilling of the section, the liner can be installed relatively quickly compared to the long string. This can reduce problems with wellbore wall stability.
- Using a liner can give less damage to the formation. During mud circulation, the forces acting on the formation are reduced, because of the lower flow velocities around the drill pipe. Also, since the casing length is shorter than long casing string the annulus frictional pressure decrease.
- Internal capacity of the liner plus the landing string is less than the long string; therefore it is less likely that cement contamination will happen using liner.
- If a liner is stuck prior reaching bottom, it can be cemented and remedial actions can be taken. The long casing string requires reaching full depth in order to properly land the casing hangar in the wellhead.

The liner/tieback combination provides more opportunities for barrier replacement compared to the long casing string. If the cement job does not meet the expectations there are more options available to mitigate the problem with a liner configuration. The liner provides additional annular barriers if- in addition to the cement barrier a mechanical liner packer is installed on top of the liner. A tieback string can also be installed with an extra mechanical barrier.

During well planning, a successful primary cement job and achieving full zonal isolation is of uppermost importance. Liner tieback string is in general shorter and lighter and can in some cases also be rotated and reciprocated during cementing, which increase the mud to cement displacement efficiency in the annulus. Unfavourable rheological properties between the mud and cement, and poor standoff can be compensated with pipe movement.

The total annulus volume behind the liner is small compared to a long casing string and the hydrostatic head is normally also not too high. In order to reduce the contamination more excess cement slurry can be pumped in order to get the

contaminated slurry above the liner. If a liner packer is set immediately after pumping the slurry, the excess cement above the liner can be circulated back to surface without generating losses.

For well design considerations, the liner tieback string has different load curve compared to the full production string. The load curve is not only for the liner or tieback string, but also for the previous casing where it is hung off both for a liner alone or for liner/ tieback combination. The liner or a tieback is never designed by itself but as a continuous part of another string of casing. The main load that differs the liner tieback design and the full string design is the tension load, because the liner is a separate part of a longer string.

A thicker wall pipe offers better corrosion resistance of wear over lifetime of the well. However the thicker wall pipe has heavier weight, which will be a problem in wells where the pipe is below the critical inclination angle, because in these wells there is a need for greater force to push the pipe into the well. In these wells it is better to select a lighter pipe.

The tieback string offers substantial savings in steel, which increase the capital cost. However there are additional risks and tools that need to be implemented with the liner tieback string. When the operators shall select the production string, considerations with the extra tools and the complexity of the liner solution has to be taken into account. Also the potential capital savings are an important factor (American Petroleum Institute 2013; West et al. 1966; Byron 2014).

5.1 Deepwater Horizon accident

British Petroleum's (BP) oil disaster in Gulf of Mexico is considered one of the largest marine oil spill in the history of the petroleum industry, 11 people died and were never found. An uncontrolled flow of fluids and gas came out of the drilling riser and possible the drill pipe on the evening of April 20, 2010. There were two explosions from the drilling rig and a huge fire that followed shortly after the blowouts.

Investigations and reports after the accident have shown that the disaster could have been prevented if BP had followed already existing safe guidelines and practices from the industry. The decisions made prior to the accident did not take the safety for the personnel and environment sufficient into consideration.
According to the Chief counsels report 2011 the evidence from the accident indicates that when they had the opportunity to save time and money they did shortcuts in order to save time, which played a key role in the decisions that were taken prior to the accident.

The production casing design and construction on the Deepwater Horizon was challenging. The formation at the bottom of the well had low fracture pressure gradient, and lost circulation problems had been experienced. BP decided to not drill the well deeper in spite the narrow drilling window. They also converted the well from an exploration well to a production well. They decided to use a long string production casing design, before temporary abandonment. BP used a full string casing design, rather than a liner tieback string as the production casing. There were four factors that contributed to the decision of rather use a full string than a liner tieback string. The factors that were taken into considerations were:

- Zonal isolation
- Annular pressure build up
- Mechanical barriers and integrity
- Total lifetime cost

BP determined that neither liner tieback string nor the long string design could achieve zonal isolation. Both designs would require adequate centralization, proper cement design and placement.

After several lost circulation events, BP considered to use a full string design. The liner would have been a more complex and a leak prone system and it would have been easier to cement the liner than the full string casing.

Simulations showed that the cement could not be reliable with the use of a full string design, therefore Halliburton`s design team decided that the liner and tieback string were a better option. The decision met resistance from BP, and the company engaged a cementing expert to review the production string design.

BP determined that the best way to prevent APB was to leave an open annulus at the bottom of the last casing string. Also BP`s design showed that both the full string and the liner tieback would have the same number of barriers. There was higher risk with mechanical integrity failure with the liner tieback design, due to the complexity of the installation. The liner option would create a trapped annulus, which could increase APB risks.

The initial cost of the liner tieback option was less than the full string option, but if both material and installation cost were included in the estimation, the liner option would have exceeded the cost of the long string option. At last BP decided to use the full string casing design as an acceptable design. The full string casing design had decreased cost mainly due to faster installation time.

