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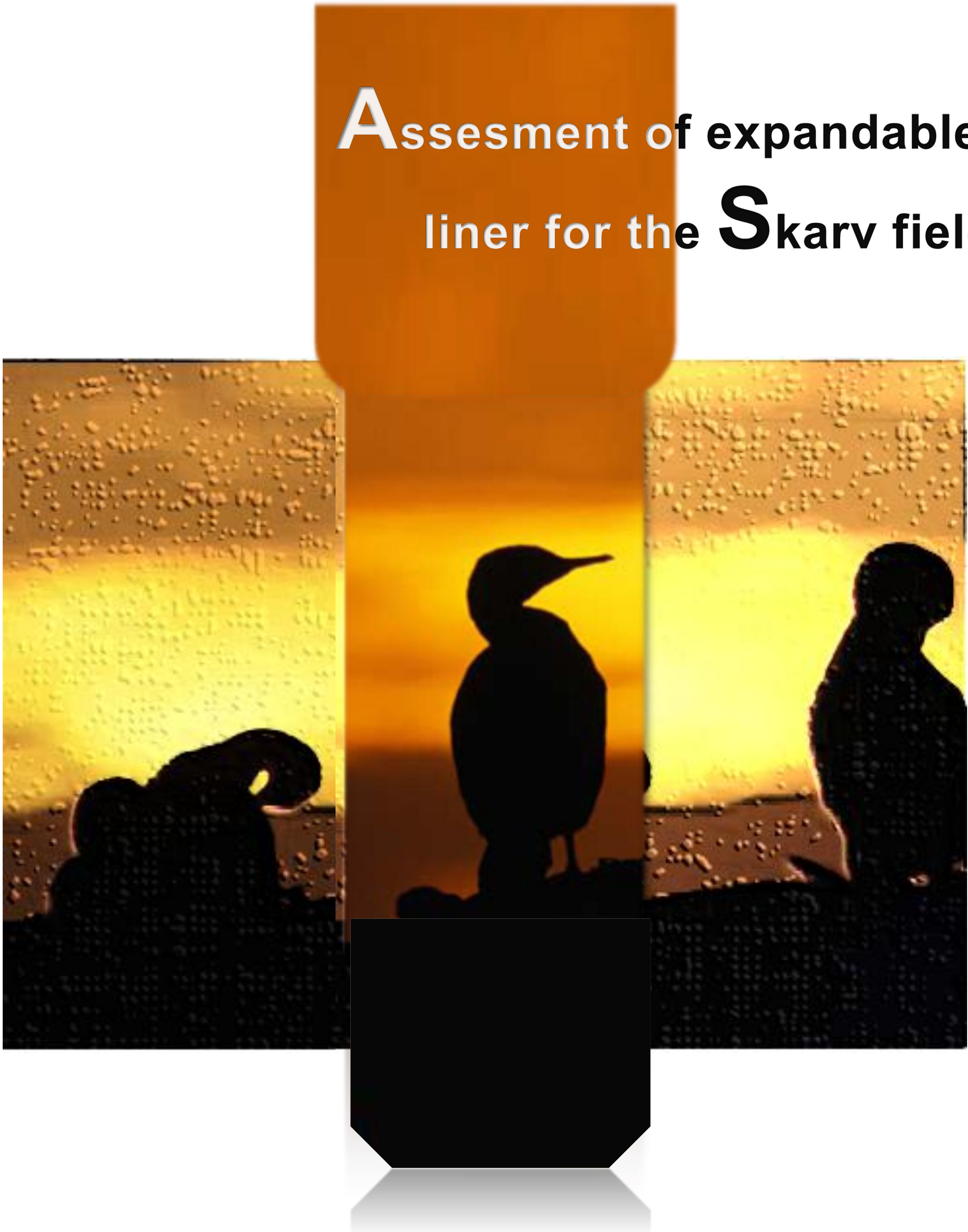
To my family

Assesment of expandable liner for the Skarv field



Master thesis by
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December 2012

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Ragnhild Abercrombie

Abstract

BP's Skarv field is a stacked three layer reservoir structure. The field development plan involves drilling deviated and horizontal wells into the uppermost reservoir layer, Garn, and the lowermost reservoir layer, Tilje. Above Garn is a high pressure zone, that requires 1.59 sg mud weight to be drilled. When Garn have proven to be a strong formation, the overburden and Garn is drilled as one section in Skarv drilling phase 1 to reach Tilje. A 9 7/8" shoe is set in top Tilje and the reservoir section in Tilje is drilled with an 8 ½" bit and left open hole and completed with gravel pack. The drainage strategy involves pressure support in Tilje, hence Garn will deplete with a faster rate.

In phase 2 Garn will have depleted to an extent that drilling with 1.59 mud will become a to large overbalance regarding differential sticking issues. The 9 7/8" shoe must therefore be set in top Garn. Due to the low pressure in Garn, Garn must be sealed off before drilling Tilje to avoid crossflow from Tilje into Garn. Garn and Ile, the middle sand, will be drilled with an 8 ½" bit. Traditionally a 7" liner will be set between top Garn and top Tilje. This will give a slim hole solution in the Tilje reservoir section which can lead to insufficient gravel packing resulting in hole collapse. It was proposed that expandable liner could be the solution to maintain an 8 ½" hole in Tilje.

Available solutions for Skarv have been identified and Expandable liners from two vendors, Enventure GT's SET® open hole liner and Baker Hughes linEXX™ monobore liner have been analyzed in StressCheck for installation, drilling and production loads an expandable liner could possible need to endure through the life off the well. Skarv's J-4 well, Skarv basis of design, Skarv casing design, NORSOK and BP internal regulations are used to set up a model in StressCheck.

Expandables are special tubulars that are expanded down hole by mechanically or hydraulically pushing or pulling a cone or mandrel through the tubular. beyond the yield point, permanently deforming the pipe. When undergoing such expansion the mechanical properties of the pipes are changed. To gain a complete picture of what load scenarios the expandable must endure, the expandables were modeled both as pre- and post expanded.

The analysis includes five different pressure regimes and four different mud weights as drilling and displacement fluids. Pressure regimes were calculated based on the expected depletion rate in Garn and mud weight were calculated based on minimum required mud weight in relation to well stability.

Output from the analysis are safety factors, SF. For Skarv, minimum required SF for burst and collapse loads are 1.10 and 1.00 for collapse. In general, the limiting factor for an expandable is the collapse strength. The results however show that the limiting factors for depleted Garn is related to the burst loading, when the liners internal pressure which is the weight of the mud and the applied surface pressure, as in a pressure test, will exceed the low external reservoir pressure. For the 7.625 X 9 7/8" SET® liner, the minimum SF was 0.93 for burst and 2.35 for collapse. For the 8.625 X 10 3 /4" SET® liner, the minimum SF was 0.88 for burst and 2.02 for collapse. For linEXX™ liner was 0.73 for burst and 1.32 for collapse. For all cases it was the high test pressure and injection pressures that casued the low SF. The internal pressure in a well is the pressure that can be controlled, which propose that expandables are a god solution for depleted reservoirs. By designing the well parameters to ensure the liners burst limit will not be exceeded, by e.g. tailor making the mud weight, expandable liner can be installed in Skarv wells. The expandables are not easily modeled in StressCheck when it proved challenging to ensure the correct properties are input for the pre- and post-expanded pipes and combining the two. For StressCheck to be a reliable tool for expandables, vendor should supply exact numbers or a

range for both the pre-and post-expansion properties as the input variables required in StressCheck.

Both SET® and linEXX™ is considered as options for Skarv to ensure a 8 ½" hole in Tilje but with certain restrictions and requirements. SET® required a 10 ¾" base casing appose to the 9 7/8". Installation wise this is a possible solution, but requires redesign of the well. linEXX™ is a top-down expansion system resulting in shrinkage of the liner at bottom. To ensure the required post-expansion liner length, excessive liner need to be installed and a rat hole is required. This can be a problem when the liner shoe is to be installed just above top Tilje without penetrating the formation. If Tilje and Garn is exposed at the same time, this can result in crossflow. Installation- and strength wise, expandables can be a solution for Skarv. The concern however is that currently no expandables are gas tight which is requirement for a production liner. Whether the expandable liner is to be installed as a liner or act as well construction is debatable.

The risk is considered no higher than the alternative slim hole solution and experience from other field apply that the expanadable liner solution will not be excessive. The highest cost is probably time spendt on designing a system that have all the requirements for a production liner if this is needed.

Table of content

List of Figures

List of Tables

1. Introduction

1.1 The Skarv field

The Skarv field is operated by BP and is located in block 6507/2, 6507/3, 6507/5 and 6507/6 in the Norwegian Sea, ca. 200 km west of Sandnessjøen, between the Norne field (35 km to the north) and Heidrun (45 km to the south). The blocks were awarded in production licenses PL212 (1996), PL212B (2002) and PL262 (2002). The water depth in the area is between 350 and 450 m. (BP, 2007)

1.1.1 Skarv/Idun development

The Skarv field was discovered by Amoco (Donatello prospect) with the rig “Mærsk Jutlander” in 1998. Since then, several more successful wells have been drilled. The wells in block 6507/5 have primarily targeted the Garn reservoir of the Skarv segments, while wells in block 6507/5-3 targeted the shallower Cretaceous of the Snadd segment.
The Plan for Development and Operation (PDO) was submitted to the Norwegian Authorities 29th of June 2007 and the development was approved by the Norwegian Storting 18th of December 2007. There will be a joint development of the 6507/5-1 Skarv and 6507/3-3 Idun deposits. The 6507/5-3 Snadd deposit is part of Skarv, but is presently not included in the development. The Skarv Idun Development consists of the Skarv field (oil and gas-condensate field, ca. 12 km end to end), and the neighboring Idun gas field (Statoil operated). The Skarv Idun Development is based on simultaneous oil and gas development utilizing a geostationary, turret moored FPSO with oil offloading to shuttle tankers, and gas export via the ÅTS gas pipeline (Gassled Zone B) to Kårstø, and a subsea arrangement of subsea wells, templates and flow lines. (BP, 2007)
The FPSO will be sized with the following capacities; oil production 85 000 BPD, water production 20 000 BPD, gas production 670 MMscfd and gas export of 650 MMscfd. The development is based on high rate oil and gas producing wells (deviated/horizontal) with sand control completions. Pressure support for oil depletion will be provided by high rate gas injection wells. Gas injection is preferred over water injection as it offers improved hydrocarbon recovery, better economy, and poses less risk to lifecycle well operability. The selected design life for the Skarv Idun facilities is 25 years. (BP, 2007)

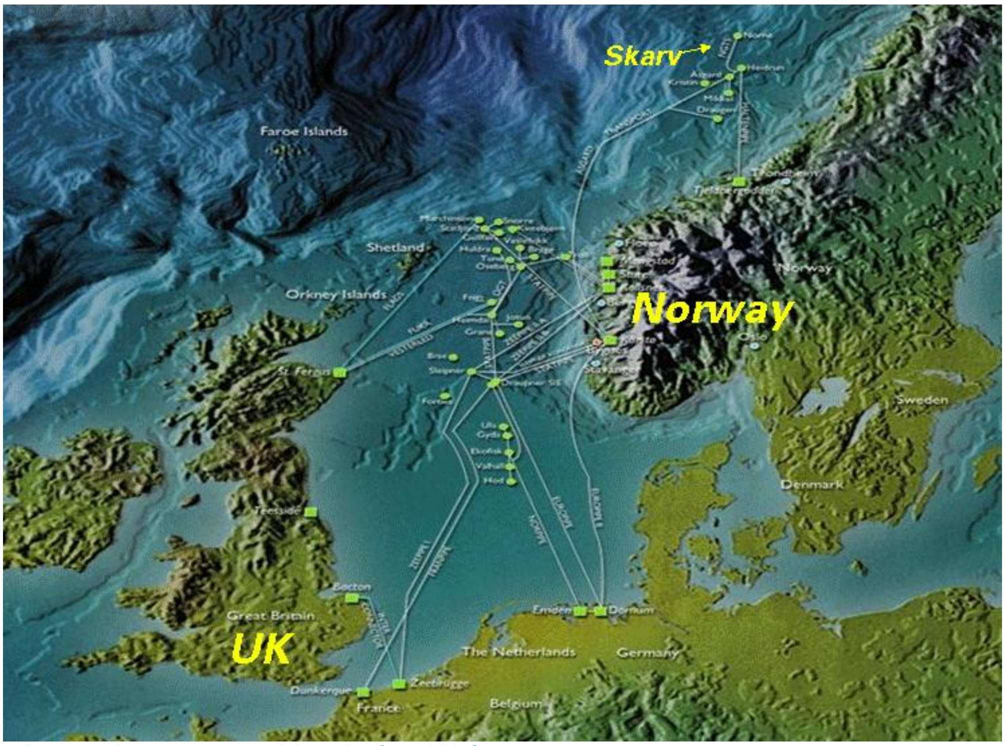


FIGURE 1: SKARV FIELD LOCATION (BP, 2007)

1.1.2 Reservoir description

The Skarv Idun Development consists of 3 fault segments (A, B and C) on Skarv and Idun field. An overview of the layout of the Skarv Idun Development is given in Figure 2.1 below. The reservoir units are the Garn, Ile and Tilje formations, with the main reservoir unit being the high quality Garn formation. Fault segment A contains gas condensate in the Garn and Ile formations with oil and gas in the underlying Tilje formation. Fault segments B and C contain oil with associated gas caps. The gas-oil contact in the B fault segment is unknown, as is the oil-water contact in the C Fault Segment. (BP, 2007)

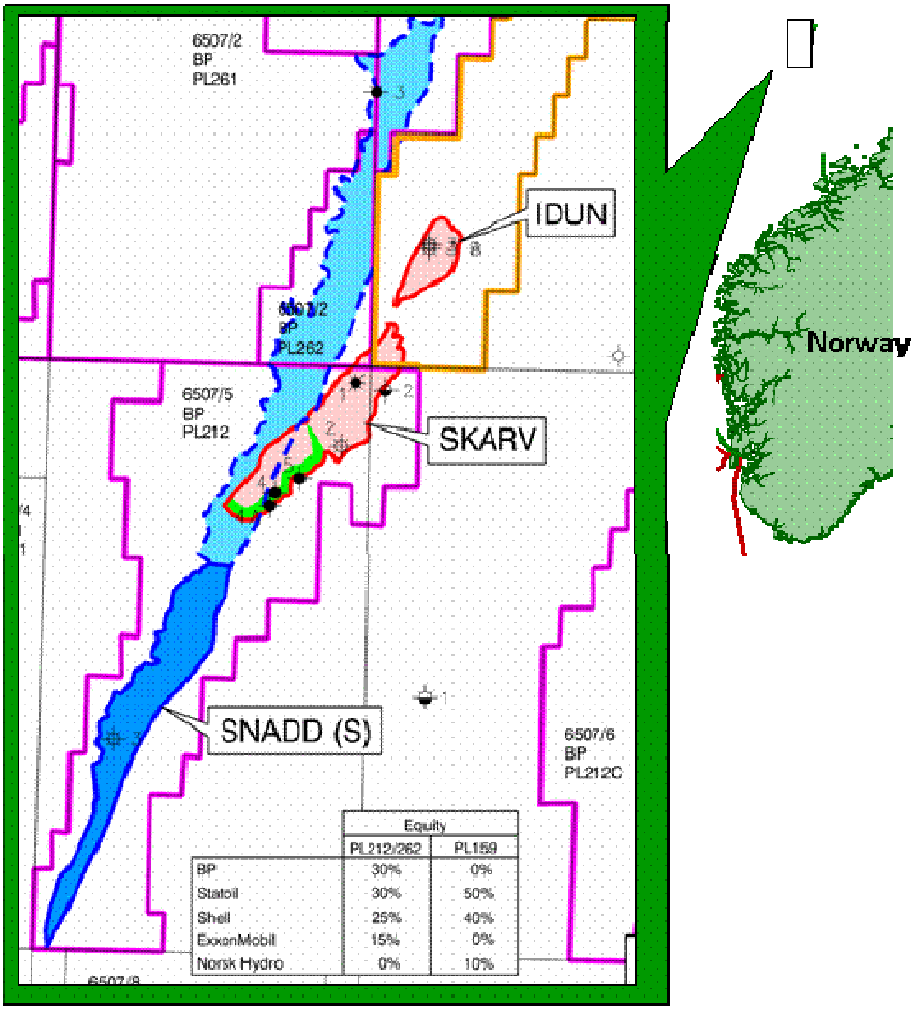


FIGURE 2: SKARV IDUN AREA OVERVIEW (BP, 2007)

In Figure 3 a schematic cross section of the Skarv Idun Development is shown with the previous drilled exploration/appraisal wells. The Skarv Idun Development will from this point be addressed as Skarv.

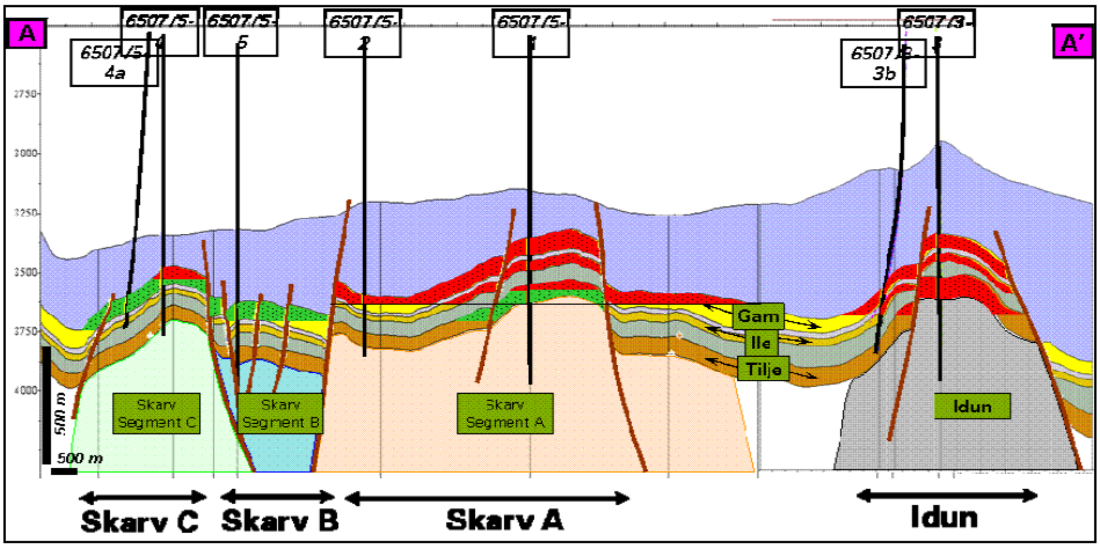


FIGURE 3: SCHEMATIC CROSS SECTION OF THE SKARV IDUN DEVELOPMENT (BP, 2007)

1.1.3 Drainage strategy

Garn is produced without pressure support and will deplete through time while Tilje is being pressure supported by gas injection and the initial reservoir pressure is maintained. (BP, 2007)

1.1.4 Pressure regime

The pore pressure prognosis used for the casing design is based on the generic 5-1 well: Over-pressure is initiated close to the top of the Kai Fm and increases until Nise Fm. This over-pressure is associated with smectitic and illitic clays in the lower Tertiary. Over-pressure gradually reduces down through the Nise Fm and then more dramatically through the Kvitnos Fm to the Top Lysing Fm, associated with breakdown of smectite and the initiation of quartz cementation. Over-pressure begins to ramp-up again through the underlying Lange Fm to a maximum in top Melke Fm. This interval contains numerous porous and permeable sandstones, possibly associated with proximity of the mature Spekk. (BP, 2007)

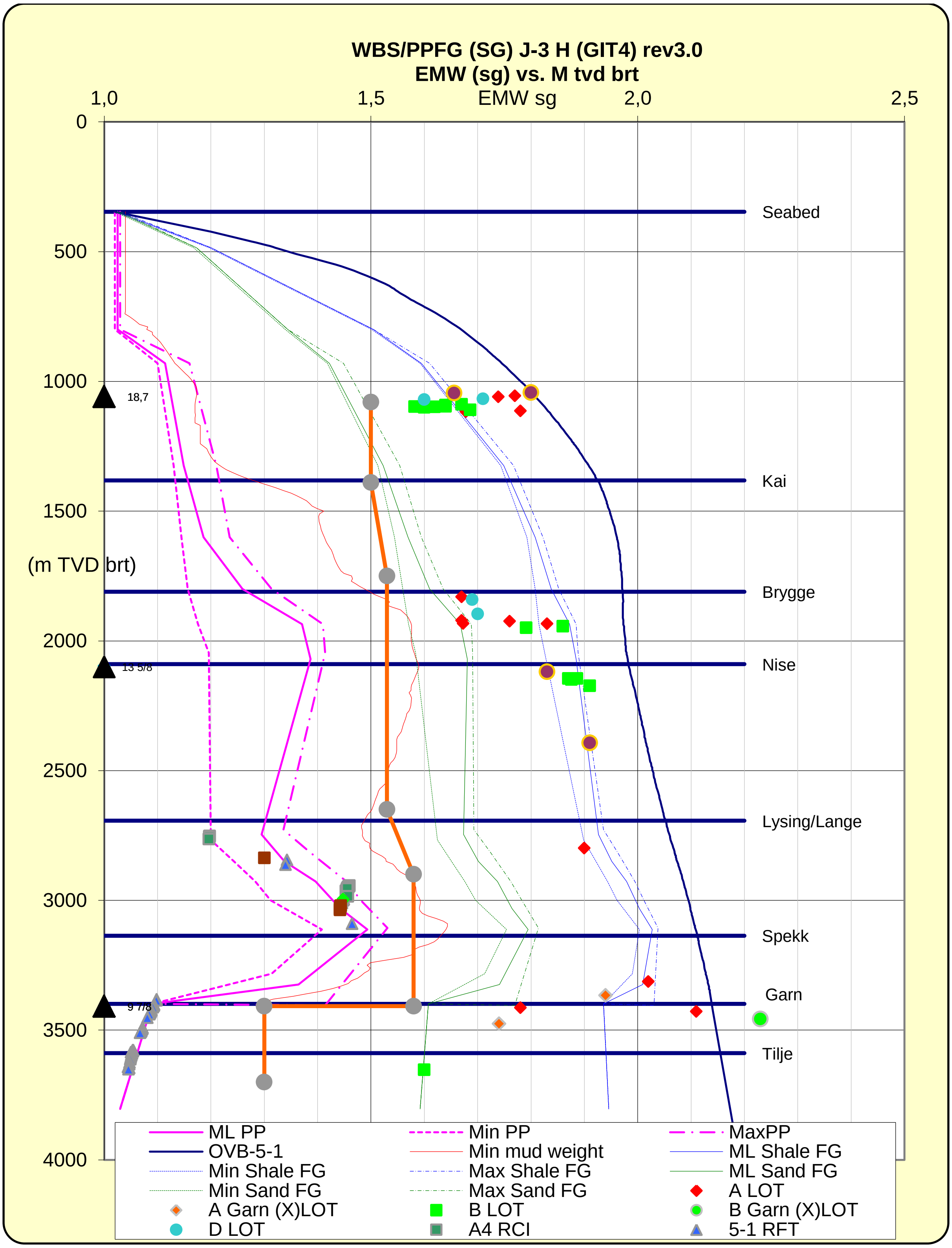


FIGURE 4: SKARV PORE PRESSURE PREDICTION RESULTS (DUNCAN, 2009)

1.2 Drilling and completion strategy

1.2.1 Well Design and integrity

The following design criteria's have been established for Skarv and is taken from "Skarv basis of design" (BP, 2011), which is used as the master document for all well activity on Skarv:

- Design life up to 25 years (life of field).
- Well barriers shall be considered in initial phase for all phases including; drilling, completion, operation, sidetrack, temporary or final abandonment, also for other hydrocarbon filled zones such as Lysing/Lange/Gråsel.
- Preferably develop upper completion designs along a mono-bore philosophy.
- All well types will require some intervention (mechanical interventions, sand control interventions, scale treatments, hydrate incidents, unplanned sidetracks, zone isolation, PLT to TD, and insert safety-valve installation capability).
- Well design needs to take into consideration or be flexible for changes in well status (e.g. well status may change through the life of the well).
- Well design is required to address future infill well needs (e.g. sidetracking).
- Application of active and passive down hole flow control.