From the Chief counsels report 2011 one can draw out that there would have been a safer option to select the liner tieback string design. The liner tieback string design provided more barriers against potential gas flow up the annular space than the long string design, although the liner tieback option would have taken extra time and been more expensive. The decision to use a long string relied on saving time and cost for the operation. The long string design contributed to the risk of having a poor cement job with the risk of mud contaminating of the cement (Chief Counsels Report 2011; CCRM 2011).
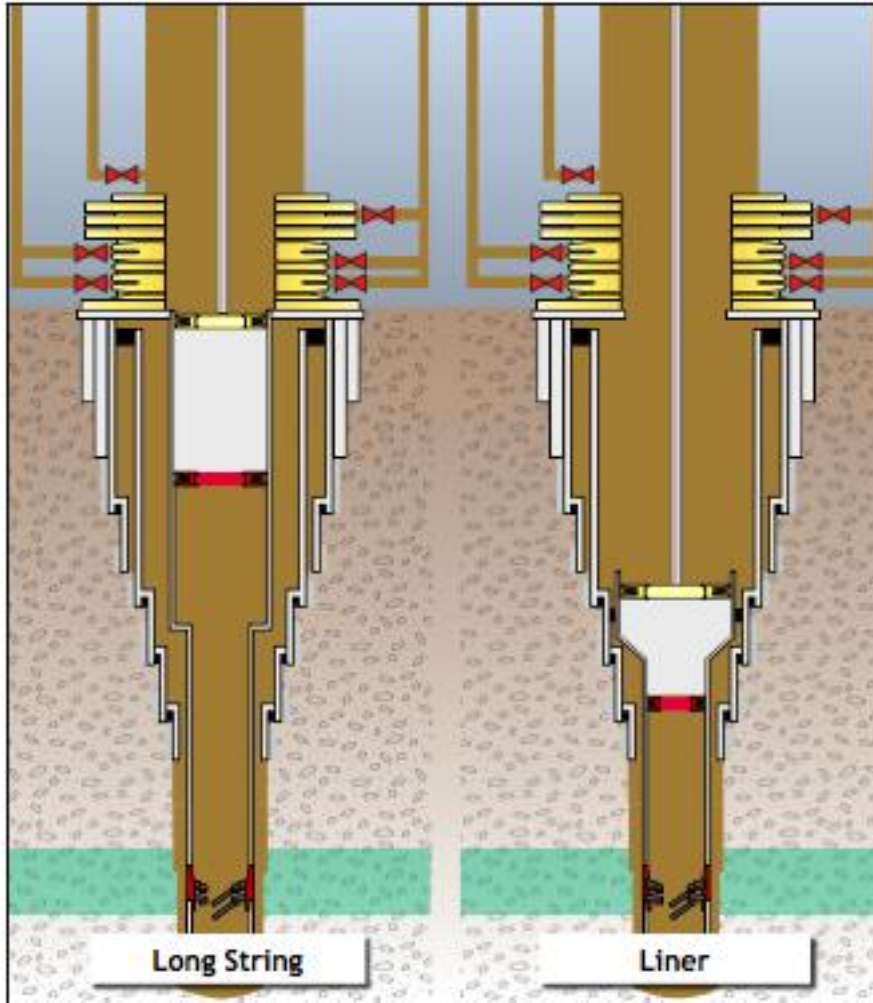
Figure 13 Cementing a long casing string versus a liner (Chief Counsels Report 2011).

6 Case Study Martin Linge

This chapter presents a study from the Martin Linge field in the North Sea. The case study will present two wells in the Martin Linge East structure, with special emphasis on drilling the 12-¼ in section. Drilling of the 12-¼ in section is identical for both wells. The study will first present well A-08 where a combination of a liner tieback string is used, while well A-09 used a full string production casing. The purpose with the study is to show how these two solutions differ from each other in practice.

A limitation to the study is that the Martin Linge field is not classified as a HPHT well. The Martin Linge East structure represents the highest wellhead shut-in pressure of 640 bars, which is right under the HPHT classification.
It was decided to not classify the well as HPHT. There are strict internal company rules that need to be followed if the well is classified as HPHT. The internal requirements where though followed when drilling the last meters above the Brent reservoir and also when drilling into the main reservoir.

Most of this chapter is retrieved from Total E&P Norge internal Well Programs and Guidelines, If not otherwise stated.

6.1 Introduction to the Martin Linge Field

Martin Linge is a development field in the North Sea. The field is situated 42 km west of the Oseberg field and lies in close proximity to the UK border. The water depth is approximately 115 metres. The field contains both faulted and segmented gas accumulations in the Middle-Jurassic Brent Group and a shallower oil reservoir in the Frigg formation. The main gas/condensate reservoir is complex and is exposed to high pressure and high temperature. The main operator is Total E&P Norge AS (51%), partners are Statoil (19%) and Petoro (30%).

The Martin Linge field was discovered in 1975, but was never developed because of uncertainties. The main issue were the complex structural settings of the Brent reservoirs. In 2009-2010 Total drilled an appraisal well to evaluate the connectivity through faults at the Upper Brent level of Martin Linge East structure with an

extended well test.

In 2003 and 2005 there were made several seismic acquisitions. A significant improvement of the structural interpretation and field understanding were a result of these acquisitions, which made the Martin Linge area a further target for development appraisal (Denney 2013).