1.2.2 Completion

While the target for the completion is the Tilje formation, the 9-7/8" casing will be set just into the Garn formation. The reservoir section will then be drilled through Garn, Ile and Tilje Fm. Lower Completion will consist of blank pipe sections, swell packers and screens to isolate the Garn and Ile Fm while Tilje is being produced or injected into. Tilje will be pressure supported by gas injection but the completion is similar for both producers and injectors. A typical well will consist of 6-5/8" blank pipe which will straddle Garn, 6-5/8" swell packers will straddle the Not shale, 6-5/8" blank pipe will straddle Ile, 6-5/8" swell packers will straddle the Ror shale, and 6-5/8" BakerWrap XP 200 micron screens will be placed across the Tilje. (BP, 2012)

The total length of swell packers, blank pipe and 200 micron screens across the above interval is expected to be +/- 340m. Of this, approximately 115m across the Tilje will contain screens for gas injection. (BP, 2012)

Top of cement is approximately 1075 m above the 9 7/8" casing shoe at 3825 mMD RKB / 3363 m TVD RKB. Planned setting depth of the screen hanger is at 3720 mMD RKB (±105 m above casing shoe) in an area with good cement. (BP, 2012)

The completion will be equipped with 7" 32# 13Cr L-80 production tubing, seal stem (without seals), production packer, Down Hole Pressure and Temperature Gauges (DHPTG's) and a Tubing Retrievable Surface Controlled Subsurface Safety Valve (TRSCSSV). (BP, 2012)

A detailed overview is presented in the schematic in Figure 5 below;

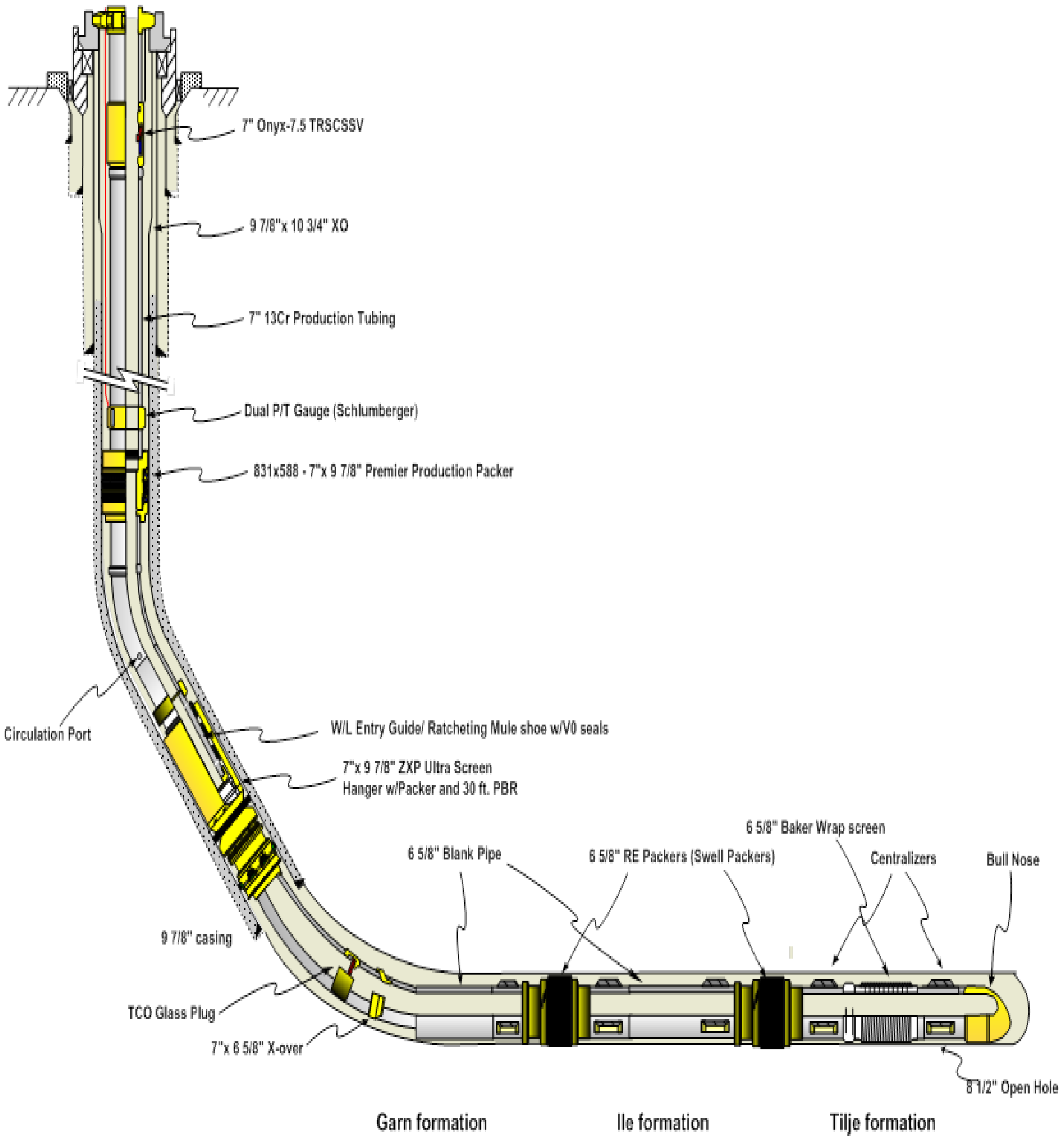


FIGURE 5: COMPLETION SCHEMATIC. (BP 2012)

1.3 Drilling challenges

Above Garn is a high pressure zone, which requires a 1.59sg mud to be drilled. Garn has proven to be a strong formation with LOT's of +/- 2.00 sg and can be drilled with such high overbalance. The drilling program up until now have included drilling the high pressure zone and either set the 9 7/8" casing into top Garn or drill through the sands and set the 9 7/8" shoe in top Tilje. The 9 7/8" casing is installed through a 12 ¼" hole which is drilled with 1.59sg mud. Out of the 9 7/8"shoe, an 8 ½" hole is drilled with 1.30sg mud. The 8 ½" hole is left openhole and swellable packers and blank pipe is used as zonal isolation between the reservoirs. This has been a success, except for some differential sticking issues as a result of this large overbalance. (BP, 2011)

In the future however, Garn will deplete naturally as it is being produced without pressure support and the large overbalance used when drilling will accelerate the diff stick and well stability problems and it is believed this cannot be done. The lower Tilje section is being pressure supported by gas injection and the reservoir pressure will remain somehow constant. Garn will deplete faster than Tilje due to better porosity and pressure support in Tilje. This leads to Tilje having higher pressure than Garn, which can lead to crossflow from Tilje into Garn while drilling Tilje. (BP, 2011)

At this stage BP must drill through a depleted sand layer to reach the Tilje formation which leads to possible loss of drilling window with both reservoirs exposed. This could lead to borehole collapse, kick scenarios, lost circulation and cross flow from Tilje into Garn.
Due to these anticipated problems, the reservoir sections cannot be drilled as one section and in the fashion of conventional casing design, this would normally mean that a 7" liner must be installed between Garn and Tilje and the open hole section drilled with a 6" or 6 ½" bit with a underreamer as a solution. There is a lower reliability on slim hole equipment as well as higher pump pressure and higher ECD while drilling. The completion equipment will need to have a smaller dimension and there will be a higher pressure during the gravel pack operation, which will shorten the max well length that can be drilled through the Tilje reservoir. If the wanted rate of production is to be maintained and the completion designed for this wells is still to be installed, the open hole section needs to be 8 ½ ". Installing a 7" liner between Garn and Tilje means the opportunity to have an 8 ½" hole is lost. (BP 2011)

1.4 Casing design

By installing an expandable liner, hopefully the ID will be maintained and the sands can be drilled with a lower mud weight minimizing diff stick and wellbore stability and wellbore control issues.

Safety dictates that the wellbore pressure must be maintained between the naturally occurring pressure from the formation fluid and the maximum wellbore pressure that the formation can withstand without fracture.
"The density of the drilling fluid must be sufficient to maintain the wellbore pressure above the formation pore pressure to prevent flow of fluids from permeable zones into the well. However, since the wellbore pressure must be maintained below the pressure that will cause fracture in the more shallow, relatively weak , exposed formation just below the casing seat, there is a maximum drilling fluid density that can be tolerated. This means that there is a maximum depth which the well can be drilled safely without cementing another casing string the well."
(Bourgoyne Jr, Chenevert et al. 1986)

After each casing string is cemented in place, a pressure test called a leak-off test I used to verify that the casing cement, and the formation below the casing seat can withstand the wellbore pressure required to safely to the next depth at which casing will be set. The test is performed by closing off the well at surface with a BOP and pump into the closed well at a constant rate until the test pressure is reached or until the well begins to fracture. (Bourgoyne Jr, Chenevert et al. 1986)

1.5 Expandable technology

In the 1980's, the oil industry took a large step in development by the introduction of long reach- and HP/HT wells. This meant drilling through troubled zones and exposing the wells to large forces. Several casing strings were needed for these long wells to mitigate trouble-zones that come with drilling longer and deeper. The need for more casing strings made a gigantic top hole and the casing costs for a well increased dramatically. The casing was a limiting factor. Conventional casing design was also a limiting factor for HP/HT wells, due to the need for many casing strings resulting in a reservoir section too narrow to produce economically or too small to install conventional casing and completion. In the oil industry, tailor-made is expensive. To maintain the economical aspect of well drilling, the operators saw a need for a solution that could limit the use of several tubulars.

The ideal well in a casing design aspect is the so called monobore well with one hole size from top to bottom. This would reduce drilling cost dramatically, the top hole would be “small” and the bottom hole “large”. A monobore would give us diameter efficiency on bottom and cost efficiency at top and we could “drill as far as we wanted”.

As a result of this demand for development in tubular technology the expandable tubular was born. Expandable tubulars is today an accepted, but still in its early development,- tool in the casing design toolbox. It is a step towards the monobore well, in the meantime it has proved to be an alternative solution for curing wellbore stability problems, patch casing leaks and perforations and mitigating diameter losses.

The use of expandable pipe is not new technology. Various industries have utilized expanded pipe for many years. In fact, The idea, borne of necessity was utilised by the Russian oil and gas industry and by the early 1990’s over 700 applications had been recorded in the Former Soviet Union in areas such as shutting off thief zones. (Benzie, Burge et al.2000)

1.5.1 The history of expandable liner

The first attempt to cope with these problems was to line sections of the well temporary with cement while drilling through troubled zones. The idea was successful, but the cement cracked and crumbled when drilling the next section due to vibration from the drill string. As a solution, synthetic fibers were added to the cement. The cement still cracked, but the fibers held the cement together and increased the isolation ability. It was a great solution for temporary lining of the borehole wall. Fiber-cement was developed as a high strength material to line a borehole wall where additional strength was needed to seal off troubled zones without reducing the ID of the borehole. The fiber-cement system was based on synthetic fibers added to Portland cement for strength addition and was used in the industry with success. (van Vliet, van Kleef et al. 1995)

However, the high requirements for HP/HT wells rouse questions if the fiber-cement could be made strong enough to withstand the excessive loads expected in these wells and doubts about the fiber-cement’s robustness against drilling wear/impact forces was questioned. As a result, Royal Dutch Shell started testing the next generation borehole lining system where the fiber-cement was reinforcement by a steel lining, the Alternative Borehole Linings (ABL). The fiber-cement would still act as the sealing element but the steel would give it additional wear and impact resistance. (Stewart, Gill et al. 1996)

This development saw the light for the first time at the Shell research center in Rijswijk, who’s researchers developed the ABL borehole lining system. The initiative was driven by a researcher from the automotive industry with a keen understanding of materials and metal-forming processes. The main driver for this initiative was both to cope with the high forces in HP/HT wells and an attempt to reduce the telescopic effect. By lining the borehole wall with steel tubular reinforced fiber-cement, the need for intermediate casing string could be eliminated and thereby enabling drilling longer hole sections resulting in cost reduction for drilling and casing a well. A mathematical model was developed by Shell to comply with required burst and collapse resistance and the ABL-system could be engineered to suit the load conditions in the well. Leak off tests and yield test proved that ABL had a much higher loading resistance than fiber-cement alone. (Stewart , Gill et al. 1996)

This new development was the start of the expandable tubular technology in the oil industry. As the steel lining, an Expandable Slotted Tubular (EST) was chosen. The EST is a pipe with staggered, overlapping axial slots which allow the pipe to be more easily radially expanded than solid tube. The EST could theoretically be expanded several times its ID. Expansion was achieved by pushing a conical mandrel through the EST. (Stewart , Gill et al. 1996)

FIGURE 6: DRILLED OUT SECTION OF EST IN FIBER CEMENT (STEWART , GILL ET AL. 1996)

Several yard tests and field trials were performed by Shell. Automotive steel pipe was expanded 22% from an original ID of 4% on welded pipe joints. The concept was in its simplest form, cold working steel down hole in situ. A mandrel or pig was used to permanently deform the pipe. The first EST was designed and tested to be installed through an 8.5” drift casing. The open hole section was under reamed to 10” and then the EST was expanded in the wellbore to provide an internal drift diameter of 8.5”. A 6.6” OD and 0.275# WT EST was found to provide the necessary expansion behavior to ensure minimum cement sheet between the expanded EST and borehole of 0.6-1.6” and internal drift id of 8.5”.
The yard trial confirmed successfully the hydraulic sealing capability and the system was tested further in 3 field trials. The hole section where the EST was to be installed was drilled out and under reamed to enable expansion. The EST was run on drill pipe and had an expandable shoe. At the time, expandable connections, was not yet developed and the parts were welded together on site. The EST was expanded in compression. The cement was balanced, left for setting in 24h after expansion and then drilled out. (Stewart , Gill et al. 1996)

Early testing showed that the expansion process increases the ultimate tensile strength, elongation decreases. Expansion changes the Charpy impact toughness of the expandable tubular material. Expansion decreases the collapse rating, probably due to Bauschinger effect, which is a phenomenon that occurs when plastic flow in one direction lowers the applied stress in the other direction. Early test data for grade L80 show indicate that , if pre -and post data dimensions are the same, collapse resistance should decrease by 30% as a result of direct expansion. The expansion process appears to have no detrimental effects in burst strength.

The EST was cemented, expanded, drilled out and successfully pressure tested and following the technology was adopted by the commercial industry and the expandable liner was born. In the US, the use of solid expandable casing began in December 1998, with the formation of Enventure Global Technology, a joint venture between Shell Technology Ventures and Halliburton Energy . (Benzie, Burge et al. 2006)

The first commercial installation was performed on Thanksgiving Day 1999 for Chevron on an offshore Louisiana well. The objective was to case off a high pressure zone in order to drill through a lower partially depleted zone. A 985' 7-5/8" x 9-5/8" open hole liner was run to 13,131', cemented and successfully expanded. Expansion pressures averaged 4,000 psi and the expansion process took about 4-1/2 hrs. As a result of this first job, the float shoe assembly was revised for more efficient drill out and expansion pump rates were optimized. The first horizontal expansion was performed for Shell Nigeria. After initial problems resulted in some design modifications, the 1,659' of liner was expanded in October of 2001. (Stewart , Gill et al. 1996)

Filippov, A., Mack, R. et al. concluded in 1999 that Expandable technology could be a god tool to reduce costs and enable drilling of previous uneconomically prospects by the use of openhole expandable drill liner. It could be a good tool for coping with lost circulation and trouble zones and that by the use of the technology, ultradeep wells could be completed with initiating with smaller tubulars and hence reducing top facilities.

2. Theory

2.1 Solid Mechanics

The key elements in solid mechanics are the concept of stress and strain. Stress is the internal resistance that acts to counteract imposed external forces on the solid. Strain is the resulting deformation of the object by the external forces. There will thus always be a relation between the concepts of stress and strain. (Aadnøy, B.S., Looyeh, R. 2011)

2.1.1 Stress

Force applied to a solid is referred to as stress. Stress is defined as a force, *F*, acting over an area of a cross section, *A*. From Figure 7 and EQ.1 the stress acting on the surface A' is grater in magnitude than the stress acting on surface A. (Aadnøy, B.S., Looyeh, R. 2011)

$$\boldsymbol{\sigma} = \frac{\boldsymbol{F}}{\boldsymbol{A}} \qquad \text{EQ. 1}$$

$\sigma = Stress$ [Pa or psi], $F = Applied\ force$ [N or lbf], $A = Cross\ sectional\ area$ [m^2 or in^2)

Stress is independent of the shape of the body but not on its orientation. (Aadnøy, B.S., Looyeh, R. 2011)

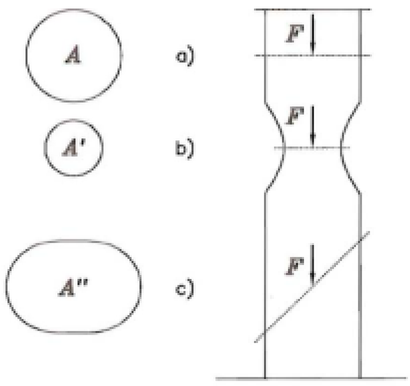


FIGURE 7: STRESS APPLIED TO STEEL TUBULAR WITH THREE DIFFERENT CROSS SECTION AREAS. (FJÆR, E., HOLT, R.M. ET AL. 2008)

Further the cross sectional area can be divided into infinite number of subsections ΔA. The force acting on ΔA is then referred to as ΔF. If we consider a subsection *i* with a mid-point *P*, the local stress at point *P* is defined as*:*

$$\boldsymbol{\sigma} = \lim_{\Delta A_i \to 0} \frac{\Delta F_i}{\Delta A_i} \qquad \text{EQ. 2}$$

The stress acts through the surface and is dependent on the cross sections orientation. Stress can be decomposed into normal stress and shear stress, where normal stress is the stress acting perpendicular to the surface and the shear stress the stress component acting along the surface. Normal stress may result in tensile or compressive failure, while the shear stress leads to the material shearing or slipping along planes. (Aadnøy, B.S., Looyeh, R. 2011)

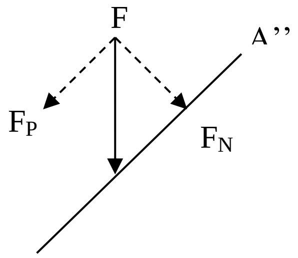


FIGURE 8: STRESS DECOMPOSED INTO NORMAL– AND SHEAR STRESS. (FJÆR, E., HOLT, R.M. ET AL. 2008)

The physical relation is thus:

Normal stress:

$$\boldsymbol{\sigma} = \frac{F_N}{A''} \qquad \text{EQ. 3}$$

Shear stress

$$\boldsymbol{\tau} = \frac{F_P}{A''} \qquad \text{EQ. 3}$$

For further readings about stress decomposition, please refer to the book by Aadnøy and Looyeh (2011).

2.1.1.1 The stress tensor

To give a complete description of the stress state at point *P*, the stresses related to the surfaces oriented in three orthogonal directions must be described. Stresses related to the normal axis to the x-axis is denoted σ_x, τ_{xy} and τ_{xz}, representing the normal stress, the shear stress retaled to a force in y-direction, and the shear stress related to a force in the z –direction respectively. Similary, the streses related to a surface normal to the y-axis are denoted σ_y, τ_{yx} and τ_{yz}, and stresses normal to the z-axis are denoted σ_z, τ_{zx} and τ_{zy}. There are thus nine stress components that make up the stress tensor. (Fjær, E., Holt, R.M. et al. 2008)

$$\begin{pmatrix} \boldsymbol{\sigma_x} & \boldsymbol{\tau_{xy}} & \boldsymbol{\tau_{xz}} \\ \boldsymbol{\tau_{yx}} & \boldsymbol{\sigma_y} & \boldsymbol{\tau_{yz}} \\ \boldsymbol{\tau_{zx}} & \boldsymbol{\tau_{zy}} & \boldsymbol{\sigma_z} \end{pmatrix} \quad \text{EQ. 4}$$

This also applies to principle stress in three dimensions.

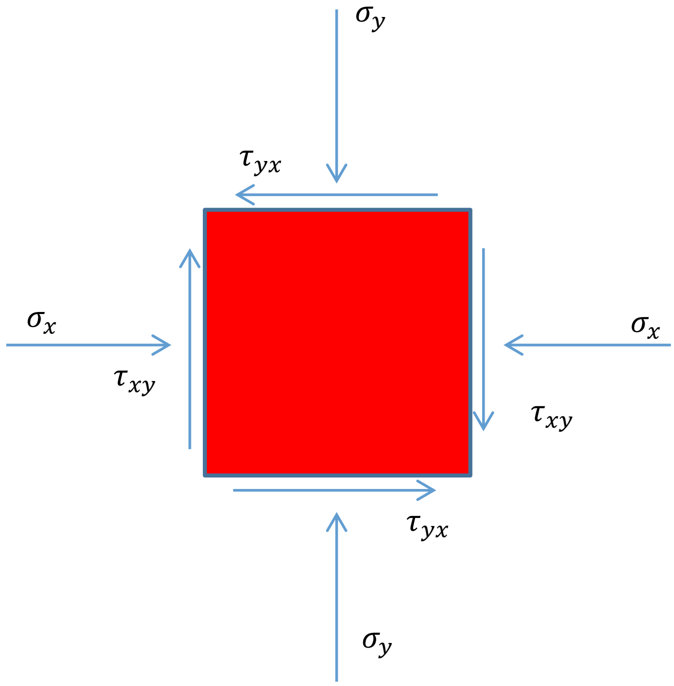


FIGURE 9: STRESS COMPONENTS IN TWO DIMENTIONS.(FJÆR, E., HOLT, R.M. ET AL. 2008)

2.1.1.2 Principal stress

For special orientations of the coordinate system, the stress tensor has a particularly simple form. Consider the normal (σ) and the shear (τ) stresses at a surface oriented normal to a general direction θ in the xy-plane. With proper choice of θ, it is possible to obtain τ = 0. The equation has two solutions, and these two solutions correspond to two directions for which the shear stress τ vanishes. (Fjær, E., Holt, R.M. et al. 2008).
These two directions are called the principle axis of stress and the corresponding normal stresses are called the principle stress and are given by:

$$\sigma_1 = \frac{1}{2}\left(\sigma_x + \sigma_y\right) + \sqrt{\tau_{xy}^2 + \frac{1}{4}(\sigma_x - \sigma_y)^2} \quad \text{EQ. 5}$$

$$\sigma_2 = \frac{1}{2}\left(\sigma_x + \sigma_y\right) + \sqrt{\tau_{xy}^2 + \frac{1}{4}(\sigma_x - \sigma_y)^2} \quad \text{EQ. 6}$$

2.1.2 Strength

The stress level at which a rock typically fails is commonly called the strength of the material, in other words, the ability of a material to resist the application of a load without failure. Strength is the driving parameter for material selection for wellbore tubular, when these are exposed to loads through the installation and during the lifetime of the well. (Fjær, E., Holt, R.M. et al. 2008)

2.1.3 Strain

When acted on by an external force a particle will not only experience stress, but the particles position will be shifted. This shift in position will result in a displacement of the particle and a deformation of the material. This displacement is referred to as strain. The material will deform in x and y direction simultaneously if free to move in both directions and strain is decomposed into two components ε_y and ε_x, which represents displacement in y and x direction respectively.

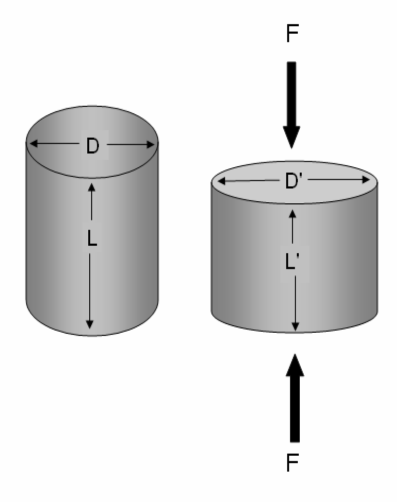
For a steel tubular with diameter *D* and length *L*, strain in x and y direction is referred to as elongating and lateral strain and are defined as respectively (Fjær, E., Holt, R.M. et al. 2008):

$$\varepsilon_x = \frac{L - L'}{L} \quad \text{EQ. 7}$$

$$\varepsilon_y = \frac{D - D'}{D} \quad \text{EQ. 8}$$

This response is shown in Figure 10.

L>L' and D'>D.



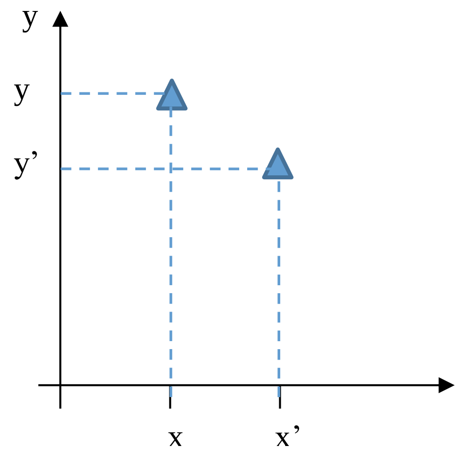


FIGURE 10: ELONGATION AND LATERAL DISPLACEMENT OF A SAMPLE MATERIAL. (FJÆR, E., HOLT, R.M. ET AL. 2008)

The ratio between the elongation and lateral displacement can be written as (Fjær, E., Holt, R.M. et al. 2008):

$$\nu = -\frac{\varepsilon_y}{\varepsilon_x} \qquad \text{EQ. 9}$$

The relation is called $Poisson's\ ratio$, which is a measure of lateral expansion relative to longitudinal contraction. In Table 1 below are some typical values listed;

TABLE 1: POISSON'S RATIO VALUES NORT SEA RESERVOIR ROCK AND STEEL

Material	Poisson's ratio*
Sandstone	0 - 0.45
Shale	0 - 0.30
High porosity chalk	0.05 - 0.35
Low porosity chalk	0.05-0.30
Steel	0.28

*Fjær, E., Holt, R.M. et al. 2008

Strain can also be expressed as the reduction of the samples volume and is then referred to as volumetric strain. The volumetric strain is a product of reduction of the volume in both x, y and z direction. (Fjær, E., Holt, R.M. et al. 2008)

$$\varepsilon_v = \varepsilon_x + \varepsilon_y + \varepsilon_z \qquad \text{EQ. 10}$$

2.1.4 Stress/strain relation

There will always be a relationship between the applied stress and the resulting strain. The simplest relation is when there is a linear relationship between the two. This occurs when the loading is elastic. When loaded elastically, the material returns to its initial form after unloading. (Fjær, E., Holt, R.M. et al. 2008)

Consider a specimen of initial length L in the x-direction in a plane. When applied a force, the sample length changes to L' as explained in section 2.1.3. The applied stress is then $\sigma_x = F/A$. The corresponding elongation is $\varepsilon_x = (L - L')/L$ according to EQ 1 and EQ 8. If considering the relation to behave linearly, the relation is (Fjær, E., Holt, R.M. et al. 2008):

$$\boldsymbol{\varepsilon_x = \frac{1}{E}\sigma_x} \qquad \text{EQ. 11}$$

This relation is known as $Hooke's\ law$ and the coefficient E is called the Y$oung's\ modulus$ or the $E - modulus$ and is a measure of the samples resistance against compression by uniaxial stress (Fjær, E., Holt, R.M. et al. 2008). In Table 2 below are some relevant values listed:

TABLE 2: YOUNG'S MODULUS VALUES FOR NORTH SEA RESERVOIR ROCK

Material	Young's modulus, E [Gpa]
Sandstone	0.1-30
Shale	0.4-70
High porosity chalk	0.5-5
Low porosity chalk	5-30
Steel	200

*Fjær, E., Holt, R.M. et al. 2008

EQ.12 are defined by a specific state of stress $\sigma_x \neq 0$ and $\sigma_y = \sigma_z = 0$. In general, each component of strain is a linear function of all components off stress.

Isotropic materials are materials whose response is independent of orientation of the applied tress. For these materials the general relation between stress and strain is:

$$\boldsymbol{\sigma_x = (\lambda + 2G)\varepsilon_x + \lambda\varepsilon_y + \, + \lambda\varepsilon_z} \qquad \text{EQ. 12}$$

$$\boldsymbol{\sigma_y = \lambda\varepsilon_x + (\lambda + 2G)\varepsilon_y + \, + \lambda\varepsilon_z} \qquad \text{EQ. 13}$$

$$\boldsymbol{\sigma_y = \lambda\varepsilon_x + + \lambda\varepsilon_y + (\lambda + 2G)\varepsilon_{yz}} \qquad \text{EQ. 14}$$

Where λ and G are elastic modilis, known as $Lamé's\ parametres$. G is also referred to as the shear modulus and is a measure of the materials resistance against shear deformation. (Fjær, E., Holt, R.M. et al. 2008)

A material will commonly only behave elastically if a small amount of force is applied to the material. When the applied force increase, the material will enter a plastic phase where the structure is permanently damaged and the material is no longer able to fully recover to its initial phase. The material is said to behave plastically when the strain no longer returns to zero after the stress is relieved. The transition between the elastic and plastic phase is called the yield point and is identified in the stress-strain diagram as the point which after the stress-strain relationship no longer are linear. If the material is loaded further beyond the yield point, the material will eventually reach its ultimate strength and the tubular will fail. This is shown in Figure11 as the failure point. (Fjær, E., Holt, R.M. et al. 2008)

The different phases and the stress-strain response are shown in Figure 11 below:

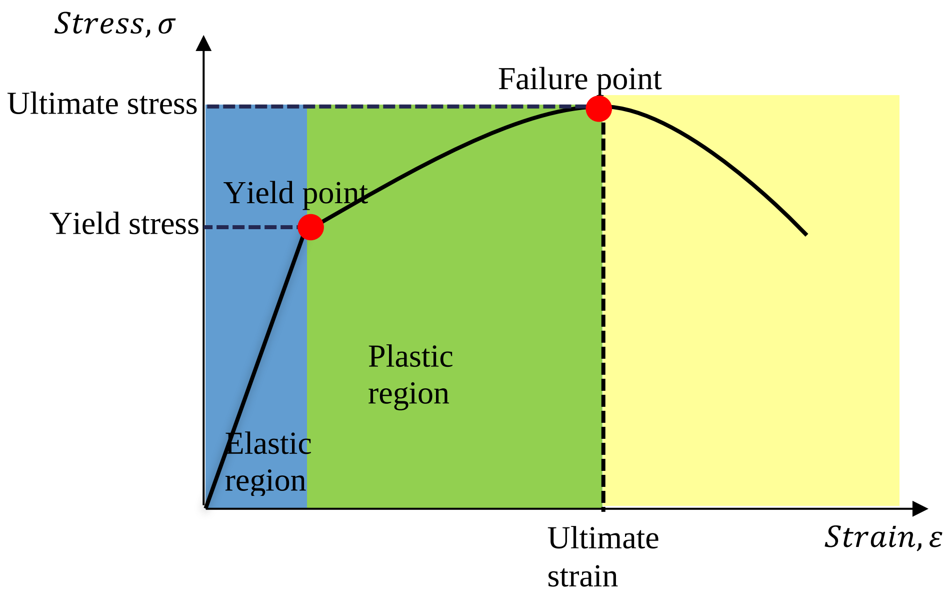


FIGURE 11: STRESS-STRAIN RELATION IN A LINEAR ELASTIC MATERIAL. ((AADNØY, B.S., LOOYEH, R. 2011)

2.1.5 Ductil and brittle

The yield stress/failure stress ratio defines the degree of ductility of the material. L-80 has a ratio about 0.87 (Smith, 1993). For very strong steel the ratio approaches one which means these steel qualities are brittle, meaning they will fail loaded slightly beyond the yield point.

Ductility is the ability of a material to deform easily when a force is applied, or to withstand plastic deformation without rupture. Ductile materials can be deformed more before fracturing than brittle materials. The ductility of a material is dependent on several factors, one being temperature. An increase in temperature increases the ductility, while a decrease in temperature decreases the ductility. Work hardening tends to make metals less ductile more ductile the material is, the more it will neck before fracture. This means that the engineering stress, which is calculated based on the original cross-sectional area on the stress-strain curve, decreases considerably beyond the maximum stress before rupture
The amount of elongation in a tensile test can be used as a measure for the ductility of the material. The final length and the initial length are measured and percent elongation can be calculated. The reduction in cross-sectional area can also be used as a measure for the ductility of the material. The initial area and the area after the tensile test is then measured, and percent reduction in area can be calculated from these measurements. The higher the elongation and area reduction, the more ductile the material is. (Smith, 1993)

2.1.6 Toughness

The toughness describes the way the material reacts under sudden impacts. The modulus of Toughness is a measure of the material's ability to absorb energy before it fractures, and it represents the strain energy per unit volume, which is the strain-energy density in the material at fracture. The strain-energy density is equal to the area under the stress-strain curve from zero to the point of fracture. The larger the modulus of toughness is, the larger the material's ability to absorb energy without fracturing will be. (Bores & Schmidt, 2003)

2.1.7 Hardness

The hardness of a material is the ability to resist plastic deformation, penetration, indentation and scratching. This property is important because the resistance to resist wear and erosion increases with the hardness. The hardness is measured by forcing an indenter into the material's surface. The indenter is made of a material much harder than the material being tested. An empirical hardness number is determined based on the cross-sectional area or depth of the impression. (Bores & Schmidt, 2003)

2.1.8 Work hardening

Polycrystalline metals are composed of a large number of very small units called crystals or grains. These crystals have slip planes on which the resistance to shear stress is relatively small. Under elastic loading, the crystal itself is distorted because of stretching or compressing the atomic bonds. The crystal returns to its undistorted state if the load is removed and there is no permanent deformation. If a load above the yield strength is reached below the recrystallization temperature, the crystals are distorted as before, and in addition, defects in the crystals move in the slip planes. These defects are known as dislocations. When the dislocations move in the slip planes, atomic bonds break. When the load is removed the distorted crystals are recovered, but the movement of the dislocations does not. The result is a permanent deformation. (Bores & Schmidt, 2003)
After the crystals have yielded sufficiently, these crystals will not yield further without an increase in the load. The reason is that the dislocation density increases and the dislocations entangles, thereby making motion of dislocations more difficult. The result is that a higher stress is needed to push ne dislocations through the entanglements. This increase in resistance to deformation that is developed after yielding is known as work hardening or strain hardening. While work hardening increases hardness and tensile strength, it lowers the ductility of the material.l (Smith, 1993)

2.1.9 Cold working

Cold working is by definition a process that alters the shape or size of a metal by plastic deformation. Processes include rolling, drawing, pressing, spinning, extruding and heading, it is carried out below the recrystallization point usually at room temperature. Hardness and tensile strength are increased with the degree of cold work whilst ductility and impact values are lowered. The cold rolling and cold drawing of steel significantly improves surface finish. (About.Com-Metals)

2.1.10 Bauschinger effect

The Bauschinger effect can be explained by considering a specimen loaded in tension in the inelastic range. The tension load is then gradually removed and then the specimen is loaded in compression. In an ideal model, the compressive yield should be equal to the initial yield stress. However, it has been observed that the compressive loading following a tensile unloading from the inelastic region results in a decrease in compressive yield stress. The phenomena occur when plastic flow in one direction lowers the applied stress in the other direction. (Boresi & Schmidt, 2003)

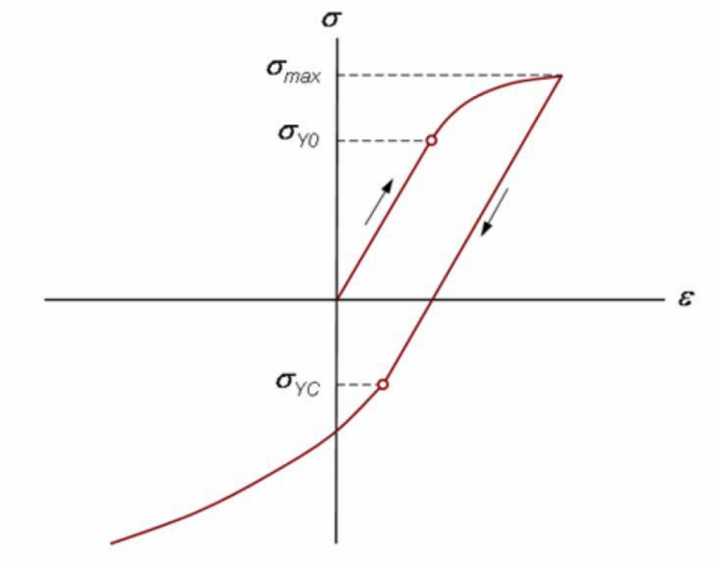


FIGURE 12: BAUSCHINGER EFFECT (RUAN & MAURER, 2005)

The Bauschinger effect is illustrated in Figure 11, where σmax is the maximum stress the material is loaded to in tension, σ_{Y0} is the initial yield stress, and σ_{YC} is the compressive yield stress after the material has been loaded to σmax in tension. The figure shows that the compressive yield stress is smaller after the material has been loaded above the yield stress in tension; however, this phenomenon is usually symmetric. If the material had been loaded in compression above the yield stress and then loaded in tension, the tensional yield stress would have been reduced.(Ruan & Maurer, 2005)

2.1.11 Autofrettage

Cylinders made of a ductile material can be strengthened by introducing beneficial residual stress distributions. Beneficial stress distributions may be introduced into a tubular by exposing it to high internal pressure, such that it is loaded beyond yield and starts to behave plastically. As a result, the load carrying capacity of the tubular is increased due to the beneficial residual stress distribution that remains in the tubular wall when the high pressure is removed.

The residual stress distribution depends on the depth of yielding produced by the internal pressure, the shape of the stress-strain diagram for the material, and the shape of the stress-strain diagram for tensile unloading followed by compression loading (Boresi & Schmidt, 2003, p. 405). If the material is elastic-perfectly plastic, all the increase in load-carrying capacity is because of the beneficial residual stress distribution. However, if the material is a strain-hardening material, a part of the increase in load-carrying capacity is due to strengthening of the material from strain hardening the material. The process of increasing the strength of a cylinder by applying high internal pressure until inelastic deformation to produce a beneficial residual stress distribution is called autofrettage. The beneficial effect of the autofrettage process increases as the inelastic deformation spread through the wall of the cylinder. The inelastic deformation starts at the inner wall and spreads outwards. After the entire wall thickness has been yielded, any further increase in load-carrying capacity resulting from additional inelastic deformation is because of strain hardening (Boresi & Schmidt, 2003).

2.2 Petroleum related rock mechanics

In order to drill and case off a wellbore, the engineers must consider the mechanical properties of the wellbore wall and the formation that are drilled. At large depths the overlying formation induces large weights upon the considered formation applying large stresses to the rock matrix and fluids. When drilling the wellbore, the matrix is removed, disturbing the stress state around the borehole. If these stresses and large forces are not properly considered, it is a risk that the borehole wall will collapse, cave inn or lead to unwanted fluid influx that may cause well control issues.

2.2.1 Porosity

Porosity is defined as the volume of the rocks pores related to the bulk volume. The bulk volume is the rocks total volume of pore volume and the matrix volume. (Fjær, E., Holt, R.M. et al. 2008)

$$\boldsymbol{\varphi = \frac{V_p}{V_b}} \qquad \text{EQ. 15}$$

$$\boldsymbol{V_b = V_p + V_m}{}^{V_b} \qquad \text{EQ. 16}$$

$\varphi = Porosity, V_p = Pore\ voulme, V_b = Bulk\ volume$

2.2.2 Permeability

Permeability of a porous medium rock is the capacity to transmit fluids through its network of interconnected pores and is a thus a measure of how easily the formation fluid can flow through the reservoir. (Fjær, E., Holt, R.M. et al. 2008)

2.2.3 Poromechanics

When the properties of the void space affect the rocks behavior, the pore pressure is an important parameter in any rock mechanical study of a porous, fluid filled rock system. As force applied to solids is referred to as stress, force in fluids is referred to as pressure. As saturated sediments are buried, the overburden pressure increase and if the pore fluid is unable to emigrate from the pore structure the pressure inside the pores will increase. This pressure is referred to as pore pressure. This can relate to the situation in a hydrocarbon reservoir. There are, however several cases where the pore pressure within a zone has a value different from the expected normal pore pressure. The zone is then referred to as abnormally pressurized or over pressured. High pore pressure in a reservoir will make the field more prolific but can also be challenging related to drilling the high pressure zone. (Fjær, E., Holt, R.M. et al. 2008)

In cases of high pore pressure the rock will experience less stress than applied by the force because the stress applied to the rock will be relieved by the pore pressure when the pore pressure acts the opposite way of the overburden pressure. Pore pressure is therefore an important parameter in determination of stress and thus the compaction behavior of the matrix. The stress actually experienced by the rock is defined as effective stress and is the actual stress the matrix is exposed to by the difference between the applied load and the pore pressure. (Fjær, E., Holt, R.M. et al. 2008)

2.3 Pressure

Force on casing and liner in a well is mainly pressure. There are two main pressure limits that must be considered; the pore pressure and the fracture pressure.
In petroleum related rock mechanics we talk about overburden and fracture stresses and pore pressure when these are the forces that are important to have control over during drilling.