In 2014 Total started drilling the first production wells in the field, and the field is planned for production in 2018.
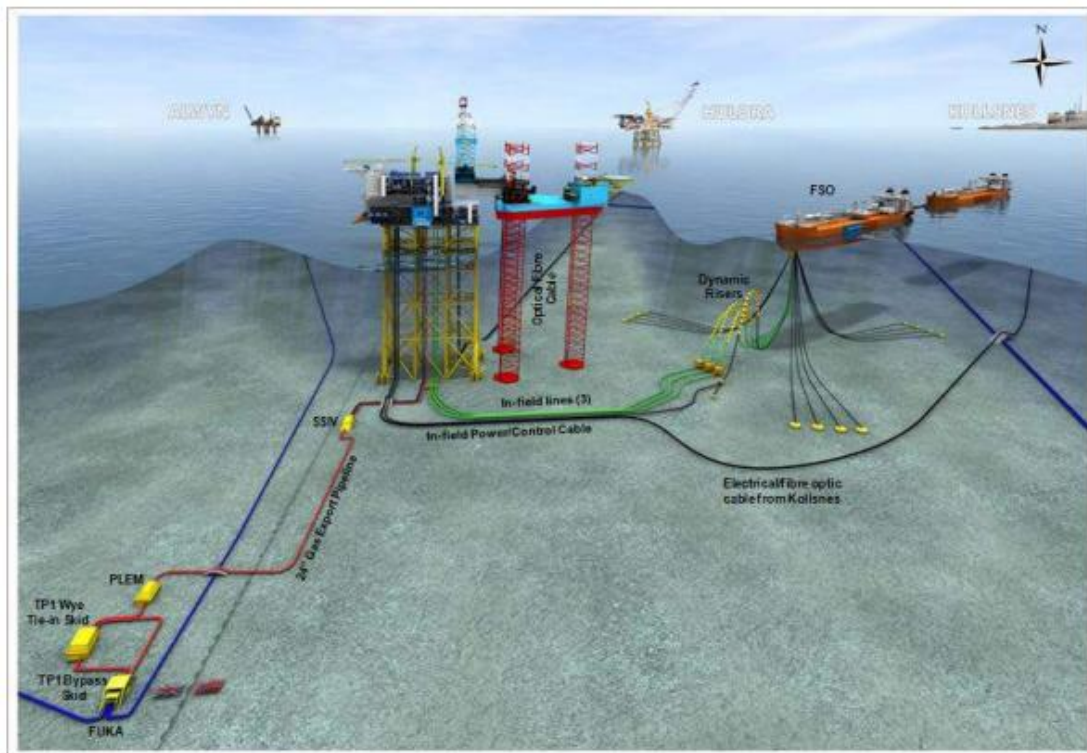
Figure 14 Martin Linge Field (Total E&P Norge, 2014).

6.1.1   Brent

The main objective with well A-08 and ell A-09 is to drill through the Middle-Jurassic Tarbert sands of the Brent Group. The geometry in the Middle Jurassic Brent reservoirs has minor facies and laterally changing thickness. A gas cloud lies above the Martin Linge East field and the quality of the drilled holes is variable along the field. The East Brent structure has a 250 m hydrocarbon column with high content of CO_2 and H_2S.

The Martin Linge East structure represents the highest wellhead shut-in pressure and there is high condensate fraction and heavier gas fraction in this structure compared to the other structures. The maximum equivalent wellhead pressure is 624 Bar with a working pressure of 640 Bar. The maximum wellhead temperature for the Brent Group is prognoses to be 120 Degrees Celsius.

6.2 Production Casing Design

The casing design for both wells is based on a worst-case pressure and temperature scenarios. A casing wear of 10 % for vertical sections has been included in the design for the production casing strings for the gas wells. The loads that are included in the casing design are:

- Burst load case 1-BLC1: Bullheading a well full of formation fluids.
- Burst load case 2-BLC2: Bullheading over tubing leak.
- Burst load case 4-BLC4: Pressure test.
- Collapse load case 1-CLC1: Cementing operation.
- Collapse load case 2-CLC2: Casing evacuation while drilling.
- Collapse load case 3-CLC3: Casing evacuation during production.
- Collapse load case 5: Thermal Expansion.
- Tension load 1- ALC1: Running in hole.
- Tension load 2: Overpull 100 MT.
- Tension 3: Thermal expansion-axial production.

The minimum design factors that need to be followed for the production string are:

Casing	10-¾ in x10 in Production
Collapse	1.1
Burst	1.1
Tension	1.3
Tri-axial	1.25

Table 1 Minimum Safety Factors

6.3 Main challenges with Cementing Design

The cementing design follows the requirements from NORSOK D-010 standard and Totals internal rules. The cement operation main task is to achieve long-term zonal isolation and ECD limitation must be accounted for during the cementing.

"A life of the well" study has been modelled to ensure the long-term zonal isolation. The cement sheath behaviour is modelled under expected loads from the well operations. Also there are performed hydraulic simulations for the 12-¼ in section, because of the low ECD margins when running into hole and cementing. To achieve long-term zonal isolation it is vital to select the correct slurry and set cement properties for the entire production period for the wells.

6.4 Well 30/4 A-08 Liner Tieback String

Well A-08 is drilled as a slanted producer in the North of the Martin Linge East structure and is located within the complete Upper Brent section. The well was drilled vertically in 12-¼ in section to Target Depth (TD) with a mud weight of 1.85 Specific Gravity (SG).

Well A-08 has narrow mud weight window, which makes the well challenging to drill. Therefore ECD management is of major importance to safely drill the well, without experiencing any sudden pressure fluctuations. If pressure fluctuations occur it can lead to an unexpected influx or mechanical damage of the well.

Well A-08 is one of the first two Brent wells that will be put on production at the Martin Linge field. A figure of the well schematics for well A-08 is shown below
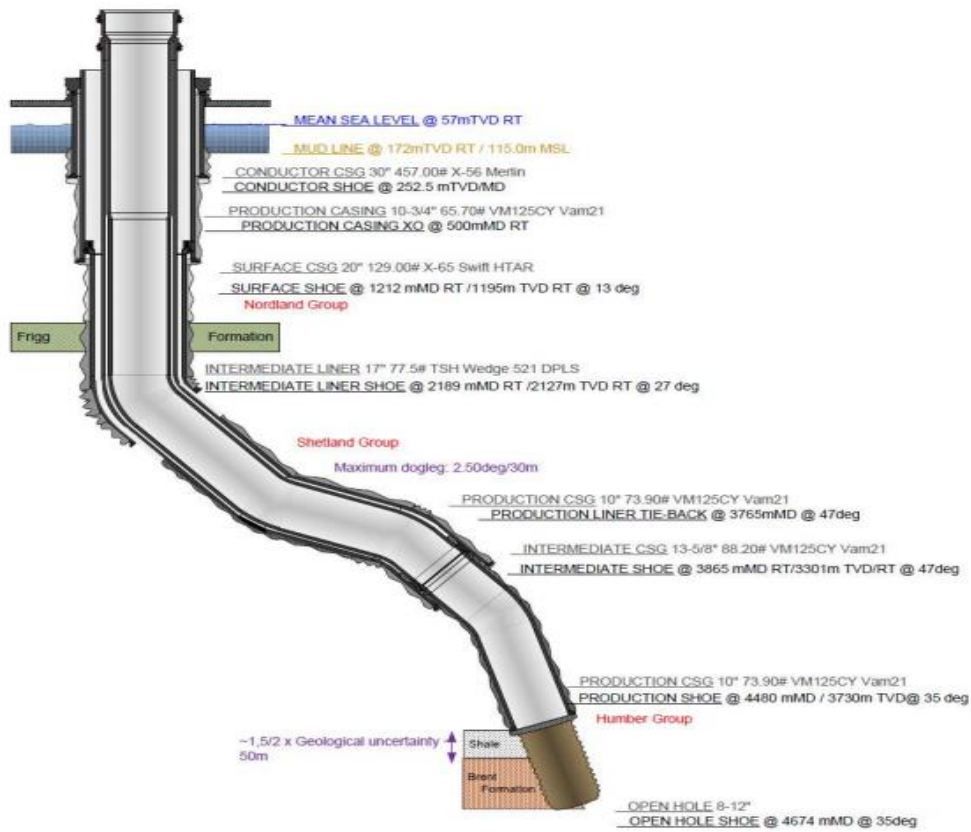
Figure 15 Well construction schematic, well A-08 (Total E&P Norge, 2015).

6.4.1 Production casing design

The gas pressure is calculated with the assumption that the Martin Linge East structure represents the highest wellhead shut-in pressure. There will be full surface monitoring of A/B/C annulus, because the excessive annulus pressure can cause burst or collapse of the casing. The casing design is based on worst-case pressure and temperature scenario. The production casing design is important, to ensure that the load cases are kept above the minimum safety factors. The calculated loads for the 10-¾ in x 10 in Tieback & liner are shown below.

Production Casing	Casing Properties	Burst (1.1)		Collapse (1.1)		Axial (1.3)		Tri-axial (1.25)	
		Min SF	Max Load Case	Min SF	Max Load Case	Min SF	Max Load Case	Min SF	Max Load Case
10-¾ in Tieback	10-¾ in 65.7 lbs/ft, VM125 CY	1.15 at Surface	BLC2 Tubing leak	5.05 at 480m	CLC4 Evacuation during production	2.66 at 300 m	ALC1 Running casing	1.51 at surface	BLC2 Tubing leak
10 in Liner	10 in, 73.9 lbs/ft VM125 CY	1.15 at 500 m	BLC2 Tubing leak	1.15 at 4480m	CLC4 Evacuation during production	2.66 at shoe	CLC4 Evacuation during production	1.90 at shoe	CLC4 Evacuation during production

Table 2 Max load case and minimum safety factors for liner and tieback string (Total E&P Norge, 2015).

The well specific safety factors for the liner and tieback design are sufficient enough compared with the minimum safety factors; thereby it is an acceptable design for well A-08.

6.4.2   12-¼ Section

The 12 ¼ in section is a long section and it ends near the predicted reservoir. The section was drilled from 3301 meters True Vertical Depth (TVD) to 3730 meters TVD into the Heather formation. The pore pressure inside is above the Brent reservoir and the section contained slightly shale gas. The well was drilled with a non-aqua based mud with density of 1.85 SG. There was a slightly uncertainty above the Brent reservoir.

With narrow drilling window it is important to have a correct mud weight for the overburden formation and the ECD needs to be monitored closely when drilling through these sections. Hole cleaning is challenging for the-12 ¼ in section. To ensure proper hole cleaning, the real time drilling parameters along with the drilling fluid properties are optimized. The drilling fluid program is based on Total HPHT drilling fluids.

6.4.3 Procedures liner

A liner and tieback string was used as a production casing for drilling this well. The liner tieback string is run and cemented in two stages, first liner then the tieback string. The drilling fluid was a non-aqua based mud with a density of 1.85 SG. The liner shoe was set at 4520 meters Measured Depth (MD) and cemented 400 meters up. A pressure test was performed with both the liner and tieback string. The liner was set from the base of the 13-5/8 in casing to target depth.

Liner installation procedures are particular important for HPHT wells, because of the narrow drilling window. The hole has to be stable enough with no indication of fill on bottom and the mud should have good properties.

The bottom joints and float equipment are installed with a thread-locking compound. The thread-locking compound is applied to the threads and prevents backing out the casing joints while drilling out the cement. The float equipment is installed at 2846 meters MD and to ensure that the floats are not plugged, circulation through is confirmed at drill floor immediately after made up to the string.

The liner has to be full of mud before the liner hanger is made up. The liner hanger is set at 2849 m MD. As the liner is run, the drag is carefully monitored to ensure there is filling at bottom depth, due to precaution for plugging the shoe. Circulation needs to be established when the liner is near bottom depth, due to washing and removing of foreign material that might be in the liner hanger slips.

The liner is run to the desired setting point and hung off before cementing. The Drill pipe is then picked up to check if liner is properly hung off after release of the running tool. If the drill pipe is free then adequate weight is placed on the liner while circulating and cementing.

Before cementing, trip gas that might have accumulated on bottom needs to be circulated out to achieve a good cement job. The liner is always circulated before the cement job to ensure that foreign material does not plug the floats during cement job (West et al. 1966)

After the liner is circulated, the cement job can be performed. The liner was cemented from the liner shoe and 400 meters up. The objectives with the liner cementing design is to:

- Provide zonal isolation of permeable formations, to prevent communication to surface or other formations.
- Provide a good hydraulic seal around the casing shoe to enable a formation integrity test/ leak- off test for further drilling.
- Isolate any hydrocarbon bearing formation with flow potential with a minimum of 200 meters cement above.