2.3.1 Overburden pressure

The rock at any given depth must carry the weight of the overlying formations. The vertical stress at the bottom of a uniform column of height Z is $\sigma_v = \rho g z.$, where ρ is the density of the material, and g is the acceleration of gravity. If the density varies with depth, the vertical stress at depth *D* becomes:

$$\boldsymbol{\sigma_v = \int_0^D \rho(z) g \, dz} \qquad \text{EQ. 17}$$

z is vertical and $z = 0$ is defined as the earth surface (Fjær, E., Holt, R.M. et al. 2008)

2.3.2 Pore pressure

The rocks pores are fluid filled and the pore pressure at a given depth is the hydrostatic pressure from a seawater column from seabed or earth surface to any given depth. This is referred to as normal pore pressure

The normal pore pressure is defined by:

$$\boldsymbol{p_{fn} = \int_0^D \rho_f(z) g \, dz} \qquad \text{EQ. 18}$$

Where, p_{fn} is the normal pore pressure, g = gravity, D =Depth and z = the hight of the hydrostatic column. (Fjær, E., Holt, R.M. et al. 2008)

If the formation pores are filled with fluids that are not free to move as in a reservoir, the pores may have a higher pressure than exerted by the hydrostatic column and the formation is said to have an abnormal pore pressure. The fluid will carry part of the total stress imposed on the formation by the overburden, relieving the rock matrix from the part of the load. Terzaghi defines the effective stress, which is the stress actual seen by the matrix, and is equal to the total stress σ minus the pore pressure P_0 and is denoted σ'.

$$\boldsymbol{\sigma' = \sigma - P_0} \qquad \text{EQ. 19}$$

The effective vertical stress is then:

$$\boldsymbol{\sigma'_v = \sigma_v - P_0} \qquad \text{EQ. 20}$$

Abnormal pore pressures make reservoirs more prolific, but it may at the same time impose a potential drilling hazard. (Fjær, E., Holt, R.M. et al. 2008)

2.3.3 Fracture pressure and stresses around boreholes

If the fluid pressure within the rock exceeds the smallest principle stress plus the tensile strength of the rock, tensile failure or splitting of the rock will occur. This happens if the fluid pressure in the borehole is large enough for the smallest principle stress, $\sigma_{h,min}$, to become tensile. If the wellbore pressure is maintained, the formation will split and fractures will propagate in the direction of the smallest principle stress in the formation. (Fjær, E., Holt, R.M. et al. 2008)

Horizontal effective stress is the total horizontal stress minus the pore pressure.

$$\boldsymbol{\sigma'_v = \sigma_v - P_f} \qquad \text{EQ. 21}$$

In a rock, the ability to resist shear stress causes the horizontal stress σ_h in general to be different from the vertical stress. In terms of effective stresses we can write

$$\boldsymbol{\sigma'_h = K\,\sigma'_v} \qquad \text{EQ. 22}$$

Where K is the ratio between the effective horizontal stresses and the effective vertical stresses;

$$\boldsymbol{K = \left(\frac{\nu}{1-\nu}\right)} \qquad \text{EQ. 23}$$

At shallow depths (0-150m), K values between 1 to 10 can be encountered, while values between 0.2 and 1.5 is more common at larger depths. (Fjær, E., Holt, R.M. et al. 2008)

2.3.4 Pressure gradients

In drilling the determination of the proper mud weight to use in specific drilling operations are crucial for the success of the operation. Mud weigh are determined first off all based on the pressures expected to encounter in the formation around the borehole. To easily compare the mud weigh to the formation pressure, pore pressure, overburden stress, fracture and collapse pressure are converted into pressure gradients. Specific gravity, sg, is used as measurement, which are the fluids density compared to water. This is applicable for steady state situations, in transient situations, such as circulating out a kick, pressures must be used. Conversion between pressure and pressure gradient can be done by using the following equation:

$$[sg] = 0.0981 * D\ [mTVD] * P[bar]$$ EQ. 24

Where D= vertical depth and P = Pressure at depth D. (Fjær, E., Holt, R.M. et al. 2008)

2.3.5 Drilling window

To avoid kick and losses while drilling it is important to keep the mud weight used to drill the section between the formation pore pressure, which if exceeded will induce a kick, and the formation fracture pressure, which if exceeded will fracture the formation and induce losses. Keeping the well pressure between these is balanced drilling, or often referred to as overbalance. The mud weight selection chosen to drill the section must thus lie between the pore and fracture curve in the well. The simplest approach is the *median line principle* suggested by Aadnøy (Aadnøy 2010), which states that the midpoint between the formation fracture pressure and the formation pore pressure, gives the well pressure that is related to the ideal in-situ stresses. Aadnøy claims that the median line pressure is the pressure that less will disturb the borehole wall.

However, this is a simplified model of the active pressures in a wellbore. There are also wellbore stability issues that must be addressed before finding the correct mud weight for drilling the section without well control issues. If the overbalance is too large, i.e. the mud weight is much higher that the pore pressure, differential sticking might occur.

2.3.6 Wellbore stability

Formations at a given depth are exposed to vertical and horizontal compressive stresses and pore pressure. When a hole is drilled, the surrounding rock must carry the load that previously was varied by the removed rock. In a rock that behaves linearly elastic, this leads to a stress concentration near the well. If the rock is sufficiently weak, this stress concentration can lead to failure of the borehole. (Fjær, E., Holt, R.M. et al. 2008)

When drilling, the well is filled with mud. The mud will carry part of the stress concentration thus the mud weight controls the mechanical stability of the borehole. The mud weight can be chosen based on the minimum mud weight equation;

$$\boldsymbol{p_{w,min}} = \frac{\boldsymbol{P_f + \sigma_v + 2\nu(\sigma_H - \sigma_h) - P_f - UCS}}{\boldsymbol{tan^2\beta}}$$ EQ. 25

$$\boldsymbol{\sigma_H = \sigma_h * 1.05}$$ EQ. 26

$$\boldsymbol{UCS = 0.77 * Vp^{2.93}}$$ EQ. 27

$$\boldsymbol{UCS = 1.35 * Vp^{2.6}}$$ EQ. 28

$$\boldsymbol{\beta = 39.9 + 5.5\,Vp}$$ EQ. 29

Where UCS = UnConfined Strain, P_f = fluid pressure (pore pressure), σ_h = the fracture gradient, β = the rocks failure angle and Vp = p-wave velocity

2.3.7 Depletion

As the hydrocarbons are produced, the pressure in the hydrocarbon bearing formation, the reservoir, the pore pressure, is reduced. This is called depletion. As the pore pressure drops, so does the stresses.

The effective vertical stress increases by the amount the pore pressure has decreased. The most interesting from a driller's point of view is the change in the horizontal stress which is the stress that affects the fracture pressure.

Several stacked layer fields, like Skarv, have motivated extensive studies on the effect of depletion on future pressure and drillability. (Aadnøy & Looyeh 2009)

2.3.8 Uniaxial Strain Model (USM)

Overburden stress is the vertical stress in a basin. The weight of the overburden is typically the largest source of stress in most sedimentary basins. The weight of the overburden creates vertical stress, and is called gravitational loading. Horizontal stress are generated as the sediments tries to deform sideways in response to the vertical stress but is constrained by the surrounding material. In a graben, like the North Sea basin, the sides of the basin can be considered fixed boundary conditions. When the sediments are constrained at both sides a uniaxial –strain condition exists. Uniaxial strain literally means that strain is able to occur only along one axis - the vertical axis. This is the condition for the Uniaxial strain model (USM); traditionally one of the most commonly used models for estimating in–situ horizontal stress magnitudes in petroleum geomechanics. In this model, the magnitude of the horizontal stress is determined by the elastic properties of the rock, specifically Poisson's ratio. A rock with low Poisson's ratio, when loaded vertically and constrained on both sides, will transfer more load sideways to generate horizontal stress. A material with higher Poisson's ratio will transfer more of the load, generating a higher horizontals tress. Under simple gravitational loading, the vertical stress is a principal stress and it will be in most cases the maximum stress.(Aadnøy, Cooper et al. 2009)

If we also assume that the rock is linear elastic and isotropic, the magnitude of both horizontal stresses can be expressed as a function of vertical stress (the overburden), pore pressure and Poisson's ratio. This however is a very simplified assumption when horizontal strain will occur if the basin boundaries expand or contract. Such movement however would happen over a significant period of time. The USM may therefore be suited to describe relatively small changes in horizontal stress that occur over short periods of time such during reservoir depletion. The USM is a commonly used framework for determining horizontal stress in the petroleum industry. .(Aadnøy, Cooper et al. 2009)

The most common stress regimes are where the three principal stresses remain vertical and horizontal (Aadnøy & Looyeh 2009). Understanding the magnitude of these three principals tresses are crucial for resolving the stresses onto the wellbore wall, where the calculation of the required MW is performed. The rules of thumb to designing the most stable hole trajectory for a given stress regime is to try to minimize the magnitude of stress difference between the two principal stresses acting on the borehole wall. A vertical well will thus experience the least differential stress.

To get an accurate wellbore stability prediction, stress regime and magnitude of the stresses are important. It is the full effective stress tensor and the rock strength that determines the required MW. It is therefore needed to perform a full wellbore stability calculation to find the ideal MW. .(Aadnøy, Cooper et al. 2009)

As hydrocarbons are produced, the pore pressure in the reservoir drops unless there is pressure support. As pore pressure drops, so does the in-situ stresses. The vertical stress is not affected, as the weight of the overburden remains unchanged. From a drilling point of view the response of horizontal stress is of interest because of its effect on FG. .(Aadnøy, Cooper et al. 2009)

During moderate depletion, strains are fairly small and the timeframe is short. Sand reservoirs can also be very isotropic, for this reason assuming linear isotropic behavior and uniaxial strain may be quite appropriate. .(Aadnøy, Cooper et al. 2009)

We assume that the formation is laterally constrained (no horizontal movement) and that the rock behaves elastically. Then from EQ. 23 and EQ. 24 and with $\varepsilon_x = \varepsilon_y = 0$ we can write the minimum horizontal stress in terms off:

$$\boldsymbol{\sigma'_h = \frac{\nu_{fr}}{1-\nu_{fr}}\sigma'_v} \qquad \text{EQ. 30}$$

$$\boldsymbol{\sigma_{h,min} = \frac{\nu}{1-\nu}(\sigma_v - P_f) + P_f} \qquad \text{EQ. 31}$$

Where $\sigma h, \min$ is the minimum horizontal stress, $\nu = Poisson'sratio$ and P_f is the pore pressure

Overburden pressure is thus:

$$\boldsymbol{\sigma_v = \frac{(\sigma_{h,min} - P_f)}{\frac{\nu}{1-\nu}} + P_f} \qquad \text{EQ. 32}$$

The fracture gradient according to USM can be found by:

$$\boldsymbol{FG = \sigma_{h,min} = \left(\frac{\nu}{1-\nu}\right)\left(\sigma_v - P_f\right) + P_f} \qquad \text{EQ. 33}$$

Where FG is the fracture gradient, ν is the Poisson's ratio, σ_v is the overburden pressure gradient and P_f is the fluid pressure or the pore pressure. .(Aadnøy, Cooper et al. 2009/ Fjær, E., Holt, R.M. et al. 2008)

2.4 Wellbore tubular

Expandable tubular differs from conventional liners by the alteration of the tubular mechanical properties that occur during expansion. When installing an expandable liner, the mechanical properties and dimensions the liner have on surface prior to installation is not equal the properties and dimensions after it is expanded downhole. Understanding the alterations that happens is important. This is primary achieved by understanding the mechanical properties of steel undergoing such processes, but the understanding of loads that the liner actually and possible may be exposed to is equally important for the understanding of the expandable liners behaviour.

2.4.1 Oil Country Tubular Goods

Oil Country Tubular Goods (OCTG) include the three types of seamless tubes, delivered in quenched and tempered condition.

- **Drillpipe**: heavy seamless tubes that rotate the drill bit and circulate the drilling fluid. Joints of pipe, 30ft (9m) long are coupled together with toll joints.
- **Casing pipe**: used to line the hole
- **Tubing**: a pipe through which the oil or gas is produced from the wellbore. Tubing joints are generally around 30 ft (9m) long with a thread connection at the end.

2.4.2 Failure

Tubular are classified according to their strength. In general, stronger material is more brittle and weak steel is ductile (Ugural, 2008). There are two strength criterias for steel, the yield point and the tensile strength.

2.4.3 Forces on tubular

There are huge forces acting on the tubular down hole, both from formation pressure, drilling pressure, drilling wear, bending, tensile forces etc.

When designing well tubular, the following should be taken into consideration:

- Real force
- Effective force
- Frictional force
- Failure mechanics (limits for the pipe to fail)

Loads are applied to the tubular through all the processes the tubular is meant to endure, the installation, testing, work over and production. The main loads can be categorized into the following:

- Shear loading
- Fluid loading
- Weight/Normal loading
- Hookload

If the tubular is loaded beyond its critical limits for failure, the tubular will most likely burst, collapse or rupture due to excessive external, internal or tensile forces. (Aadnøy, 2010)

2.4.4 Burst

If the difference between the external forces and the internal forces exceeds the internal yield strength of the tubular most likely the tubular will burst. This limit is called the tubulars burst strength. Burst is a tensile failure, resulting in rupture along the axis of the pipe. If the casing or liner bursts it can result in leakage and loss of well integrity of the string.

The differential pressures downhole can be very high, especially during cementing, kick and loss situations. It is thus important to identify all the load scenarios the tubular can be exposed to and calculate effect on the tubular and the safety margin towards the burst pressure. The burst pressure of a pipe is the pressure at which the pipe loses its internal pressure integrity. API calls this failure ductile rupture. The API equations for ductile rupture are for calculating the pressure at which failure of the pipe body occurs, not until the material yields.

The equations for ductile rupture depend on the following parameters:

- minimum physical wall thickness
- pipe outer diameter
- maximum depth of imperfections which have a reasonable probability of passing through the inspection process undetected,
- fracture toughness of the material,
- work hardening of the material
- ultimate tensile strength of the pipe.

The equations have been derived under two assumptions: (1) the failure of the pipe is assumed to be ductile and not brittle, even in the presence of small imperfections; and (2) bending stresses are not included, which means that the equations cannot be used for a buckled pipe or a pipe in a dogleg. The design equation for ductile rupture as defined by API is as follows (American Petroleum Institute, 2008, p. 24):

$$\boldsymbol{p_{iR}} = \frac{2k_{dr}f_{umn}(k_{wall}t - k_a a_N)}{D - (k_{wall}t - k_a a_N)} \qquad \text{EQ. 34}$$

p_{iR}= internal pressure at ductile rupture of an end-capped pipe
a_N = imperfection depth associated with a specified inspection threshold
D = pipe outside diameter
f_{umn} = minimum tensile strength
k_a = burst strength factor, usually having the numerical value 1.0 or 2.0 depending on the material
k_{dr} = correction factor based on pipe deformation and material strain hardening, having the numerical value $[\left(\frac{1}{2}\right)^{n+1} + \left(\frac{1}{\sqrt{3}}\right)^{n+1}]$ (n = the dimensionless hardening index used to obtain a curve fit of the true stress-strain curve derived from a uniaxial tensile test)
k_{wall} = factor to account for the specified manufacturing tolerance of the pipe wall
t = pipe wall thickness.

2.4.5 Collapse

A tubular collapse is due to excessive external loading. The difference between external and internal pressure exceeds the collapse strength of the material. External pressure seen by tubular is caused by the pore pressure, temperature expansion or other fluids. The internal pressure is the hydrostatic pressure from the drilling fluid column inside the tubular. Collapse is a geometrical failure, deforming the tubular to a non-circular shape. Collapse resistance is dependent on the diameter to thickness ratio, hence making thin walled tubular more exposed to collapse failure. If casing or liner collapse occurs, completion equipment may no longer pass through the casing. Studies performed by Aadnøy shows that casing wear has a considerable impact on the collapse resistance.

The API collapse design equation is used when the external fluid pressure exceeds the internal fluid pressure. The collapse equation does not account for bending. The collapse equations depend on the following parameters:

- Pipe outside diameter D
- Minimum yield strength $fymn$
- Elastic modulus E
- Pipe wall thickness t.

The calculation of the collapse pressure of a pipe is a bit more complex than the calculation of the burst pressure. There are basically three different failure modes for the collapse of pipes. These modes are elastic, plastic and yield. The formulas for elastic and yield collapse were determined analytically, the formula for plastic collapse was derived empirically. The diameter to thickness ratio and the yield stress of the material dictates in which mode the pipe fails in collapse. For high D/t ratios, i.e. thin-walled pipes, the failure mode is elastic, which means that the stress in the pipe material does not exceed the material yield stress. For lower D/t ratios the failure mode in collapse is plastic, which means that the yield stress has been exceeded and the pipe has been plastically deformed. For the API formulas for calculation of collapse pressure, there is also an empirical equation for a transition range between the elastic region and the plastic region. For pipes with a very low D/t ratio, i.e. small diameter and thick-walled pipes, the failure mode is yield collapse. The collapse pressure calculated in this region is the external pressure that generates minimum yield stress on the inside wall, and it is calculated using the Lamé equation. The applicable D/t range and collapse pressure can be calculated using formulas given by API.

Failure mode	Applicable D/t range
1. Elastic $P_E = 0.7125\dfrac{2E}{1-\nu^2}\dfrac{1}{(D/t)[(D/t)-1]^2}$	$D/t \geq \dfrac{2+B_c/A_c}{3B_c/A_c}$
2. Transition $P_T = f_{ymn}\left[\dfrac{F_c}{D/t} - G_c\right]$	$\dfrac{f_{ymn}(A_c - F_c)}{C_c + f_{ymn}(B_c - G_c)} \leq D/t \leq \dfrac{2+B_c/A_c}{3B_c/A_c}$
3. Plastic $P_P = f_{ymn}\left[\dfrac{A_c}{D/t} - B_c\right] - C_c$	$\dfrac{\sqrt{(A_c-2)^2 + 8(B_c + C_c/f_{ymn})} + (A_c - 2)}{2(B_c + C_c/f_{ymn})} \leq D/t \leq \dfrac{f_{ymn}(A_c - F_c)}{C_c + f_{ymn}(B_c - G_c)}$
4. Yield $P_{Yp} = 2f_{ymn}\dfrac{(D/t) - 1}{(D/t)^2}$	$D/t \leq \dfrac{\sqrt{(A_c-2)^2 + 8(B_c + C_c/f_{ymn})} + (A_c - 2)}{2(B_c + C_c/f_{ymn})}$
Empirical constants in SI-units:	
$A_c = 2.8762 + 0.15489 \times 10^{-3} f_{ymn} + 0.44809 \times 10^{-6} f_{ymn}{}^2 - 0.16211 \times 10^{-9} f_{ymn}{}^3$ $B_c = 0.026233 + 0.73402 \times 10^{-4} f_{ymn}$ $C_c = -3.2125 + 0.030867 f_{ymn} - 0.15204 \times 10^{-5} f_{ymn}{}^2 + 0.77810 \times 10^{-9} f_{ymn}{}^3$ $F_c = \dfrac{3.237 \times 10^5 \left(\dfrac{3B_c/A_c}{2+B_c/A_c}\right)^3}{f_{ymn}\left(\dfrac{3B_c/A_c}{2+B_c/A_c} - B_c/A_c\right)\left(1 - \dfrac{3B_c/A_c}{2+B_c/A_c}\right)^2}$ $G_c = F_c B_c / A_c$	

FIGURE 13: API EQUATIONS FOR COLLAPSE (AMERICAN PETREOLEUM INSTITUTTE)

2.4.6 Sour service

In addition to failure limits, the purpose of the tubular is equally important. If the tubular is to be installed in an environment where there is a chance of presence of corrosive gases in the borehole, we speak of sour service. These gases can lead to corrosion, leading to failure in long term or hydrogen embrittlement that may lead to short term failure. (Aadnøy, 2010)

Sour gases are gases containing H2S. Water mixed with H2S becomes sour /acidic and can create large damages on the steel tubular. As little as 50 ppm of H2S is sufficient to generate embrittlement, (Aadnøy, 2010)
Thus the choice of material must be evaluated and the required metallurgy of the tubular in each section evaluated.

2.5 Drilling Challenges

Drilling a well in high pressure environments, often with high uncertainties, introduces many challenges. Some are expected but are accounted while performing the operations. Planning a well includes taking into account and plan for these challenges. Common challenges are related to unexpected inflow of fluids, loss of fluid into the formation and problems related to unstable borehole wall.

2.5.1 Drilling hazards

Modern technology enables us to drill complex configurations with high angles, long reach trajectories and in high pressure and temperature zones. A safe drilling environment impose that the well pressure is delicately balanced between the formation pore pressure, wellbore instability curve and the formation fracture curve. It is however not possible to predict the exact pressures and the actual pressure accounted while drilling can differ to planned and different situations can occur.(Aadnøy, 2010)

2.5.2 Lost circulation

Lost circulation is defined as the loss of drilling fluid or cement from the well to a subsurface formation. Lost circulation occurs when extremely high permeability formations are encountered, and when drilled into, the wellbore pressure exceeds the fracturing pressure of the formation and the wellbore fluids enters the formation. If not cured, a lost circulation situation can result in the mud or cement amount available on the rig is used up and the well could collapse or well integrity issues could occur. (Bourgoyne Jr. & Chenevert et al.,1986)

2.5.3 Kick

A kick is the flow of formation fluid into the well. This occurs when the pore pressure exceeds the bottomhole pressure (Adam T.Bourgoyne Jr et al.). A kick is controlled by pumping heavy mud into the well, killing the well and circulate the kick volume out of the well.

2.5.4 Wellbore collapse

Wellbore collapse occurs when the pressure inside the wellbore is insufficient to support the borehole wall or the pressure difference between the external pressure and internal pressure of a tubular exceeds the tubulars collapse strength. Collapse is most severe at low mud weights. For a borehole wall, the external pressure can be considered constant when it is generated by the weight of the overburden, which does not change, the collapse is thus a function of the borehole pressure. If the borehole wall is applied stress greater than the strength of the rock, the borehole will fail. In Aadnøy, the effect of mud weight on the borehole wall in the relation of stresses, are stated. Three normal stress components are acting on the borehole wall, namely the radial stress, the tangential stress and the vertical stress plus the pore pressure. (Bourgoyne Jr. & Chenevert et al.,1986)

For tubulars the different scenarios that might lead to collapse must be identified, by calculating the pressure difference imposed by drilling, cementing, testing etc.

2.5.5 Well control

"Well control is a collective expression for all measures that can be applied to prevent uncontrolled release of wellbore effluents to the external environment or uncontrolled underground flow." (NORSOK D-10, 2004)

2.6 Well integrity

According to NORSOK Standard D-010, Rev.3 August 2004 "Well integrity in drilling and well operations" the following is stated for casing design:

"*All components of the casing string, including connections, circulation devices and landing string shall be subjected to load case verification.The weakest points in the string with regard to burst, collapse and tensile strength rating shall be clearly identified."*

In section 2.9, load cases that shall be considered as a minimum is listed. The list is not comprehensive and load cases applicable for the planning activity shall be applied.

2.6.1 Well barrier

According to NORSOK D-010, 2004 a well barrier is *"an envelope of one or several dependent barriers elements preventing fluids or gases from the flowing unintentionally from the formation, into another formation or to surface"*

2.6.2 Well barrier element

"Object that alone cannot prevent flow from one side to the other side of itself". (NORSOK D-10, 2004).

2.7 Monobore

A conventional well has a telescopic well profile where the ID is reduced for every string installed, where as a monobore maintains the ID through the next casing string. An ideal monobore well have a constant ID from top to bottom.

2.8 Underreaming

When drilling the a section in the well, the drilling bit used must pass through the previous casing and as long as it is not an expandable bit, the hole size is limited to the ID of the previous casing string. In some cases a larger hole is required and an underreamer can be used to open the hole additionally. (Aadnøy & Cooper et al., 2009)

2.9 Load on wellbore tubular

A load case is the description of internal pressure, external pressure and temperature over the length of a casing string at a point in time (Aadnøy & Looyeh, 2009). The load case describes an event that can occur in the life of the well, such as a kick or a frac job down the production casing. The analysis is divided into three operational phases for each string.

The loads are quantified in three main categories, burst, collapse and axial loads during installation, burst loads after installation and collapse loads after installation.

Once a design approach is selected, the possible load scenarios and the load parameters must be established, the principal loads at every point in the string must be calculated, being axial force, internal- and external pressure, bending stress and torsion. The strength required to resist the loads is then found. The uncertainties in load calculations are the actual loads the casing will endure, when the loads described are future events, the casing strength (this specially apply to expandable tubular) and the failure modes and consequences. Some of this uncertainty is met with including safety factors in the design. The basic loads that need to be calculated are presented in sections below.

2.9.1 During installation (initial conditions)

This phase defines the fluids, pressures and loads that a liner might be exposed to during the installation of the string i.e. load cases from running the casing until the casing is cemented and a green cement pressure test performed. (Aadnøy & Cooper et a.l 2009)

2.9.2 Burst load after installation – drilling and production

This phase defines all the burst loads the casing might be exposed to during the well life after the cement has set.

The burst load at any depth is defined as follows:

$$\boldsymbol{P_{burst} = P_i - P_o} \qquad \text{EQ. 35}$$

Were P_i is the internal pressure and P_o is the external pressure (outside pressure) of a casing string. The casing will burst if the pressure difference between the internal and external pressure exceeds the casing burst strength.

The burst internal loading is the surface pressure plus the hydrostatic pressure of the fluid in the casing. The load can be a planned pressure load, like the pressure test or an unplanned but possible load such as a kick or tubing leak. Any scenario when unwanted high pressure might build up inside the casing can lead to burst. The counteracting pressure on the outside of the casing depends on the fluid. This pressure profile depends on the situation and can be mud hydrostatic, mud base fluid, pore pressure, base fluid density of cement or a combination of fluids (Aadnøy & Cooper et a.l 2009). It is reasonable to use pore pressure backup in the open hole below the previous casing shoe.

The main burst loads are presented in sections below.

2.9.2.1 Drilling kick

Drilling kick is normally the critical drilling burst load. The worst case is when the internal pressure is the maximum expected well head pressure (MEWHP) during a kick plus a gas gradient to the shoe.

$$P_i = MEWHP + \rho_i * TVD * 0,0981 \qquad \text{EQ. 36}$$

Were P_i is the internal pressure and $MEWHP$ is the maximum expected wellhead pressure. The counteracting external pressure will be the mud gradient to top of cement (TOC) assuming a short time frame. The cement mix water gradient for cemented pipe in pipe assumes that the cement is set and the density has reverted to mix water. (Aadnøy & Cooper et a.l 2009). The external pressure profile is then:

$$P_o = \rho_{MW} * TVD * 0,0981 \qquad \text{EQ. 37}$$

Where P_o is the external pressure and ρ_{MW} the density of the mud weight.

For mud weight gradient above TOC:

$$P_o = P_{TOC} + (TVD - Depth_{TOC}) * \rho_{water} * 0,0981 \qquad \text{EQ. 38}$$

For cemented pipe in pipe, the pressure below previous casing shoe is:

$$p_f = Pore\ pressure \qquad \text{EQ. 39}$$

2.9.2.2 Pressure test

The pressure test internal load is the test pressure plus the mud gradient to the shoe. The normal assumption is that the internal mud weight is the mud weight in the hole when the casing was run and set. If the plug was displaced with a displacement fluid, this should be used.

The internal pressure for this case is then:

$$P_i = P_{surf} + \rho_i * TVD * 0,0981 \qquad \text{EQ. 40}$$

External pressure is the same as for drilling kick. (Aadnøy & Cooper et a.l 2009)

2.9.2.3 Production tubing leak

The tubing leak internal load is the shut-in tubing pressure (SITP) plus a packer fluid gradient to the packer depth. This assumes leakage at top which is worst case when it will give the largest hydrostatic column in the annulus. Production tubing leak is normally the critical production burst load for wells that are not stimulated. (Aadnøy & Cooper et a.l 2009)The internal pressure is then:

$$P_i = SITP + \rho_i * TVD * 0,0981 \qquad \text{EQ. 41}$$

The time frame can be long, therefore it is often assumed that the mud outside is degraded.

2.9.3 Collapse load after installation – drilling and production

This phase defines all the collapse loads the casing might be exposed to during the well life after the cement has set.

Collapse load at any depth is defines as:

$$P_{collpase} = P_o - P_i \qquad \text{EQ. 42}$$

The casing collapses if the pressure difference between the external and internal pressure exceeds the casing collapse strength. The external pressure is the hydrostatic pressure like cement, mud and/or pressure. The internal pressure depends on the fluid, or lack of fluid on the inside. (Aadnøy & Cooper et a.l 2009)

2.9.3.1 Cementing

This load can become an issue for large OD casing set deep with a light displacement fluid. (Aadnøy & Cooper et a.l 2009). The internal pressure in this case will be:

$$P_i = \rho_{displacement\ fluid} * TVD * 0,0981 \qquad \text{EQ. 43}$$

The external load is the unset cement and the hydrostatic pressure on the outside of the casing.

$$P_o = \rho_{MW} * TVD * 0,0981 + (Z - Z_{TOC}) * \rho_{Cmt} * 0,0981 \qquad \text{EQ. 44}$$

2.9.3.2 Drilling

The drilling collapse assumes lost return, resulting in fluid level drop to some depth. The depth may be determined arbitrary or calculated by balancing the depleted pressure with MW. Internal pressure above the fluid is zero. The internal pressure below the fluid is MW. (Aadnøy & Cooper et a.l 2009)

$$P_i = 0 \quad \textit{(above fluid level)} \qquad \text{EQ. 45}$$

$$P_i = \rho_{MWi} * (Z - Z_{FL}) * 0,0981 \quad \textit{(below the fluid level)} \qquad \text{EQ. 46}$$

2.9.3.3 Production casing evacuation

Here, zero internal pressure is worst case.

$$P_i = 0 \quad \textit{(for full evacuation or above the fluid level)} \qquad \text{EQ. 47}$$

External pressure is the same as for drilling collapse. (Aadnøy & Cooper et a.l 2009)

2.9.4 Tension loads

Typical tension loads include overpull while running casing and bump plug while cementing. (Aadnøy & Cooper et a.l 2009)

3 Expandable technology

3.1 Introduction

Expandable liners are steel tubular that are expanded downhole to increase the inner diameter of the tubular. A specially designed steel tubular is run downhole, usually on drillipe, and expanded to a larger diameter by using an expansion cone or expansion mandrel that is pushed or pulled hydraulically or mechanically up-down or down-up to expand the pipe.
This is achieved by pushing or pulling a hydraulically or mechanically operated mandrel through the tubular after it is installed downhole and expanding it by cold working the steel. The tubular is expanded beyond its yield limit, and the tubular is hence permanently deformed.

The development of expandable tubular technologies was initiated by the business need to reduce drilling costs, when a large amount of the drilling cost is related to the cost of tubular, to increase production of tubing constrained wells and to enable operators to access reservoirs that could otherwise not be reached economically without using expandable wellbore tubular. (Metcalfe, 2002)

The tubular must be of perfect cylindrical shape to enable expansion without failure. There are both open-hole and cased hole tubulars available. The cased hole expandable is used as a casing patch to close off perforations, cure tubing leak or casing wear without adding much to the ID of the well. The openhole solutions application is to close off troubled zones, add casing string used for solving lost circulation problems and sealing off trouble zones like when the pore pressure/fracture gradient relationship is of concern.(Cammata 2012)

The system is run through the previous casing and then expanded downhole. Some is cladded inside the previous casing and some are cladded into a recess shoe, the first decreasing the ID slightly while the later maintains the ID in a monobore fashion. As the liner is expanded, its outer diameter (OD) increases significantly, while the wall thickness decreases only slightly. This preserves the greatest post-expansion burst and collapse values possible.(Cammata 2012)

An expansion cone or mandrel is used to permanently deform the pipe. The cone is propagated through the tubular by a different hydraulically pressure across the cone itself and/or by directly pull or push force. The differential pressure is applied by pumping through a workstring connected to the cone, and the mechanical force is applied by either raising or lowering the workstring. The progress of the cone through the tubular deforms the steel past its elastic yield limit into its plastic deformation region, but not its ultimate yield strength. At the bottom of the system is a canister containing the expansion mandrel. This canister is commonly known as the launcher. The launcher is constructed of thin walled high strength steel that has a smaller wall thickness than the expandable casing. Because the launcher has a thinner wall and its outside diameter (OD) is the same as the drift of the previous casing, it can be tripped into the hole through the previous casing string. The difference in wall thickness between the launcher and the elastomer-coated hanger joint(s) allows the expanding pipe to be sealed, or “clad” to the previous casing string. The expanded pipe ends up with an outer diameter after expansion that is greater than the outer diameter of the launcher, while the inner diameter of the pipe expands to the same inner diameter of the launcher”. (Daigle & Cambo et al. 2000)

3.2 Application

Casings and liners can be expanded against the previous casing/liner in such a way that each time they are set, the well diameter is just reduced by two tubular wall thicknesses. The open hole solution was a way to provide the operators a cost saving and effective way to have an extra casing string in planned and contingency operations. You could increase your conventional casing length without an ID reduction.

The cased hole enables operators to repair existing damage or worn casing and it could be used for shutting off producing zones by shutting off perforations. The setting procedure is similar to the open hole, but only a shirt peace of pipe is used in the area of interest. The casing in place is then reinforced by the extra casing layer.

3.3 Material selection

Materials for the component of the expansion assembly are chosen for sufficient strength, ductility, impact toughness, wear and environmental cracking (Cammata 2012). Expansion decreases the collapse rating of tubulars, probably as a result of Bauschinger effect; occurs when plastic flow in the expanding direction lowers the applied stress at which plastic flow begins in the reverse direction (collapse), but the expansion process appears to have no detrimental effects on the burst strength. A test on L80 pipe indicate that, if the pre- and post-expansion dimensions are the same, collapse resistance could decrease to about 30% as a direct result of the expansion. (Filippov & Mack et al., 2009)
Special cement is required when the slurries' properties must allow for longer thickening time when the cement need to be in fluid phase during expansion, and the cement must create effective zonal isolation in a smaller annulus than normal. (Filippov & Mack et al., 2009)

3.4 Expansion method

Solid tubing expansion can be accomplished by using a cone of ceramic, tungsten carbide or hardened steel that is either mechanically pulled or hydraulically pushed.(Enzie & burge et al. 2000)

3.5 Post expansion properties

Knowledge of post expansion mechanical properties like post expansion strength, ductility, impact toughness, collapse, burst is crucial (Filippov & Mack et al., 2009). Understanding the post expansion properties of the expanded tubular is the greatest challenge faced by the industry today. This has been part of the reluctance to apply expandables as part of the planned casing design. Especially if the expandable must endure life load conditions.

Up until recently, most of the research done on expandable tubulars is based on finding a fit for purpose solution for specific field problems. To fully understand and to be able to standardize expandable technology, the understanding of possible failure mechanism during its lifetime is important. A significant aspect is the understanding of the pre and post mechanical and material characterization. The numerical models used until today are simple models for calculating/estimating operational parameters like expansion force, length shortening and wall thinning. Complete and accurate measurements of the post expansion properties is necessary to correctly evaluate the tubular life and performance envelope. In particular, the collapse resistance is very critical because expanding the tubular degrades its value. (Pervez & Khan et a., 2011l).

Perez & Khan et al., (2011) performed a study based on comparison of experimental and simulation results for the expansion process of expandables and concluded that the wall thickness of expandable tubular decreases linearly as the expansion ratio increases. Tubular length shortens under fixed-free end conditions and varies linearly with expansion ratio. Moderate to large reduction occur in burst pressure and collapse strength of tubular with an increase in expansion ratio. God agreement was found between collapse result using API equation and the prediction by finite element. The result shows clearly that large expansion ratio is restricted by the reduction in collapse strength. Further, microstructure was studied and there was found a small change in grain size after expansion. The formation of shear band shows the effect of excessive plastic deformation on the microstructure level. Extensive research is needed to determine the changes in mechanical properties origination from the changes in microstructure of expandable tubulars.

3.6 Cementing expandable liners

The expandable liner can be, just as easily, cemented as a conventional liner. Dependent on vendor the expandable liner is cemented before or after expansion. Cementing after expansion allow the use of conventional cement while cementing prior to expansion requires a cement slurry with a slower settling time to ensure the cement is not set before the expansion is completed. (Cammata, 2011)

3.7 Connections

The weakness of most expandable tubulars is the connections. As per today all expandables have threaded connections which are not tight. (Sunde, 2012)

3.8 Advantages

- Can be used as a “drilling liner” for depleted reservoirs and lost circulation zones
- Can be used to extend a strings casing shoe if the casing need to be set shallower than planned
- Close off perforations
- Repair casing
- Shut off unwanted fluid entry

3.9 Challenges

Due to the low D/t ratio after expansion, the expandable have lower burs and collapse ratings than standard pipes used in the industry. The limiting factor of expandables is the low collapse strength. In deep water with high pressures the expandables does usually not have the required strength withstand the large forces. Knowledge of collapse strength of the expandable is necessary. The collapse safety factor is sensitive to mud weight (Kumar & Marker et al., 2010), so knowledge about wellbore pressure and drilling mud is a must. Due to the connections not being gas tight, the expandable liner must be covered with a production liner when used as a drilling liner.

4 Skarv casing design

4.1 Introduction

A casing or liner is run for one or several reasons; to provide structural support for the wellhead/other structures, maintain wellbore stability, isolate formations, or to control well pressure during drilling, production and intervention. To optimize the casing scheme in a well, thorough casing design is required.

"The casings in a well are load bearing structures. The goal of casing design is to ensure with sufficient confidence that the casing strength exceeds all loading during the entire service life of the tubular". (Aadnøy & Looyeh et a.l 2009)

Thereby, the aim of casing design is to ensure:

load < resistance

for all possible scenarios.

The casing scheme is restricted to what is wanted at the bottom, and a conventional casing design starts with the required size at bottom and establishes the size sequence upwards. The depth of the casing shoe for each string is established based on pore pressure, fracture gradient and wellbore stability analysis. The loads on the strings must then be estimated and a standard tubular that matches the loads are selected by the size, grade, weight and connections of the casings that can endure all the loads.

The design constraints are usually the minimum acceptable design factor for a given load, diameter restrictions to pass through the previous casing, desired bottom hole size and minimum casing ID to pass through completion equipment and running clearance for the next string.

4.2 Skarv development casing basis of design

A Casing Basis of Design (BP, 2011) has been prepared to document the casing design assumptions and analysis for the Skarv Development. All casing design on Skarv is based on this document. The design evolved from evaluating offset wells and surrounding fields and is the document to be used as a basis for all well design in the Skarv area. The casing design is conducted in accordance with BP Tubular Design Manual BPA-D-003, and is such that the casing will be capable of withstanding all imposed drilling and completion loads.

4.2.1 Introduction

The casing strings used in the Skarv Area are a typical combination of that seen elsewhere in the North Sea, namely

- 30" conductor
- 20" surface casing
- 13⅜" intermediate casing
- 9⅝" production casing or liner

Wells planned for Skarv segment A,B,C,E will target the deeper laying Garn, Ile and/or Tilje. In addition a 10 3/4" section will be required to accommodate the 7" TRSCSSV part of the large 7" bore completion schemes. For a smaller sized 5 ½” completion schemes it will be sufficient with 9 5/8” or 9 7/8” to surface. A 9 7/8” section at the bottom was chosen instead of 9 5/8” to increase collapse- and wear resistance during drilling operations.(BP, 2011)

4.2.2 Base case design and contingency

Figure 14 shows a schematic of the base case and contingency solutions identified for Skarv.

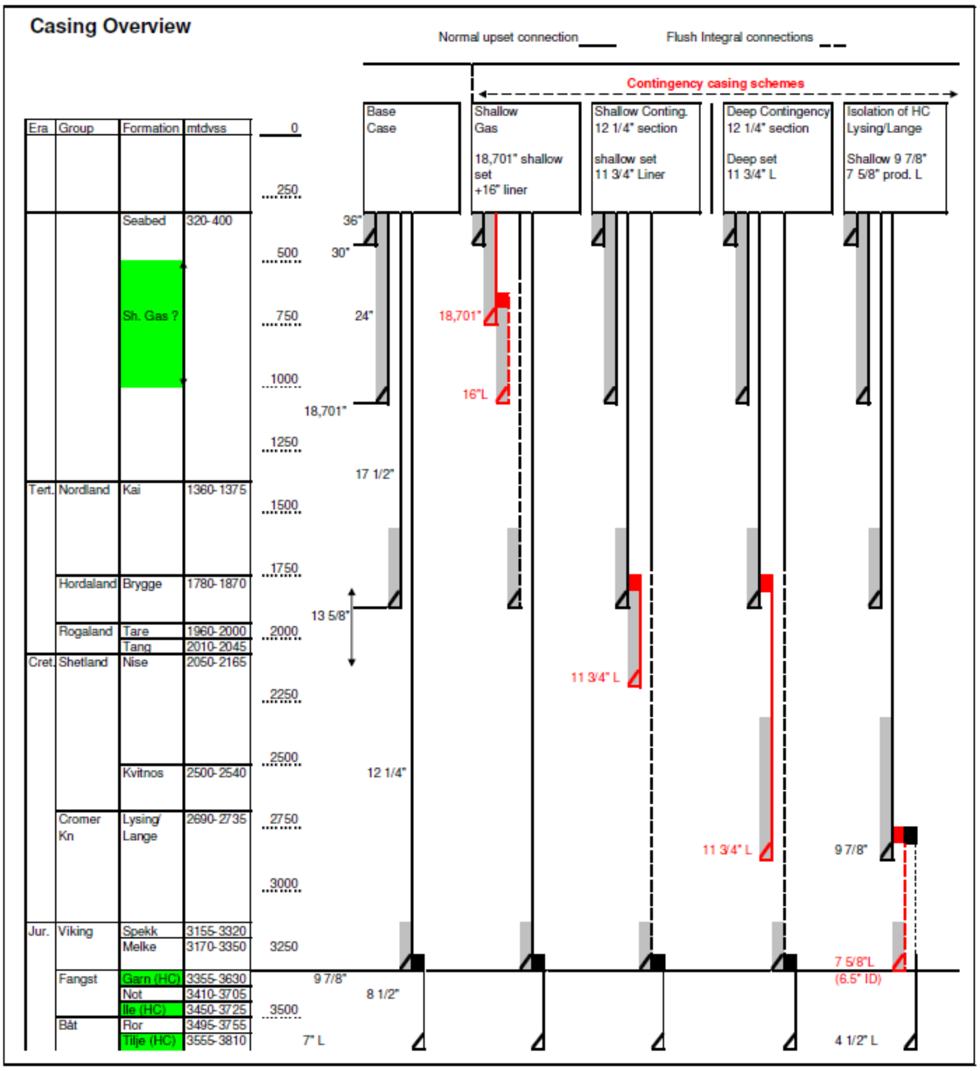


FIGURE 14: CASING SCHEME FOR SKARV/IDUN DEVELOPMENT. (BP, 2011)

4.2.3 Casing design objectives and key risks

The key design objectives for the Skarv casing design are identified as the following (BP, 2011):

- All drilling and completion load cases are met
- Sufficient allowance has been made for casing wear
- The same technical rigor is applied to the selection of suitable connectors
- Metallurgy selection is confirmed
- Casing point justification is clearly documented
- Sufficient kick tolerance is available for each hole section

The following sections are extracted directly from the document Casing Basis of Design (BP, 2011) for the Skarv field. The sections are reproduced to ensure that the proposed designs in this thesis are in compliance with the already in place casing design. Only the sections found to be relevant to the scope of work in this thesis, namely investigating possible casing design solution by the use of expandable liner for a reduction of diameter loss through the reservoir, are presented.

4.2.4 Design assumptions

Skarv casing design is based on well OPC4, B-5.(BP, 2011) This was based on the well profile in terms of expected inclinations, doglegs, azimuth, and vicinity to the highest observed pore pressure. The design is further based on the following assumptions:

- An uncertainty factor of 0.05 sg is added to the fracture gradient to account for the range in fracture gradients
- Highest EMW for pore pressure, well control and well bore stability were utilized to define mud weight requirement for the different hole sections
- All temperatures are set to default in StressCheck. For kick calculations a temperature gradient of 4.5/100m is used in the overburden while a gradient of 2.5degC is used in the reservoir
- The fluid gradient was assumed to be Garn gas 0.184sg (0.08psi/ft) for oil and gas producing wells
- For gas injectors the injected gas was also assumed to be Garn gas 0.184sg
- Wellhead pressures were either calculated based on expected reservoir pressures or based on flowline design pressures
- Test pressures were based on maximum anticipated WH pressure for the lifetime of the well, including 10% safety margin
- The stress analysis done has been utilizing the default material properties as available in Stress Check for steel

4.2.4.1 Well Objectives (BP, 2011)

- Design life to be fixed at 25 years.
- Preferably develop upper completion designs along a monobore philosophy
- All well types will require some intervention depending on the completion components selected and production related failure mechanism and maintenance methods applied
- Well design needs to be flexible for changes in well status (e.g. well status may change through the life of the well)
- Minimum hole size through the reservoir to be no less than 8 ½”

4.2.5 Pore/fracture pressure modeling

The pore pressure prognosis used for the casing design is based on the generic 5-1 well (BP, 2011):

- Over-pressure is initiated close to the top of the Kai Fm and increases until Nise Fm. This over-pressure is associated with smectitic and illitic clays in the lower Tertiary.
- Over-pressure gradually reduces down through the Nise Fm and then more dramatically through the Kvitnos Fm to the Top Lysing Fm, associated with breakdown of smectite and the initiation of quartz cementation.

- Over-pressure begins to ramp-up again through the underlying Lange Fm to a maximum in top Melke Fm. This interval contains numerous porous and permeable sandstones, possibly associated with proximity of the mature Spekk.