Before cementing job is performed the amount of cement required for the job need to be established. This is performed with a Caliper log that measures the diameter of the borehole at numerous locations in the wellbore. The Caliper log accommodates for irregularities in the wellbore diameter and determines the volume of the open hole. The cement properties are also an important consideration before cementing operation. The proper set cement is determined and the density and viscosity of the material.

The cement is mixed and pumped after the circulation is completed. A batch mixer is used for smaller volumes and assures homogeneous cement slurry. This is done to create slurry. For bigger jobs the cement is mixed "on the fly" in a small mix tank while being pumped in the well. The cement used is Flexstone tail slurry with density of 2.05 SG.

Cement is pump into the well and displacement is pumped behind the wiper plug. A drill pipe wiper plug is released behind the cement. The wiper plug is used to separate the slurry from other fluids and it reduces contamination and improves the slurry performance. The circulating rate is substantial reduced as the wiper plug is near the bottom of the drill pipe. The liner-setting tool is latch into the liner wiper plug. The liner wiper plug consists of sheared pins. These two plugs goes down the liner behind the cement as a single unit. Behind the liner wiper plug, the volume of displacement fluid is pumped to the plugs lands on the landing collar. Pressure test can then be performed.

A ZXP liner top packer from Baker Hughes is used. The ZXP packer is installed with

a seal element to carry out high circulation rates in difficult wellbore environments. The liner top packer is run as an integral component of the primary liner hook-up and has hold-down slips. The hold-down slips allow the packer to be run with a tieback string. The liner packer will seal off the space between the liner and the next casing. Without the use of a liner packer, circulation when excess cement on top the liner is circulated out direct or reverse. The excess cement will flow back into the drill pipe from the annulus, while the setting tool is pulled out of the liner hanger. Allowing this flow-back on top of the liner before pulling the pipe will avoid solid cement on top of the liner and flush the PBR with clean mud.

A constant hydrostatic pressure is held on the gas producing formations to achieve a better cement job. The hole is then kept filled, while the setting tool is retrieved. If the fluid level in the annulus is allowed to drop, the cement job can be ruined.
The presence of gas can complicate a liner cement job. When gas is present in the mud, there can occur gas-cut cement at top of the liner. Heavy fast- set cement is often used to avoid loosing circulation.
The 13-5/8 in annulus and liner top packer is pressure test before the running tool is retrieved out of the hole (West et al. 1966).

6.4.4 Procedures tieback string

When the liner has been pressure tested, the tieback string can be run. The tieback string also allows for being run later. The tieback string is run to tie the liner back to the surface and to isolate the casing outside that might have a lower pressure rating. The tieback string also protects the liner against wear and corrosion. A 10-¾ in tieback string is in fact an extension of the liner back to the wellhead and must support the same loads as the liner.
During the procedure of running tieback string the wear bushings are first retrieved. The wear bushings are used to prevent casing head seal from damage during drilling operations. Then the PBR seal assembly is run downhole. The PBR seal assembly is the bottom part of the tieback string and is several meters long in order to allow for string movement keeping the pressure seal inside the PBR.
The tieback string is sting into the PBR, because of the temperature variation in the wellbore. The tieback string with a wiper plug landing-collar is then run to target

depth. The tieback seal assembly is inserted into the PBR and is pressure tested. The pressure test ensures the casing string integrity. The top of the tieback string or PBR is tagged by installing a circulating head. It is important to circulate slowly to observe for pressure build-up. When the pressure builds up the mud pumps are shut off. The drill string is then pulled above the tieback position. The string is slowly lowered to check if there is a decrease in string weight. A decrease in string weight indicates that the stem seals are entering the tieback string or PBR.

The next operation is to cement the tieback string. The 10 in tieback string is cemented from PBR at 2799 m MD to 300 m above cementing port on tieback seal. The objectives for the tieback cementing design are:

- Provide a good hydraulic seal above the 13-5/8 in casing shoe.
- Isolate stage-cementing tool in 13 5/8 in with 200 meters cement above.

The tieback string is cemented with Flextone tail slurry with a density of 2.02 SG. TOC is 300 meters above circulating port. Cement evaluation logs are run behind the production casing to ensure proper bonding between the casing and formation. The tieback cementing operation is followed with the same procedures as the liner-cementing job. First the cement is batch mixed and pumped and the cement is displaced with mud behind the wiper plug. The liner-setting tool is latch into the tieback wiper plug.

The 10-¾ in tieback string is landed out in the wellhead with a full-bore running tool. This allows for using a full bore cement head at surface. After the cement job the running tool is released from the string above the casing hanger and the wellhead. At this stage the blow out preventer will be tested. Next step is to install the wear bushing.

Both the liner and tieback string is drilled out after the cementing operation. Also the shoe- track cement is drilled out. A scraper operation is performed to remove scale and debris from the internal surface of the tieback string including the shoe track drilled out. The main task of the scraper operation is to ensure that the wellbore is clean before installing the completion string. At last a pressure test and a CBL/VDL

log is run to measure the cement bond casing integrity to verify that the cement job is good.

6.5 Well 30/4 A-09 Full String Production Casing

Well A-09 was the first well on the field to run 10in x10 ¾ in full casing string and is also planned as a slanted producer of the Brent reservoir. The well is situated right in the centre of the Herja structure. A complete Upper Brent section is also expected for this well.

It was the first Brent prospect well and the main objectives with the well were:

- Prove minimum HC column in Herja structure to complete the well.
- Obtain reliable LWD information for fluid and reservoir characteristics.
- Complete the well with either sand migration solution or with perforated liner.
- Prove a gas-bearing Brent section.

Well A-09 is challenging to drill. In the Hordaland shales there can encounter borehole instability problems. The risk of drilling through hard stringers can result in low rate of penetration and excessive vibrations during drilling. This can lead to loss of circulation. The mud weight window is narrow and ECD management must be performed precisely to obtain a safe pressure window. If ECD management is not performed properly, it can to loss of the well.
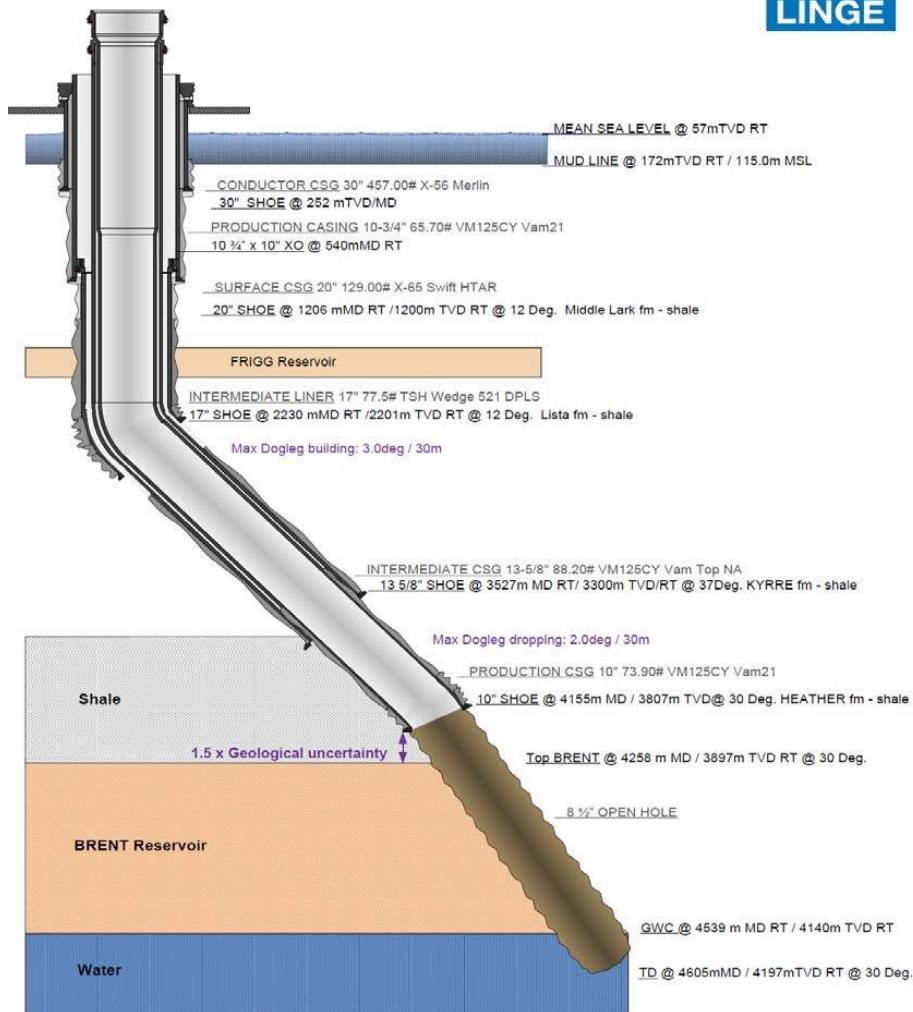
Figure 16 Well construction schematic, well A-09 (Total E&P Norge, 2015).

6.5.1   Production Casing Design

The production casing design for well A-09 is shown below.

Production Casing	Casing Properties	Burst (1.1)		Collapse (1.1)		Axial (1.3)		Tri-axial (1.25)	
		Min SF	Max Load Case	Min SF	Max Load Case	Min SF	Max Load Case	Min SF	Max Load Case
10-¾ in x10 in casing	10-¾ in 65.7 lbs/ft, VM125 CY	1.11 at Surface	BLC2 Tubing leak	3.97 at 530m	CLC4 Evacuation during production	2.40 at 270 m	BLC1-Bullheading	1.47 at surface	BLC2 Tubing leak
	10 in, 73.9 lbs/ft VM125 CY	1.47 at 550 m	BLC2 Tubing leak	1.12 at 4115m	CLC4 Evacuation during production	3.02 at 550 m	CLC4 Evacuation during production	1.84 at shoe	CLC4 Evacuation during production

Figure 17 Max load case and minimum safety factors for long casing string (Total E&P Norge, 2016).

The maximum load cases are kept above the minimum safety factors; thereby it is an acceptable design.

6.5.2   12-¼ Section

The 12-¼ section is drilled from 3300 meters TVD to 3807 meters TVD. The sail angle is kept through most of the section with 37 degrees before dropping to 30 degrees. The drilling fluid used is a non-aqua based mud with a density of 1.85 SG. The well is drilled into the Heather formation above the Brent reservoir. There is a geological uncertainty above the top Brent. The 12-¼ section has high content of background gas. The setting depth for the production casing is above the Brent reservoir. This is due to the mud weight in the 12-¼ in section is insufficient to hold the Brent pressure. The NORSOK standard D-010 also state that the minimum horizontal stress value 30 meters above the production casing shoe depth, shall be high enough to keep integrity with gas from Brent up to this point.

6.5.3   Procedures full string production casing

The first procedure is to run the 10 in x10-¾ in casing string into hole. The 13-3/8 in casing shoe is set at 3516 meters MD and cemented 100 meters up. There is performed a FIT at 13-5/8 in shoe, which shows an equivalent mud weight of 2.02 SG.