4.2.6 Kick tolerance

Kick tolerance is defined as the maximum volume of kick influx that can be circulated out of the well without breaking down the formation at the open hole weak point. (Aadnøy, 2010)

Well Control Tool Kit 2002 has been used to calculate the kick tolerance for drilling the 12 1/4"- and 8 1/2" hole section. The BP well control group practice, GP 10-10, states that for all wells the design kick tolerance shall be greater than 25 bbl based on maximum anticipated pore pressure and planned mud weights. (BP, 2011)

4.2.7 Detailed casing design

StressCheck Version 2003.16 has been used for the casing design analysis. The design is based on the generic C-4 well (B5) which has the longest trajectory of the planned Skarv wells in addition to high inclination in the overburden.(BP, 2011)

TABLE 4.1: CASING SPECIFICATION AND SETTING DEPTHS FOR BASE CASE DESIGN (BP, 2011)

Casing Size	Setting Depth m TVD	Setting Depth m MD	TOC m MD	Wt (ppf)	Grade	Collapse* (bar)	Burst* (bar)	Coupling
10 ¾" x 9 7/8"	580 3432	580 4612	3146/4070**	65.7 62,8	SM125S SM125S	539 758	824 941	Vam Top Regular Vam Top Regular

* Collapse and burst ratings are pipe ratings
** Cement height for 10 3/4" x 9 7/8" casing is TOC 650m above shoe or 300m above shallowest HC zone (Lysing/Lange Fm.).

4.3 Completion

The sand face completion will be either 6 5/8" or 7" standalone screens or 7" perforated liner, based on sand control measures. (BP, 2012)

5 Vendors of Expandable liner

There are three primary suppliers of solid expandable tubular, Weatherford, Enventure Global technologies and Baker Hughes. In the following section, the expandable technologies available from each of the vendors will be presented separately and then compared in section 5.4.

5.1 Enventure Global Technology – *SET®* technology

ENVENTURE Enventure GT (Global Technologies) is in many ways considered the marked leader in expandable technology. Enventure GT is a spin-off of the Shell-Halliburton collaboration and has the longest track record for expandables. The company was founded in 1998 and their first expandable was installed in 1999. Enventure has since then installed 1300 expandables worldwide, where most onshore and 34 of them in Europe (Cammata, 2012).

Enventure GT offers:

- Solid Expandable Tubular (SET®) Openhole liner systems
- SET® Cased hole liner system
- SET® Casing patches

The openhole liner system is the option considered for Skarv in this thesis.

5.1.1 Enventure GT SET® solid expandable system

The most common use of solid expandable tubular has been the openhole liner system. These are not limited to straight holes, but have also been developed for side-tracking operations and horizontal wells. (Cammata, 2012)

The first applications of SET® Openhole Systems were mostly to mitigate trouble zones such as borehole instabilities and pore-pressure/frac gradient issues in an open wellbore. Today, however, the technology is used in multiple scenarios as part of well architecture. One common use is to strategically place the SET® System in the well design in order to slim down the entire wellbore. This can increase the rate of penetration (ROP), maximize recovery, and increase efficiency while reducing overall environmental impact. Other applications include extending reach, preemptively mitigating risk in exploratory drilling, and maximizing recovery in sidetracking operations. Expandable tubular can be used in the open hole either as a temporary drilling liner or as a permanent liner tied back to the previous casing string. Temporary drilling liners can be used in applications where a contingency liner is required. (Cammata, 2012)

According to Enventure, utilization of the open hole system can:

- reduce the telescoping effect of the conventional drilling process
- improve production potential
- allow zonal evaluation with conventional logs
- offer affordable casing of trouble formation while retaining maximum internal diameter

The system is comprised of four primary sections:

- The cone launcher and float shoe
- The liner typically made from modified 80 ksi minimum yield strength pipe
- The hanger section with elastomeric seals

- The inner string (drill pipe) which is attached to the expansion cone

The housing at the bottom of the SET® system, known as the launcher, contains an expansion assembly as well as a float assembly and is typically constructed of thin-wall, high-strength steel. As in contrary to the two other vendors, Enventure system is a bottom up expansion system. (Cammata, 2012)

The reason is:

- Does not require rat hole to accommodate the liner during expansion. During the expansion process, the enlargement of the pipe diameter causes the overall pipe length to shorten from the top as a result of material balance
- Workstring operations: it is easier to generate greater forces by pumping through and pulling on the workstring than it is by adding weight to the workstring.

5.1.1.1 Features

- The expandable liner has a elastomer seal at top which fill the annular space between liner and casing and seals to the previous casing and serves as the liner hanger and liner top seal, replacing top packer and liner hanger.
- The custom-designed expansion assembly contains a solid cone that is driven through the expandable tubular using hydraulic pressure or mechanical force, or a combination of both, which enlarges the pipe radially.
- The system is run through the previous casing or liner and is positioned in open hole. The expandable OHL is then expanded bottom up. When the expansion cone reaches the overlap between the expandable OHL and the existing pipe string, the cone expands a special hanger joint to provide a permanent seal between the two strings.
- The SET is run in hole and set on slips on surface with one or several elastomer joints made up on top of the liner. This will serve as the hanger and top seal. At the bottom a pig/mandrel system (pig launcher) is attached. The assembly are tripped down with centralizers to avoid buckling, after in place in the hole, a special cement slurry with long setting time to enable expansion is pumped on the outside of the liner. A latching dart follows the cement enabling pressure to build up high enough for the pig to have enough power to expand the pipe.

5.1.1.2 Technical specifications (Enventure, 2012)

Maximum Temperature Rating: 400ºF (204ºC)

Drill out Time: Drill out time can range from less than an hour to six hours based on the type of bit utilized, rotation speeds, and weight on bit. The material to be drilled out is made of aluminum and composite material (see illustration below).

Pressure Ratings: Collapse and burst pressures are size dependent. Information on each system size is on the SET® Chart.

Cementing: Cement volumes are calculated on whole volume with longer setting times to accommodate the expansion process. The amount of lead and tail cement is calculated then pumped so that the top of the cement is at ~50 percent of the liner length before expansion. As expansion occurs the cement fills the remaining annulus.

Liner Length: Liner length is weight dependent and is calculated at the time of design. The longest Openhole System installed to date was a 7-5/8 x 9-5/8” system of 6,935 ft (2,114 m).

5.1.1.3 Running procedure Enventure SET® technology (Cammata, 2012)

1. To facilitate the expansion process, the wellbore section is drilled and often under reamed to ensure the proper hole size. In cased-hole applications the existing casing is cleaned to ensure successful expansion.
2. After the openhole section has been drilled and the drilling fluid properly conditioned, the hole should be drifted with a dummy launcher or full gauge bottomhole assembly. Caliper logs may also be run to ensure adequate hole diameter.
3. Once the drill string has been pulled, the launcher assembly is picked up and the liner made up and run. Connection makeup with torque turn monitoring is normally used.
4. Run in hole with the expandable liner, expansion assembly and launcher. The largest OD of the system is the launcher. If this passes through, the expansion will be possible.
5. Following the running of the liner, it is set in the slips and the inner string is run using a false rotary table.
6. The inner string is then made up to the expansion cone in the launcher assembly via a safety sub.
7. The liner is then run to bottom on the drill pipe.
8. If cementing is planned, the cement is then pumped, a dart dropped and the cement displaced. Cement volume should be calculated to allow the post-expanded cement top to be short of the hanger assembly usually 7o% of the post –expansion annulus. It is important to keep away from the elastomers to mitigate debris being couth between the elastomers and base casing wall and limiting sealing capability.
9. Once the dart has seated, pressure is applied to rupture pressure disks and releases the cone.
10. Expansion is initiated and continues with hydraulic pressure via the inner string and mechanical force by pulling the inner string. Liner expansion is normally 20 – 30’/min.
11. The inner string is pulled out of the hole as expansion continues until the upper hanger/sealing joint is expanded to the base casing and the cone exits the top of the liner. The expansion is hydraulic until the pull out when it becomes mechanically to avoid champagne effect.
12. Expand hanger joint.
13. Drill out the expandable liner float shoe. The shoe is about one meter in lenght. Enventure have the following BHA recommendations: drill out, if the bit is smaller than the drift ID, mill (watermelon) behind.
14. The hole can then be circulated and pressure tested. Barring any problems, the liner is now ready.

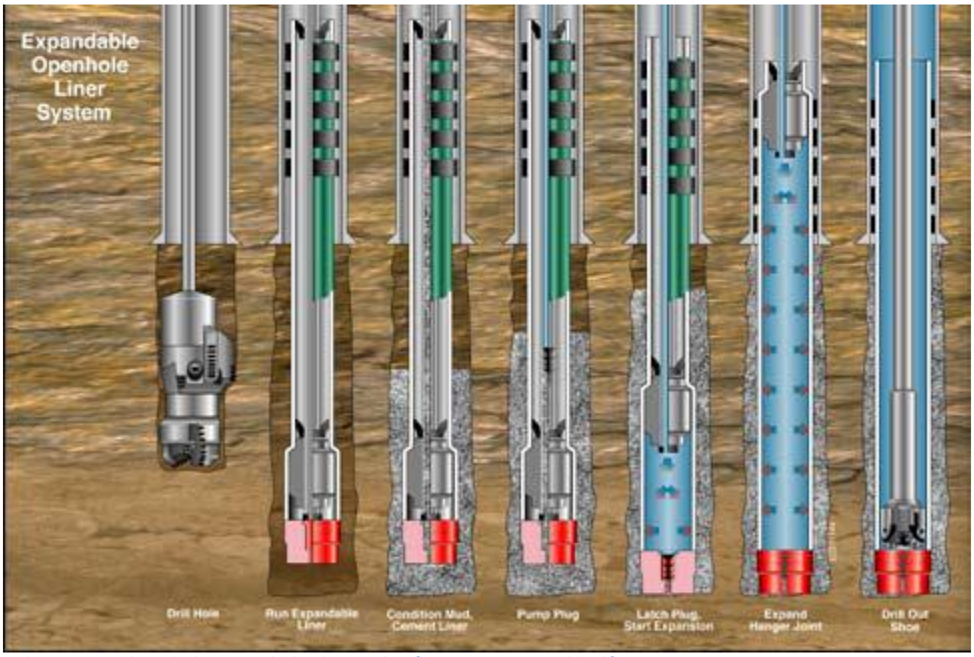


FIGURE 15: SET® SETTING SEQUENCE (ENVENTURE, 2012)

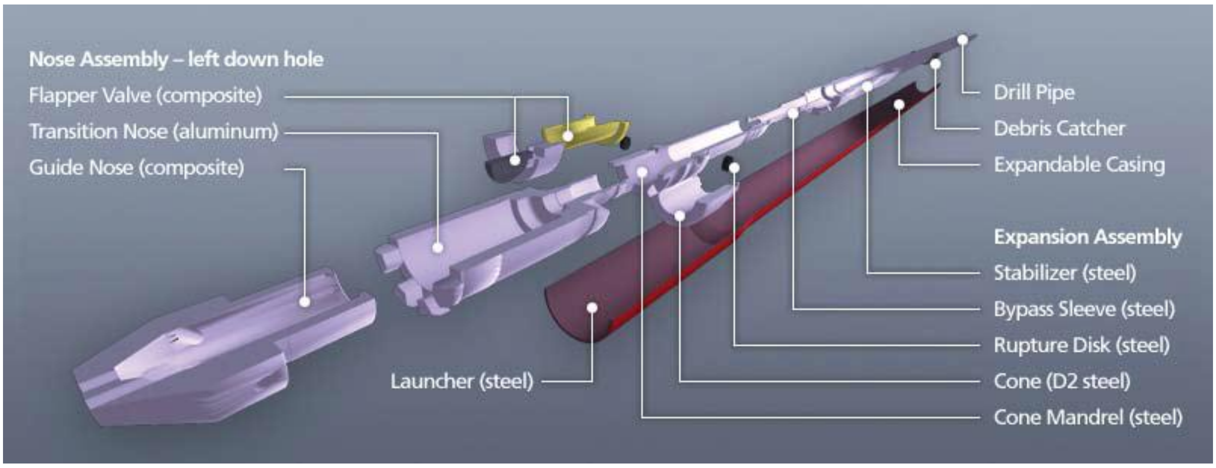


FIGURE 16: SET ASSEMBLY BY ENVENTURE (ENVENTURE, 2012)

5.1.1.4 Advantages

- Inside coating to avoid friction (lubrication)
- The liner is tested while expanded, so no pressure-test required, but some like to pressure-test top of liner to be sure

5.1.1.5 Challenges

- The connections are not gas tight
- It has been found difficult to cement small sections, however, Enventure is in the process of curing the problem by the use of a foam ball and elastomers to seal instead
- Current: composite nose which is difficult to drill. This is the area that is under development at the time
- WellPlan is used to calculated string properties, it is not straight forward to analyze expandable tubular in StressCheck but Enventure are in dialog with the supplier of

StressCheck to incorporate expandable tubulars into the software and enable operators to do in-house calculations

- The bottom-up expansion does not make room for retrieving the liner if problems occur
- Results in shrinkage on top of the tubular during expansion. Because of this a sufficient rat hole is required to accommodate excessive length
- It is recommended to not cement more than 70% of the post annular volume to mitigate debris between the elastomer seals and base casing wall. If fully cemented is required, this can be solved by installing debris catchers just below the elastomer section

5.2 Baker Hughes – *linEXX* ™ system – monobore

"Baker Hughes provides expanded solid tubulars that enable operators to maximize hole size while minimizing NPT in openhole" (Baker Hughes, 2012). They came on the expandable market in 1994 with the *ZXP*™ liner packer system. They were the first vendor to perform a one-trip expandable completion system that included an expandable hanger, expandable solid pipe, expandable screens and expandable zonal isolation devices. That technology led to the first deployment of a monobore expandable liner extension system and casing exit from a monobore expanded liner extension in a subsequent application. They were the first in the industry with a close-tolerance expandable centralizer for ensuring good cementation. (Baker Huhes, 2012)

Baker Huhges offers

- Baker Hughes *linEXX*™ monobore expandable liner extension
- Nested liners
- Clads dor Tubing/Liners /Casing
- Openhole clads
- Monobore Openhole clads

5.2.1 Baker Huhges *linEXX*™ monobore expandable liner extension

The *linEXX*™ monobore expandable liner extension is a system which enables maintaining the same pass-through ID as the previous casing/liner by running a recess shoe on the base of the previous casing and cladding the expandable into the recess shoe by a metal-to-metal seal without decreasing the pass-through ID. The recess shoe has equal or smaller OD than the base casing connections and does not require additional drift ID to pass through. The system is designed to block off troublesome drilling sections to minimize Non Prodictive Time (NPT) or to be included in the initial well design to maximize hole size to the reservoir. (Baker Huhes, 2011)

The approach is accomplished typically by running a recessed shoe on the conventional 9 5/8" casing. The shoe and the next hole section are then drilled out conventionally to the next casing point or until a drilling problem is encountered. The *linEXX*™ system is deployed and expanded on a single trip to extend the previous casing string without a change in drill bit size or the following openhole size. (Sunde, 2012)

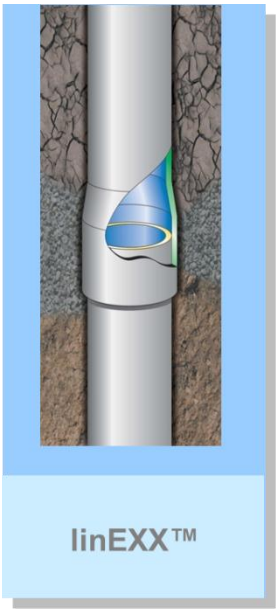


FIGURE 17: LINEXX (BAKER HUGES, 2011)

Unlike other expandable liner systems the Baker Hughes system lets operators use conventional bit and tubular sizes to further control drilling costs. (Baker Hughes, 2011)

The system is a top-down expansion technology that enables backup tool redundancy and conventional cementing processes post-expansion. Additionally, if there are unplanned events during the expansion process, such as unpredicted weather conditions or equipment related problems, the system enables you to abandon work without a loss, and come back later and finish the expansion. (Sunde, 2012)
The top-down expansion however shrinks the expandable at bottom and additional rathole is needed to account for the excess length required pre-expansion to ensure the correct length after expansion. (Baker Huhes, 2011)

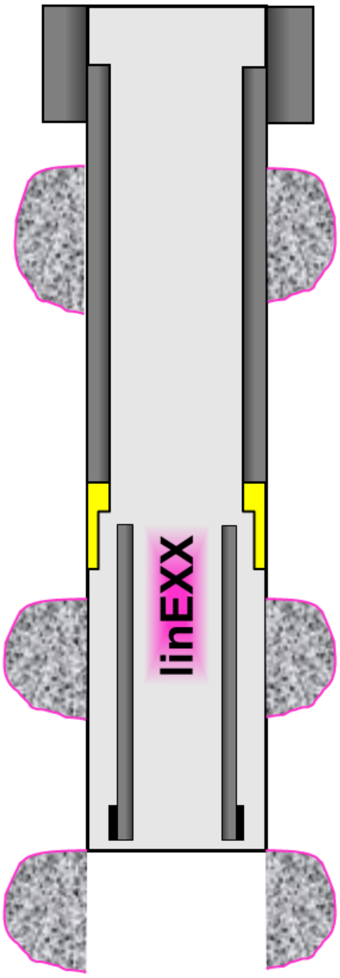


FIGURE 19: LINEXX™ CONCEPT (BAKER HUGES, 2011)

FIGURE 18: TWO STAGE EXPANSION CONE (BAKER HUGHES, 2011)

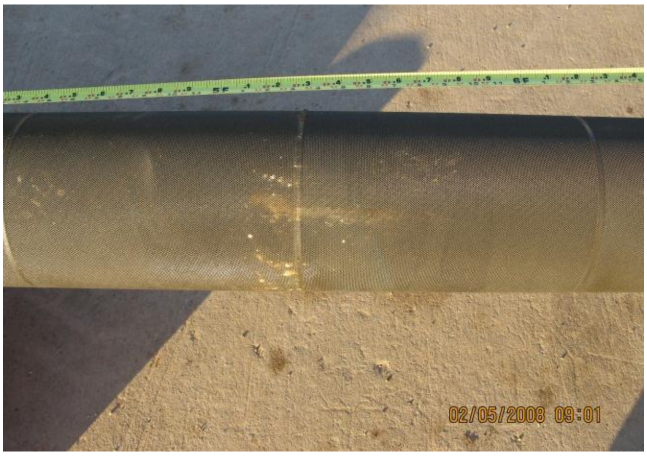


FIGURE 20: LINEXX™ HANGER/PACKER (BAKER HUGES, 2011)

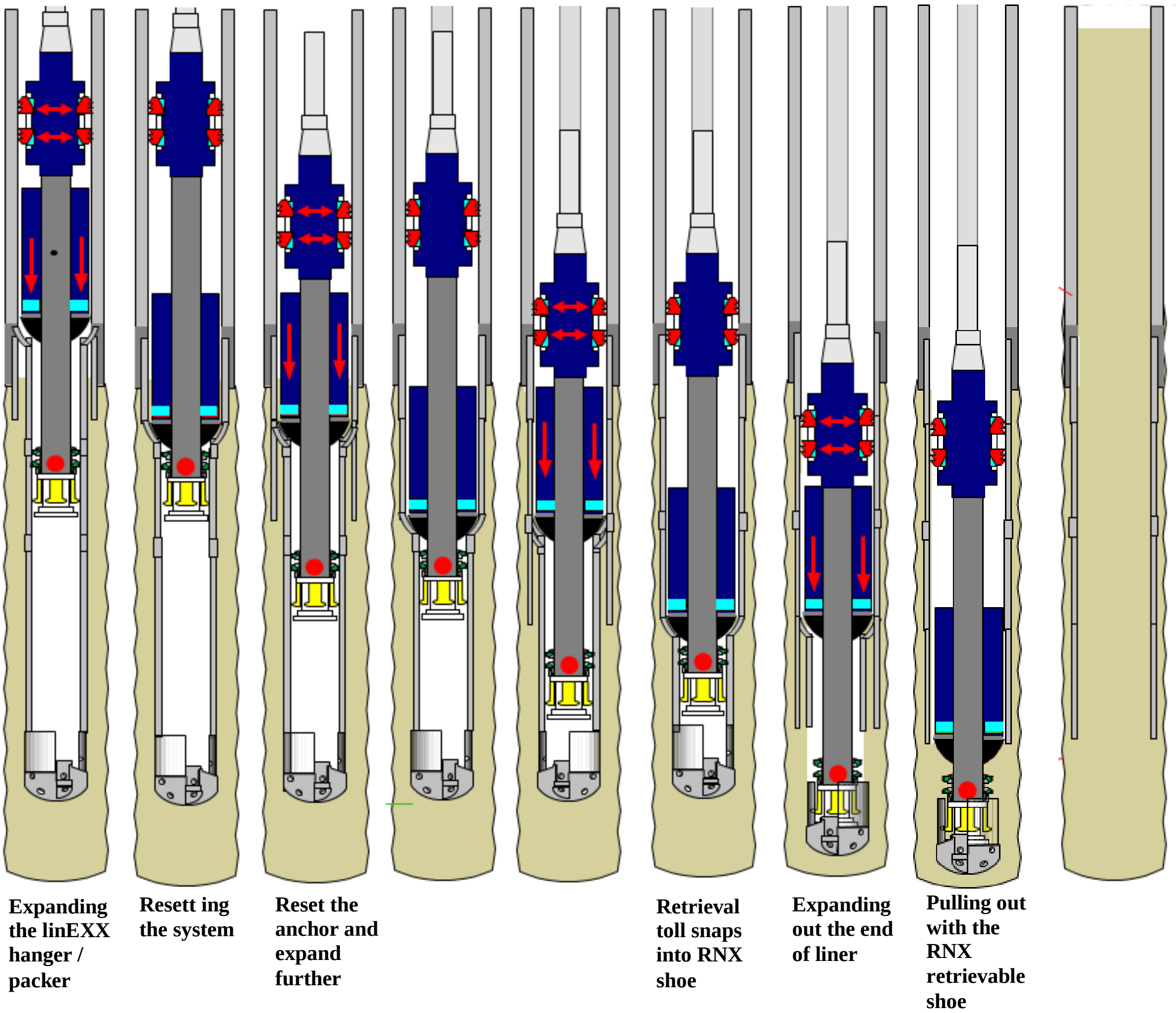


FIGURE 21: LINEXX™ EXPANSION SEQUENCE (BAKER HUGES, 2011)

5.3 Weatherford - *MetalSkin®* Solid Expandable

Weatherford MetalSkin® Solid Expandable Systems
Weatherford's new-generation MetalSkin® open- and cased-hole solid expandables offer ingenious ideas for well construction and remediation. New-generation MetalSkin® expandables minimize installation risks with smart ideas:

- Greater running clearance to avoid ECD and differential sticking
- Collapsible expansion cones for easy contingency retrieval
- Fully qualified premium metal-to-metal expandable connectors for unmatched high reliability
- Direct connection between work string and shoe for prevention of premature expansion
- Elastomer sealing elements for more positive zonal isolation
- Lower expansion-pressure requirement and high-integrity circulation valve for enhanced expansion reliability

MetalSkin® Solid expandable systems are custom built around your needs and backed by the global expandables network that includes two world-class manufacturing facilities and the industry's largest R&D, testing and training facilities.(Weatherford, 2012)

Weatherford offers:

- MetalSkin® Openhole liner
- MetalSkin® Monobore openhole liner
- MetalSkin® Monobore openhole clad
- MetalSkin® Casedhole liner system

5.3.1 Weatherford MetalSkin® Openhole liner system

Conventional casing running equipment and pressure pumping practices are used. Weatherford claims the process is no more complex than installing a conventional drilling liner. The system can be cemented or elastomers can be used for zonal isolation. If cement is planned, the hole needs to be opened by at least 1 1/2" in addition by under reaming.

Running sequence for Weatherford's MetalSkin® openhole liner system:

1. Make up the MetalSkin® system at surface, using conventional tubular makeup equipment, and run in hole to expansion depth. Condition and circulate the hole as required.
2. Drop ball. Once the ball lands, pressure up against it to form the expansion cone and launcher. Shear the ball seat to restore circulation.
3. Pump cement, and close the circulating valve in the expandable liner shoe to allow application of pressure against the upper expansion cups. The expansion cups pull the cone upward and initiate expansion.
4. Continue applying pressure to expand the liner. At any time during this process, the expansion can be suspended and the expansion tools retrieved to surface should an emergency situation arise.
5. Continue expansion into the liner overlap, where the elastomers on the expandable hanger create a seal.

6. Once the system is fully expanded, retrieve the drillstring and expansion tool to surface, and drill ahead.

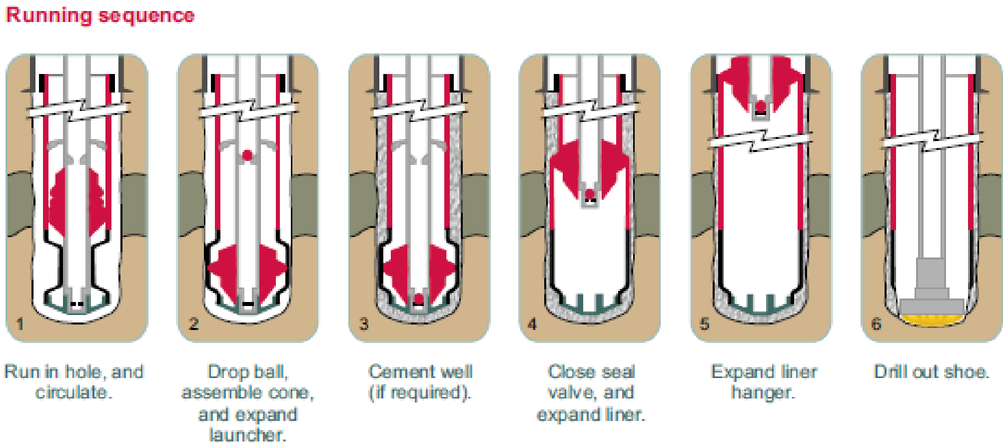


FIGURE 22: WEATHERFORD METALSKIN® RUNNING SEQUENCE. (WEATHERFORD, 2012)

5.4 Comparison of vendors

TABLE 3: COMPARISON OF VENDORS

	Enventure GT		BakerHughes		Weatherford
	SET technology		LinEXX high collapse monobore		MetalSkin
	7.625 x 9 7/8"	8.625 x 10 3/4"	cemented	non cemented	monobore open-hole liner
Bottom-up expansion			√	√	√
top-down expansion	√	√			
expansion tool	*mandrel*	*mandrel*	*rotating cone*	*rotating cone*	*rotating cone*
Toll left in hole to be drilleout	√	√			
Rathole			√	√	√
cemented	*pre expansion*	*pre expansion*	*post expansion*		
Base pipe Nominal OD ["]	*9.875*	*10.750*	*9.875*	*9.876*	
Base pipe API drift requirements ["]	*8.500*	*9.604*	*8.500*	*8.500*	
Recess shoe OD ["]			*11.250**	*10.250**	
Pilot hole ID	*8.500*	*8.501*	*8.500*	*8.500*	
Nominal open Hole ID	*11.000*	*11.001*	*10.250*	*9.750*	
Connection type	*GIIC*	*GHC*	*TenarisHydril 723 LH*	*TenarisHydril 723 LH*	
Gas tight					
Liner grade	*EX-80 (L-80)*	*EX-80 (L-80)*	*Sumitomo SX50*	*Sumitomo SX51*	
Pre exp. Nominal OD ["]	*7.625*	*8.625*	*8.000*	*8.001*	
Pre exp. Nominal ID ["]	*6.625*	*7.625*	*7.200*	*7.200*	
Pre exp. API drift ["]	*6.500*	*7.500*	*7.075*	*7.075*	
Pre exp. Internal Yield [psi]	*8970*	*7930*			
Pre exp. Burst rating [psi]			*5000*	*5000*	
Pre exp. Collapse strength [psi]			*3800*	*3800*	
Pre exp. Nominal yield strength [psi]	*80000*				
Pre exp. Weight [lb/ft]	*39.00*	*44.00*	*32.46*	*32.47*	
Post exp. Nominal OD ["]	*8.529*	*9.555*	*9.348*	*9.349*	
Post exp. Nominal ID ["]	*7.580*	*8.600*	*8.600*	*8.600*	
Post exp. API drift ["]	*7.504*	*8.514*	*8.500*	*8.500*	
Pre exp. Internal Yield [psi]	*7610*	*6840*			
Post exp. Burst rating [psi]			*5670*	*5670*	
Post exp. Collapse strength [psi]	*4570*	*3770*	*2309*	*2309*	
Post exp. Nominal yield strength [psi]					
Expansion Ratio [%]	*14.4*	*12.8*	*19.8*	*19.9*	
Liner shortening at bottom [%]	*0*	*0*	*5*	*6*	
Post exp. Nominal weight [lb/ft]	*40.51*	*45.93*			

6 Expandable technology in BP

6.1 Worldwide

The expandable technology, which involves the in-situ expansion of Oil Country Tubular Goods (OCTG), has steadily increased in utilization during the past 10 years. BP has employed the technology on numerous wells both onshore and offshore. In 2008, BP initiated a detailed review of solid expandable tubular (SET) technology used in the drilling of oil and gas producing wells. Previous reviews have been prepared, but this eight part review is designed to address the key issues involved so that BP drilling and completion engineers have the best available information on hand to make SET application evaluations and decisions. The report is prepared by engineering company Viking Engineering in collaboration with data obtained from Enventure. The report is approved by Bob Baker, EPT Solids Expandable Project Leader BP (BP, 2009). The review addresses the following subjects:

1. Effects of the length to diameter ratio in collapse testing.
2. Investigation of the Bauschinger Effect as it relates to expanded pipe.
3. Investigation of pipe-in-pipe collapse, i.e. the effect of SET collapse on conventional tubular.
4. Review of the performance properties of expanded pipe.
5. Review connection qualification tests.
6. Review vendor reliability systems.
7. Review of vendor QA/QC systems.
8. BP solid expandable specification.

6.2 Norway

Experience with expandable technology in BP Norway is limited to the installation of a casing patch delivered by Weatherford on the Ula field. The Skarv team has also earlier this year had discussions with Enventure about a SET liner in one of the shallower sections on one of the Skarv wells, but due to lack of time the discussion was not brought forward.

6.2.1 Expandable liner patch on ULA

6.2.1.1 Jobdescription

BP Norway contacted Weatherford early 2008 to come up with a solution for well A 12 on Ula where there was discovered a leakage in the 9 5/8" casing string. Weatherford proposed a 7 5/8" x 9 5/8" MetalSkin® Cased hole Liner (MCL) to be installed and seal of the leaking area. The MCL is an expandable casing patch which offers sealing solutions internal without adding much to the wall thickness and hence the ID reduction of the well is minimized. The well needed to be pressure tested to 5,500 psi (over sea water gradient) for future production operations. The MCL was considered a contingency if the pressure test failed and the cause of the failure was due to a leaking FOC stage collar.

The A12A 9 5/8" production casing is P-110, 53.5 ppf, special drift with New VAM connections. A Halliburton F.O. Cementer (F.O.C.) is located at 2018 m MD and was installed 20.05.1990. The casing was tested to 5000 psi 21.05.1990. A second stage 9 5/8" cement job was performed 02.06.1990 and casing re-tested to 5000 psi. A number of pressure tests and investigations during a workover in 1998 revealed an intermittent leak at the FOC stage cement collar. (BP, 2012)

The Weatherford objective was to install a single joint of 7 5/8" MetalSkin® Cased Hole Liner across the FO Cementer capable of withstanding 5,500 psi (at surface over sea-water gradient) of differential burst pressure at 150 °C. This patch will have an internal drift diameter of 7.475". The goals and results for the operation is listed in the table below.

TABLE 4: GOALS, REVIEW AND RESULTS (BP, 2012)

Goals	*Review/results*
Job Safety Analyses will be performed prior to all operations.	*No damages to tools or injury to people during operation*
JSA for the following the activities was prepared up front and	*Discussed offshore prior to P/U tools etc.*
Equipment preparation on deck	*All tools were prepared on deck to reduce rig time and risk to personnel.*
Pick up, make up and deployment of MCL	*Everything went according to plan.*
Expansion of MCL and tool retrieval	*Went according to plan, next time we need to evaluate using friction reducer in well prior to operation.*

6.2.1.2 Lessons learned

Job Design:
Liner top to first seal needs to be at least 5 feet to allow for fitting of slips and elevator.
Tubing connections hung up during subsequent running of upper completion bevel connections or add beveled stop-collars.

Tool design:
Use stronger jack: Evaluate making / using a new jack more suitable for the new type of expansion (MCL) Include grub-screws to prevent connections backing off.

Rig site:
Do not attach top drive while filling.
Extra pup-joints needed for easier handling.

During expansion:
Found overpull to be close to the maximum pulling capacity on the jack.
Consider using friction reducer to reduce expansion forces.

7 Casing design with expandable liner

As explained in section 4 one of the casing design constraints are the internal drift ID of the previous casing and the required internal drift ID for completion equipment to pass through. The completion equipment is designed to give the pay zone length to meet the required production rates. If the 9 7/8" casing, which have a drift ID of 8 ½", is to be kept and the section through Tilje needs to be 8 ½", it is not possible to install a conventional liner/casing to isolate Garn and Ile.

This problem, however, can be solved by the relatively new technology of expandable liner.

The objective of the expandable would be:

- Mitigate ID reduction
- Maintain wellbore stability during drilling the 8 ½" section
- Isolate Garn and Ile from Tilje
- Control Tilje well pressure while drilling 8 ½" section
- Be strong enough to endure all load scenarios
- Apply with Skarv Casing BOD.

The Skarv conventional casing design includes the 9 7/8" shoe to be placed in top Garn Fm and further drilling the three reservoir sections with an 8 ½" bit. Well J-4 however deviates from the Skarv BOD with respect to that the 9 7/8" shoe will be set into top Tilje Fm instead of top Garn Fm to ensure zonal isolation of the main reservoir. For these reasons, the J-4 well trajectory and casing design has been chosen as base case for the expandable liner casing design. For the expandable liner to be a solution for wells like J-4, the liner must comply with the J-4 well requirements.

7.1 Well J-4

The following is from the "J-4 Well construction basis of Design " (BP, 2012) which comply with the Skarv BOD and are basis for the expandable liner casing design.

7.1.1 J-4 well objectives

7.1.1.1 Strategic Objectives

1. Drill & complete the well with no accidents, no harm to people and no damage to the environment
2. Ensure zonal isolation between Garn, Ile & Tilje reservoirs
3. Deliver a gravel pack completion with minimal skin damage, ensuring production capacity of at least 7 mstb/day from Tilje reservoir
4. Deliver a well with 15 year well life

7.1.1.2 Technical Objectives

1. Penetrate Tilje L, K, J, H & F sands
2. Perform XLOT or LOT in top Tilje out of 9 7/8" casing shoe to determine formation strength

3. Collect pressure data to determine fluid gradient in Gråsel formation & Garn/Ile Fm. if drilled post production start

7.1.2 Objectives for expandable liner

1. Place the shoe into top Tilje reservoir
2. Isolation of HC bearing or permeable zone with flow potential if present in the B-annulus.
3. Maintain integrity of the cement sheath during life of well as a result of pressure and temperature effects during drilling operations, injection and/or production and final abandonment.
4. Allow for up to two deep set permanent abandonment plugs across the cemented section of the 9 7/8" casing. Either two plugs are required to isolate reservoir below, or if HC present behind 9 7/8" casing one plug for the lower reservoir and one plug above the upper HC zone.
5. Competent shoe and cement to provide the required formation strength at the shoe and above to allow subsequent drilling and production operations.
6. Withstand MEWHP from a tubing leak scenario, from either gas/oil production or gas injection.
7. Withstand the leak testing to MEWHP during green cement test and leak test during later well life with degraded mud.
8. Withstand drilling load scenario with lost circulation while drilling 8 ½" hole section.
9. Withstand collapse load created by B-annulus pressure as dictated by the rupture disk on the outer intermediate casing.
10. Withstand production load with fully evacuated casing below packer for gas producers and injectors.
11. Withstand production load with gas gradient to surface for oil producers below the packer.
12. Withstand production load or P&A load with partial evacuation above the packer equivalent to a fluid drop corresponding to the hydrostatic head of the fluid in equilibrium with the depleted pressure at reservoir.

7.1.3 Geological hazards

Risk / event	Impact	Action or mitigation
Cross flow between Tilje & Garn	Garn will eventually reach 4000psi differential pressure with respect to Tilje. Cross flow would result in oil loss into Garn fm. Zonal isolation is critical to well success.	Well design is changed to set 9 7/8" shoe into top Tilje. Cement across Ror & Not shales between Tilje & Garn will provide isolation. Well path entering from the east through fault A600 may help to mitigate by minimising Garn length.
Running casing over c.380mMD of significantly overbalanced reservoir section	Differential sticking of casing against Garn & Ile causes P&A and sidetrack.	Well design is to minimise Garn to Tilje section to limit exposure to high differential pressure. Unknown top Garn makes planning difficult in this respect, but J1 experience was OK. Running in to setting depth should be quick and with high focus from all crew.
Losses on cement job for 9 7/8" casing	Setting shoe in Tilje - require annular isolation of long well section with cement - over Garn, Ile & Gråsel. Unknown strength in Tilje may lead to losses during cement job and costly remedial action.	Cementing in Garn over long section has been no problem, but unknown strength in Tilje. No loses experienced on J1, but other difficulties with cement led to difficulties with TOC too deep to cover all required intervals.
Tilje comes in deep	If Tilje deep, reservoir target may be greatly reduced or even absent. Residual depth conversion issue means not resolved until Top Tilje.	Well path is prepared with deep Tilje outcome, but if depth even further outside the expected range then the target is not possible within given dogleg constraints and a sidetrack would be necessary.
Losses when pumping gravel pack in Tilje	XLOT data important to obtain Shmin in Tilje for pumping constraints during gravel-pack. Future depleted drilling needs accurate knowledge of fracture gradient.	Don't have XLOT in Tilje. Shmin is key input to completion planning for gravel pack - describes pump rate and thus how long the well can be.

FIGURE 23: GEOLOGICAL HAZARDS

7.1.4 Conventional casing design limitations

For the scope of this thesis, only information below the 13 5/8” shoe is evaluated to be of interest. The production casing is a tapered string. 150-175m of 10 3/4” casing is required under the wellhead to accommodate the 7” TRSCSSV (down hole safety valve) before crossing over to 9 7/8” casing. The internal drift of the 13 5/8” casing however allows for 10 ¾” casing to be installed all the way down and therefor this is evaluated as a casing design option for the expandable liner design. The option does not consider torque and drag.

7.1.5 J-4 well schematic

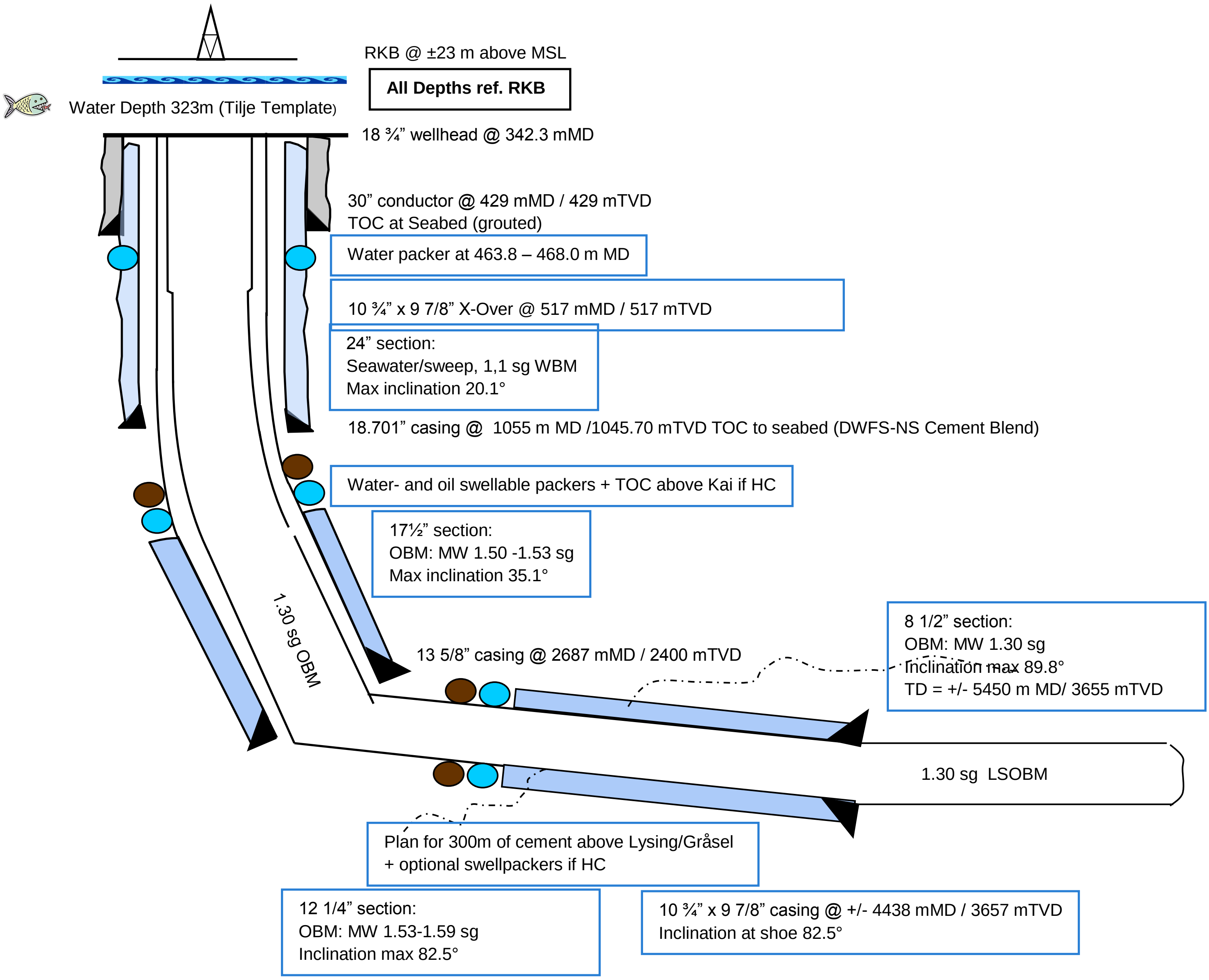


FIGURE 24: J-4 WELL SCHEMATICS (BP, 2012)

7.1.6 Expandable solutions for J-4

The expandable liner casing design options deviates from J-4 by setting the 9 7/8” shoe 400 mMD shallower in top Garn and installing an expandable liner 400m from the 9 7/8” casing shoe to Top Tilje. J-4 is a Tilje producer and has a 9 7/8” casing shoe set in Top Tilje with an openhole sand screen and gravel pack completion in the reservoir. The new design requires the 9 7/8” shoe to be set in top Garn, drill 8 ½ “ hole to Top Tilje, underream and install expandable liner from 9 7/8” shoe to Top Tilje

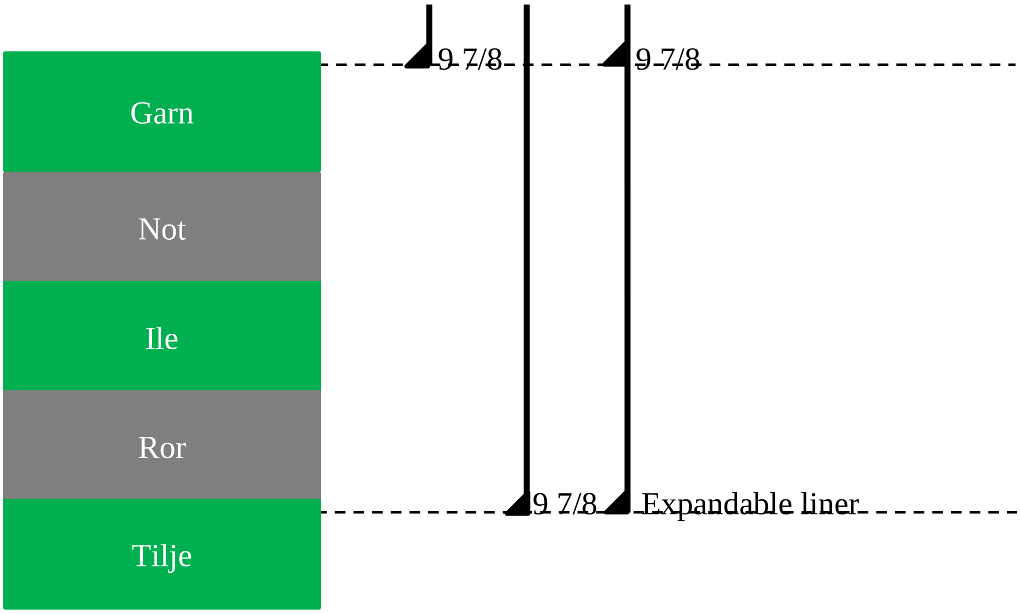


FIGURE 25: SKARV CASING DESIGN WITH EXPANDABLE LINER

Referring to the vendor section, section 5, the following design options have been identified as possible options for the Skarv field using Expandable liners in collaborations with the main suppliers of expandable technology. The design options apply with the Skarv casing design regarding dimension and installation limitations and requirements.