First the Unihead Wear Bushings are retrieved. The wellhead and BOP is cleaned by a Vort-X clean out tool to remove debris from the wellbore. The casing string is run to bottom of the well.

The casing is hung off and landed in the casing hanger. The casing hangers are located at top of the well and are implemented threads to suspend the casing in the well. The well has installed centralizers in the wellhead to position the casing strings. The casing is run in stands, 3 joints of 13 meters lengths of casing joints already made up in stands. After the casing is run, drilling fluid is circulated to remove remaining cuttings from the well.

Next procedure is to cement the annulus between the 13-5/8 in casing and the 10 in tieback in order to assure additional zonal isolation to allow drilling of reservoir section. The cementing design for the 10 in production casing uses Flexstone tail slurry with density of 1.92 SG.

The cement slurry is pumped into the well through a surface full-bore cement head with the string above the PBR. Once the cement displacement is completed, the string is stung into the PBR and landed out on the hanger in the wellhead. After the cement job the tieback casing was scraped in the DLT packer area and pressure tested using DLT packer.

6.6 Comparison between the two methods

Key points:

> ➢ Both solutions are drilled in the Brent Group with an identical 12- ¼ in section.

> ➢ Both solutions are installed with casing stand—tripping operations are much faster.

> ➢ Both solutions used non-aqua based drilling mud. The non-aqua based drilling mud is preferred in HPHT wells, due to better stability of the mud when it comes to rheology and fluid loss control.

> ➢ The liner tieback procedure provides more operations to perform than the full string solution.

> ➢ Liner tieback string has reduced ECD compared to the long casing string solution.

> ➢ The 12-¼ in section is a long section, difficult to cement with the long casing string solution.

> ➢ The narrow space between the 12-¼ in hole / 13-5/8 in casing on the whole length from bottom to wellhead will generate high surge pressure—restrictions for the long casing string.

> ➢ Increased time for pressure testing and inflow testing for the liner tieback string.

Comparing the time schedule for well A-08 and well A-09 show that the time used for well A-08 with the liner tieback string used 141.5 hours, while the full string design only used 56 hours. There is a significant difference between the two operations, this is due to the liner tieback solution has more operations to perform and thereby it is more time consuming.

The ECD and ESD simulation is shown below for both the solutions. The ECD from the 13-5/8 in shoe to target depth for the liner tieback string is simulated to be 1.89 SG-1.94 SG, while for the full string production casing from the 13-5/8 in shoe to target depth is 1.93 SG-1.97 SG. The simulations show that the ECD is lower for the liner tieback solution.
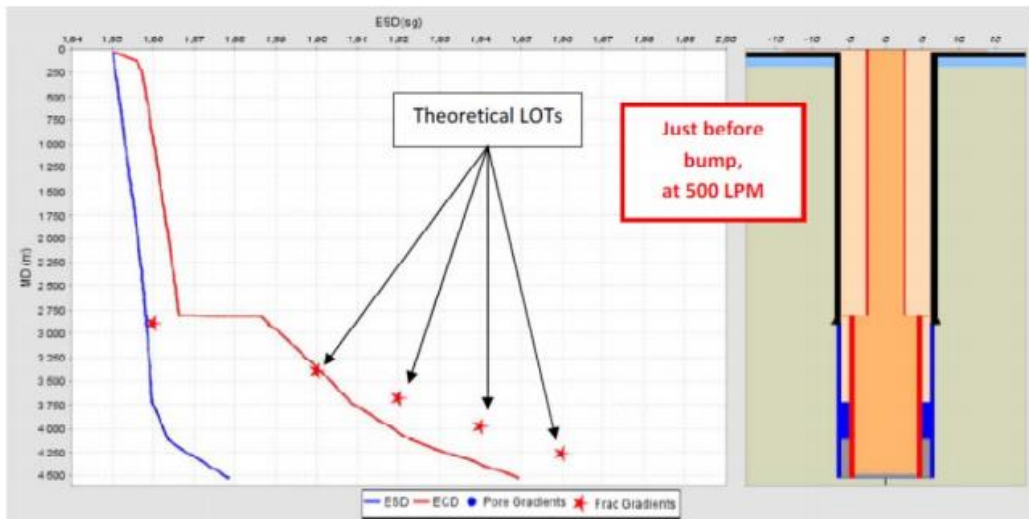
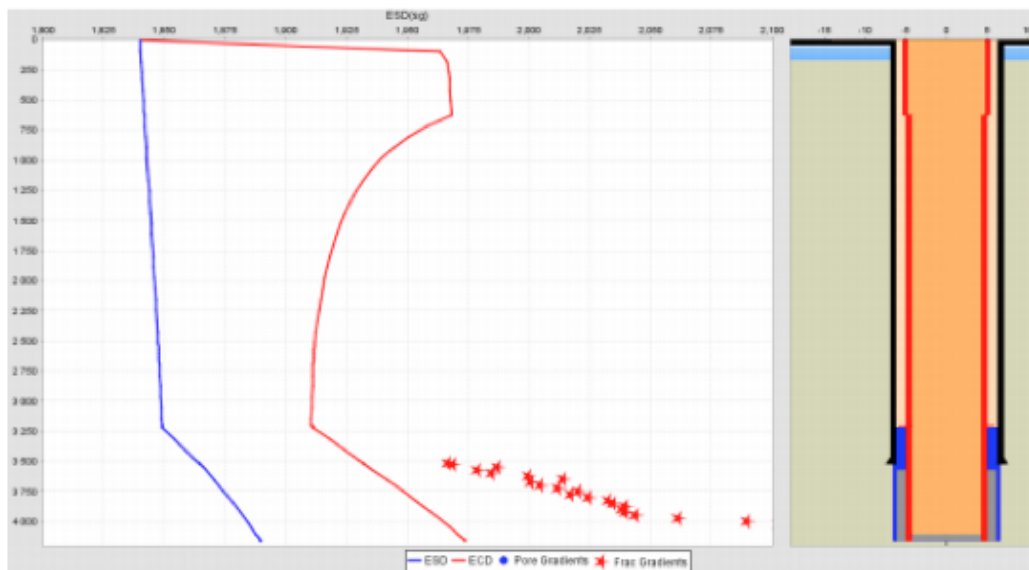**Figure 18 ECD and ESD for liner tieback string (Total E&P Norge, 2015).**

Figure 19 ECD and ESD for full string production casing (Total E&P Norge, 2016).

6.7 Discussion of the Study

Drilling of 12-¼ in hole is identical for both solutions. The only advantage with liner tieback solution is that the open hole can be protected with steel faster. The difference is that the open hole length is picked up, and there is approximately 50 meters overlap inside the 14 in liner in singles from deck. The remaining part of the running string is drill pipe, which is already made up in stands of 27 meters in the derrick. When running full string casing the whole length from bottom to the wellhead has normally to be picked up in singles from deck.

For Maersk Intrepid drilling on Martin Linge, the above statement is not valid since this rig has the big advantage with possibilities for preparing both liner and full string casing in stands while drilling the section. That means the running speed is almost as fast as running stands of drill pipe.

Liner tieback string provides a more leak prone-complex system with more procedures to perform, which increases the risk of a potential failure of the casing string. However running long string casing is a more robust solution. The liner and tieback solution require mechanical sealing downhole to seal successfully.

The ECD management is of uppermost importance when drilling with a narrow drilling window. The liner tieback string provides reduced ECD during cementing. Liner reduces the risk for losses both while running in hole and cementing.

The narrow space between the 12-¼ in hole / 13 3/8 in casing on the whole length from bottom to wellhead will generate high surge pressure putting restriction to the lowering speed when running full string casing. Due to the same fact the flow rate during cementing will be restricted. The surge pressures increase risk of formation fracture.

Running with liner, the landing string from 50-100 meters inside the last casing will typically be 5 in or 5-½ in drill pipe. The space between the casing and drill pipe is much bigger, generating less surge pressure while running in hole and will open up for higher flow rate during the cement job. High flow rate during the cement job will in general improve the quality of the cement job.

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The total time spent for securing the well using a full string casing is less than liner and tieback. Securing the well is to get steel protection in place and isolate with cement. Total E&P estimates about five days longer operation with the Liner tieback solution because of:

- Increased time for pressure testing and inflow testing of the liner packer area. While making up the casing or liner string on the drill floor the quality check of the make up and very good connections reduce the probability of a leaking connection. When the liner is tied back to surface it might be a challenge to obtain a good seal between the liner and tieback even though very robust systems exists. It is evident that making a seal between two parts in a controlled environment at the drill floor is easier than doing it when surrounded by mud and cement in HPHT conditions at 4000 m.
- Two cementing operations. First liner then tieback cementing.
- The casing needs to be run two times. First liner from drill pipe to setting depth, than the tieback string.
- Increased time to drill out cementing equipment. If the liner is cemented to the top, cement might fall inside the liner. It is normal to drill out this cement with a bit plus scrape on bottom and a mill polishing the seal face and top of the liner called Polished Bore Receptacle (PBR). This PBR shall receive and seal against an eventual tieback string.

Both systems require tested barriers in order to be accepted. I think that this is easier to obtain using a full string for the steel part of the barrier (casing/liner) using fill sting casing. But good cement is also a barrier and this is better to achieve using a liner tieback system.
The formation drilled through represented high content of gas. The use of liner will isolate the gas down-hole and provide more barriers compared to the full string.

A full string design is selected as long as it is technical feasible. This is because the liner tieback string is complex and time consuming. Key factors one can draw out from the study for selection of production string:

- Good primary cement job.
- ECD management.
- Barriers.
- The depth interval of the section to be drilled and cemented.
- Content of gas.
- Time spent on each operation.

7 Conclusion

The long string alternative can be a good choice when the geology of the area is well understood, and when the wells are experiencing lower pressure. In HPHT wells the use of liner can be a safer choice, because of the high pressure these wells experience. The long string design is fully reliant on a good primary cement operation, while the liner has several more barriers and an improved situation for a successful cement job. Cementing a long string is more difficult than cementing a liner. The liner mitigates the risk of losses during cementing, but the long string design can offer better well integrity over long term than the liner option. The long casing string can offers better well integrity over long term, because the long string does not have a seal assembly and PBR.

The liner is a complex system with several more components than the long string design. There is an increased need for pressure testing and inflow testing of the liner packer area. The liner tieback string needs two cement jobs and two casings needs to be run into the well. Also it takes longer time to drill out the cementation equipment than with the long string.

BP is criticized for selecting a long string design instead of a liner. The quality of the bottom hole cement job in the Macondo was not good enough. The Chief Counsels Report states that the flow came up through the shoe track of the production casing. If there had been a good primary cement job, the cement should have stopped this flow.

I started the dissertation with the impression that the selection of production string was most dependent upon the casing design and the anticipated loads the casing should withstand during its productive life. During the study I found out that the uppermost important factor prior to selecting the production string is to have a good primary cement operation. The cementing job is the key to successful drilling.

The liner tieback string may have more versatility and several advantages when it comes to ECD management and it can provide more barriers. However considerations have to be accounted for the time spent on each operation and the well integrity over lifetime. Although the liner comes with several advantages, the long string option is

operationally easier and is less time consuming. My opinion is that the long string option is the preferred one, assuming that the formation strength is sufficient for the cement job.

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*Personal communication Torleif Saevareid.