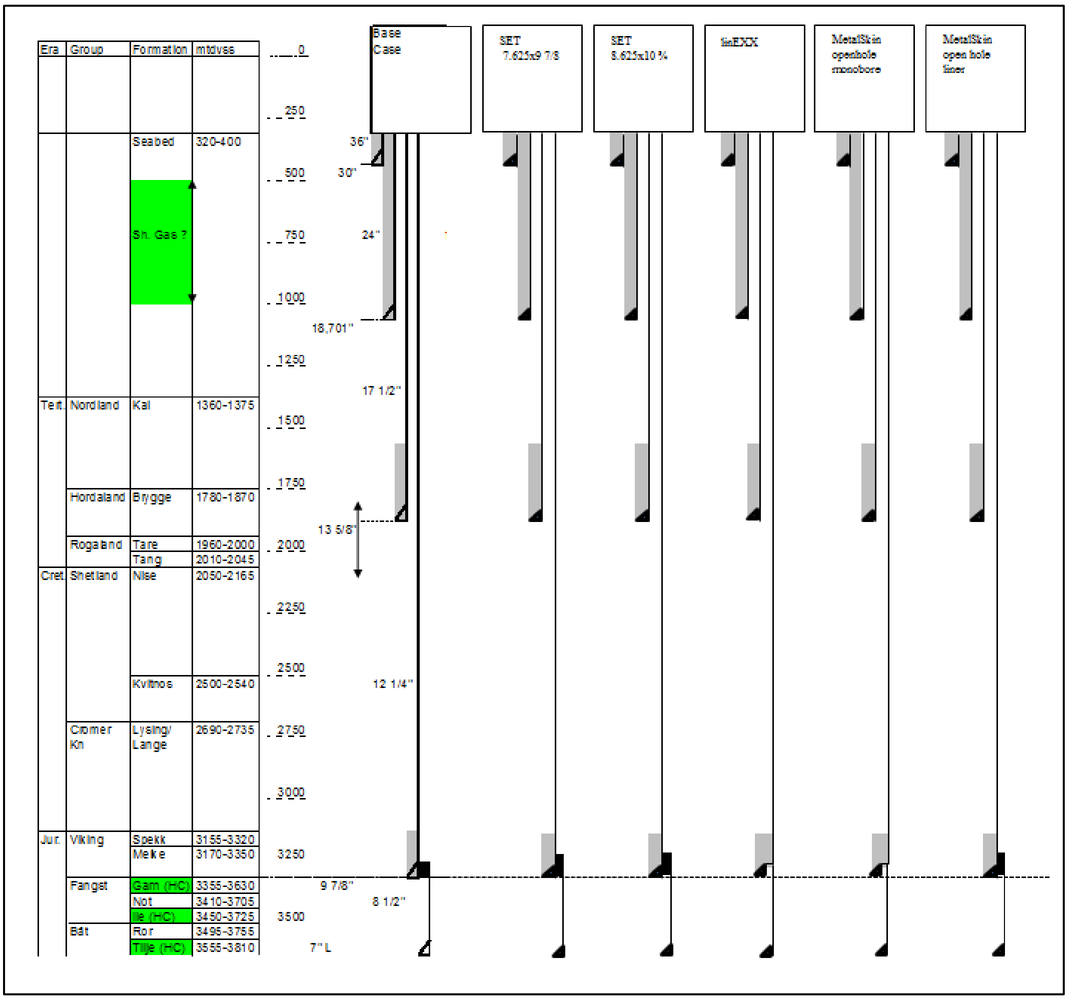


FIGURE 26: CASING DESIGN OPTIONS WITH EXPANDABLE TECHNOLOGY

7.1.7 7.625 x 9 7/8" Enventure SET® liner

This solution accommodates a 7.625" OD pre-installed liner to be installed through the 9 7/8" casing and expanded 14.4% to an 8.529" OD liner with a 7.504" drift ID. The liner is cladded to the 9 7/8" casing shoe by expanding elastomer sections that acts as the liners hanger.

This is a down-up expansion system which is cemented, if required, before expansion and must be fully expanded once the cement is in place. The liner is expanded hydraulically by pulling a cone. The launcher is left in the hole and this must be drilled out and possible underreamed.

7.1.8 8.625 x 10 ¾ Enventure SET® liner

This solution accommodates an 8.625" OD pre-installed liner to be installed through a 10 3/4" casing and expanded 12.8% to a 9.555" OD liner with an 8.514" drift ID. The liner needs a 10 3/4" base casing all the way down to top Garn. The liner is cladded to the 10 3/4" casing shoe by expanding elastomer sections that acts as the liners' hanger.

7.1.9 Baker Hughes *linEXX*^{TM} high collapse non cemented liner

The Baker Hughes *linEXX*^{TM} system is an 8.00” pre-installed monobore liner solution. A recess shoe is run on the previous casing to enable the expandable liner to be hanged off without any diameter reduction. The liner is suitable for a 9 7/8” base casing which will be run with a 7m 10 1/4” OD recess shoe. The recess shoe requires a minimum 10.250” hole which means the planned 12 1/4“ hole section is sufficient. The recess shoe is deigned such that the OD of the recess shoe does not exceed the connection OD of the liner and the recess shoe does hence not add any OD and can be installed through the previous casing drift ID. The liner is cladded to the recess shoe by a metal-to-metal seal that is initiated in the expansion process. The liner is expected to be expanded 19.8% with a resulting 5% liner shortening. The liner has an 8” OD pre expansion with 7.2” ID and 7.075 Drift ID. The liner requires a minimum drift of 8.5” through the previous casing.

7.1.10 Baker Hughes *linEXX*^{TM} high collapse cemented liner

The Baker Hughes *linEXX*^{TM} high collapse cemented system have the same dimensions as the un cemented system, but the recess shoe requires a larger hole section of minimum 11.250” OD recess shoe to account for the larger annulus needed for cement. All other dimensional and features are equal to the non-cemented system.

8 Design analysis

"The most important performance properties of casing are the axial tension, burst- and collapse pressure ratings. It is therefore important to calculate the axial tension loading, burst pressure scenarios and collapse scenarios that a casing might endure during installation and in the life of well. During installation, the casing is applied axial tension from the weight of the casing itself and by exceeding the body yield strength by applying tensional force, the casing can exceed its elastic limit. The minimal internal pressure that will cause the pipe to burst in the absence of axial loading and external pressure must be calculated". (API, 2012)

8.1 Introduction

Casing design is not only limited by dimensions but most often the load resistance capability of the tubular that is being installed. The cost of steel tubular in a well is a large percentage of the total well cost. To reduce the overall well cost, operators and well engineers try to limit the cost off the casing by detailed engineering to ensure that the minimum amount of tubular is installed without increased risk.

An important part of designing a casing is thus to calculate the actual and possible loads the casing or liner can be exposed to during installation, production and workover situations. This is performed with a worst case scenario approach meaning that if the casing can endure the worst case it can endure all other situations.

To identify the different load scenarios, basic casing design theory, NORSOK D-10 and BP internal guidelines are used.
The largest possible internal pressure and the smallest possible external pressure in burst situations are quantified and the lowest possible internal pressure and highest possible external pressure for collapse is quantified. Also kick and loss situations are calculated and axial loads from running and installation of the casing is calculated.

During and after installation the casing and liner tubular in the well are exposed to massive loads. Forces from drillstring, fluids, overburden, wellbore wall and tools can have large impact on the resistance ability of the tubular to withstand failure such as burst, collapse, buckling etc. An important part of selecting a solution is assessment of the load conditions applicable for each tubular string. Selection of design criteria is one of the most important aspects in designing a well. The worst case and most realistic scenarios for the specific well must be identified and critical limits must be calculated to find the most fit for purpose casing strings. The calculations involve strength assessment of burst- collapse and axial loading of the casing. For Skarv this has been done using the software StressCheck 2003.16.

API provides recommended formulas for computing these performance properties and the loads on the strings, but in the day to day work of a well engineer, software is used to ensure that the design can withstand the loading. BP well engineer use the software StressCheck to perform load calculations and Skarv basis of design is based on results from this software. It is therefore most beneficial to analyze the expandable in StressCheck if the expandable is to be implemented in the planned casing design for Skarv.

The Skarv basis of design is based on the B-5 well due to its long trajectory. The B-5 well however is a Garn producer and will not penetrate the lower Tilje formation. Therefor well J-4 is chosen as the base case for analysis since this well is a good represent for Tilje producers and this well is well analyzed in the software StressCheck and is a good representative to act as a reference and base case for the loads seen in the expandable liners. The results presented for J-4 Base Case is not simulated but extracted from the J-4 basis of design and are simulated by BP engineer Hanne Andersen. The J-4 basis of design is in agreements with BP specifications, NORSOK and the Skarv casing basis of design.

8.2 Design Challenges

One of the parameters in casing selection is the steel grade. Different steel grades have different properties and differs on a large scale when it comes to pressure ratings in collapse and burst direction, sour service and corrosion resistance. Standard oilfield tubular has a known steel grade. Expandable however alters its mechanical properties during the expansion process so that the pipes known properties pre-expansion is different from the post-expansion properties, meaning the expandable will have behave according to one steel grade and have burst and collapse limits before it is expanded and different steel grade behavior and burst and collapse strength after it is expanded. Since the tubular is expanded in-situ downhole, the actual end properties is unknown. There have been many studies, and several papers have been written concentrating on understanding the post expanded properties. The tubular are tested in laboratories and it is claimed by the vendor that the post expanded properties is known. The tubular must resist loads both as a pre-expanded and post-expanded pipe and load calculations for both "pipes" must be performed.

8.3 StressCheck

The software StressCheck Version 2003.16 has been used for the casing design analysis. StressCheck is Landmark *Software and Services* software provided by Halliburton. The software provides graphical design limit plots and safety factor for each string and models different pressure and axial load profiles in drilling and production events.
This software is chosen for this thesis because the current Skarv casing load analysis is performed using this software and it would be preferable for future casing design in BP Norway in general to be able to implement expandables into their design tool. Skarv casing design is based on results from this software.

A brief explanation of the load cases used in the analysis for Skarv follows in 8.10. Table 4.5 lists the load cases applicable for the specific casing string.

The *linEXX*™ and SET® options are simulated for load conditions. These options are chosen only by the collaboration by their vendors to supply input data. The Weatherford MetalSkin® is still considered as a solution when regarding dimensions and installation requirements.

8.4 Expandable in StressCheck

It is a common phrase that it is easy to put numbers into software and get numbers out, trusting the numbers is the knowledge. StressCheck is based on a conventional telescopic string design and will not allow a casing string to be followed by a string with larger dimensions than the drift ID of the previous casing. StressCheck analysis with expandable liners have been performed

before, Kumar el al from Statoil presented a paper based on StressCheck results with expandable design. However, to trust the results, a pre-design analysis was performed based on the assumption that the burst strength will slightly increase and the collapse strength will slightly decrease during expansion. This was done by designing to files, one including a pre-expanded tubular and the other the post expanded version of that tubular. By dividing the pre and post expanded tubular into to files and applying the assumption that the string of interest is not dependent on the string above in the software, a higher ID drift pipe was used as base pipe in the post expanded version. To gain confidence in the models, the Enventure SET® and the Baker Huhges linEXX™, which the vendors were kind to supply numbers, have been modeled both as pre and post expanded pipes and compared.
The expandable tubular do not have standard pipe properties that are already build in in StressCheck, so they were modeled by the use of the "special" pipe feature which allows the user to specify the burst and collapse strength, as specified by the vendor. The yield strength is however fixed to the chosen steel grade, so to alter the yield strength for the post expanded pipe, the steel grade was changed. It is expected that burst and collapse resistance is not dependent on the steel grade. The post expanded yield grade is believed to increase according to (Aadnøy, 2012) and the post expanded yield grade was increased by the same % as the expansion ratio.

8.4.1 Modeling of *linEXX*™ in StressCheck

LinEXX™ is expanded from top down, shrinking the expandable at the bottom. The pre expanded pipe was therefore modeled with an excessive length in relation to the expansion ratio to account for the shrinkage. It is not possible to increase the OD of strings downwards in StressCheck when the software is built on a telescopic casing design approach. To accommodate for the recess shoe that have an OD larger than the 9 7/8" casing ID drift, the entire 9 7/8" string section was set to have the drift ID of the recess shoe. This approach can be done when the string analyzed is not dependent on the string above.

Otherwise, all the files are based the same base case model based on the assumptions listed below. The numbers are from the Skarv casing basis of design and Skarv J-4 BOD. (BP, 2011)

8.4.2 Modeling of SET® in StressCheck

SET® is expanded bottom up and will shrink in the liner section. To accommodate for the shrinkage, the pre expanded hanger have an excessive length to accommodate for the shrinkage during expansion. The analysis results are from the string section between the 9 7/8" shoe down to the expandable shoe, but the excessive length was still accounted to visualize the expansion process. The common practice when installing a SET® liner is to cement only 70% of the post expanded annulus to ensure no debris is couth between the elastomer seal and base casing wall. If debris is left between the two, the sealing capability of elastomer sections can be lost. If the liner is to be fully cemented, debris catchers would be installed to mitigate the problem.

Otherwise, all the files are based the same base case model based on the assumptions listed below. The numbers are from the Skarv casing basis of design and Skarv J-4 BOD. (BP, 2011)

8.4.3 The base model

The 9 7/8" casing shoe is shortened 400m and set into top Garn and an expandable liner from the 9 7/8 shoe to top Tilje, the same 400m. The model is based on the J-4 trajectory. The packer in J-4 is at 4236 mMD which will be in the middle of the liner. If the expandable liner were to be installed it is most likely that the packer would be set in the 9 7/8" casing above the liner, but for initial analysis, the packer was left at 4236 mMD. In so way the results can be compare with the analysis results of the 9 7/8" casing to get an image of what happens with strength when a section of traditional casing is exchanged with an expandable tubular.

The data that are input to the model from the "J-4 Well construction basis of Design "are:

- Wellpath
- Geothermal gradient
- Initial pore pressure and fracture gradient
- Casing scheme down to 13 5/8" shoe
- Design factors

8.5 Assumptions

The load cases are performed with the following assumptions:

- The liner is installed from the Transocean semi-submersible drilling unit Polar Pioneer and the installation loads are based on the rigs requirements. Note that if a different rig is to be used, the load case parameters does not longer apply
- Contingency base casing options are not considered
- All temperature profiles are set to default in StressCheck

8.5.1 Design factors

Following Design factors have been used to comply with the already in use Skarv Casing BOD, NORSOK D-010 and BP internal specifications.

TABLE 5: MINIMUM DESIGN FACTORS (BP, 2012)

Load	BP Skarv Design Factor	BP Minimum Design factor	NORSOK D-010 Minimum Design factor
Axial	1.4	1.4	1.3
Burst	1.1	1.1	1.1
Collapse	1.0	1.0	1.0
Triaxial	1.25	1.25	1.25

8.5.2 Units of measurement

The Skarv Development shall use SI metric units. However, the main process flows shall also be expressed in BPD or MBD (liquids) and MMscfd (gas).

Table 6 gives an overview of the key units to be used:

TABLE 6: KEY UNITS TO BE USED FOR THE SKARV FIELD (BP, 2012)

Parameter	Unit
Pressure	Bar
Temperature	°C
Mass	Kg
Gas flow rate	Sm^3/d (scfd)[1]
Liquid Flow rate	Sm^3/d (BPD)[2]
Length	m
Viscosity	cP

[1] – MSm^3/d and MMscfd represent one million of base unit in the metric and English systems at standard conditions of temperature and pressure (15.56 °C. 1.01325 bar)
[2]- MBD may also be used to represent one thousand barrels per day at stock tank conditions

8.5.3 Lithology and formation tops

The wellpath is based on J-4 and the depth references given in StressCheck are the following:

TABLE 7: LITHOLOGY AND FORMATION TOPS J-4 (BP, 2012)

Event/Unit Top	m MDBRT	m TVD SS	+/-m Uncertainty (in TVD)	Comments
Sea Bed	346	323	0	Template depth, J template
Kai	1446	1360	20	Potential for elevated gas readings
Brygge	1973	1791	30	-
Tare	2201	1978	30	-
Tang	2259	2025	30	-
Paleogene Base (Nise)	2302	2060	30	-
Lysing	3011	2661	-25/+35	-
Gråsel sand	3308	2944	-	Expect oil reservoir
Spekk / BCU	3533	3149	30	Spekk may be absent in this location
Melke	3603	3209	30	Absent Spekk causes depth uncertainty
Garn	4058	3520	-	Gas reservoir
Not	4175	3571	-	Intra-reservoir shale

Tilje	4436	3634	15	Not possible to use above layers to adjust Top Tilje
TD (Tilje)	5450	3655	30	Tilje expected all oil

8.5.4 Fluids and depth references

TABLE 8: FLUID AND DEPTH DATA (BP, 2012)

Packer data	
Packer fluid density	1.180 sg
Packer depth	4236.00 mMD
Reservoir data	
Perforation depth	5450.19 mMD
gas/oil gravity	0.0800 psi/ft
Cementing data	
Mix-water density	0.990 sg
Lead Slurry Density*	13.77 ppg
Displacement Fluid Density	same as MW (sg)
Float collar depth	4436.70 mMD
Other	
fracture margin of error	0.05sg
Offshore subsea well	
Air gap	23mTVD
Water depth	323 mTVD

8.5.5 Overburden pore pressure and fracture gradient profiles

The following pressures are given in StressCheck

TABLE 9: PRESSURE (BP, 2012)

Formation / Unit	Minimum	Most Likely	Maximum	Comments
Garn	-	5484 psia 1.09sg	-	If present: Virgin reservoir pressure, well constrained with RCI measurements.
Ile	-	5505 psia 1.07sg	-	If present: Virgin reservoir pressure, well constrained with RCI measurements.
Tilje	-	5453 psia 1.05sg	-	Virgin reservoir pressure, well constrained with RCI measurements.

8.6 StressCheck load cases

The different pressure and axial load profiles identified as applicable to the expandable liner at the presented depth are modeled in StressCheck. The purpose is to simulate the drilling and production events used as basis for the casing design. A brief explanation of the load cases used in the analysis for Skarv follows in this section. Table 10 lists the load cases applicable for the specific casing string.

TABLE 10: LOADS APPLICABLE TO THE CASING STRINGS

Load case	Service Life Load Condition	SET® 7.625 x 9 7/8 Pre expanded	SET® 7.625 x 9 7/8 Post expanded	SET® 8.658 x 10 3/4 Pre expanded	SET® 8.658 x 10 3/4 Post expanded	linEXX uncemented pre expanded	linEXX uncemented post expanded	linEXX cemented pre expanded	linEXX cemented post expanded
	During Installation								
I1	Installing/Running Casing or Liner								
I2	Applying over pull force on string								
I3	Static load condition prior cementing operations								
I4	Static load condition post cementing operations								
I5	Pressure test after landing the plug, green cement								
	Burst Loads after Installation								
B1	Pressure test on casing/liner, determined by max. anticipated pressure in drilling phase								
B2	Pressure test on casing/liner, determined by max. anticipated pressure in production/service life								
B3	Well Control - gas filled casing/liner limited by FG gradient at shoe								
B7	Production - tubing leak with CIWHP applied on annulus, consider gas (oil) producers								
B8	Production - tubing leak with FWHP applied on annulus, consider gas/water inj, and stimulation								
B9	Production - Injection down the casing with kill fluid during well kill or workover.								
	Collapse Loads after Installation								
C3	Production - Plugged well/perforations - gas to surface for section below production packer (oil wells)								
C4	Production - Plugged well/perforations - full evacuation (gas wells)								
C5	Workover - Partial evacuation of casing/liner above production packer to (depleted) pore pressure								

8.6.1 Depletion

The cases are also analyzed for a depletion of 1000-4000 psi in Garn and with corresponding minimum mud weight to accommodate the wellbore stability issue.

The models include the expandable solutions that were identified as an option for Skarv.

8.7 Expandable liner technical Input parameters

The variable input parameters given from the supplier (technical sheet) are.

The details are presented in the technical sheets sin Appendix 1-3.

- Liner dimensions post and pre-expanded
- Hanger length pre -and post-expanded
- Liner grade
- Liner weight
- Nominal internal Yield
- Nominal OD
- Nominal ID
- API Drift ID

- Internal Yield /Burst rating
- Collapse Rating
- Expansion ratio

The Calculated input variables are:

- Liner length pre -and post-expanded
- Liner grade
- TOC

Liner length post expansion was calculated based on the expansion ratio where it was assumed that the shortening of the liner was the same as the expansion ratio; hence it is assumed that the expansion only affects the liner in longitudinal direction. This was done to accommodate for reduced liner hanger length post-expansion or reduced liner length post-expansion.

In some cases, liner grade was not given, but the nominal yield, and the grade was set in StressCheck to fit the nominal yield when StressCheck allows the user to set the grade but not the nominal yield value.

TOC was set to the liners length or 0 dependent on whether the liner was simulated as cemented or not.

Detailed input parameters and the values are presented in Appendix 4-6

8.8 Pressure

What usually is the limiting factor to whether the expandable liner could be installed or not is the strength of the expandable tubular compared to the forces in the borehole which is forces from pressure. Pore pressure can be estimated by looking at expected depletion rates which is a factor that can be controlled. Fracture pressure however is more complex and is often predicted by LOT values. Some fields have a long track record and have many LOT values that make it more reliable to predict the future fracture pressure. On Skarv, however, LOT values comes mainly from exploration wells and from a short time aspect which makes it difficult to predict the development. General models exist based on that the fracture pressure in some distinctive way follows the pore pressure, and the fracture gradient is calculated based on those assumptions.

The expandable liner will be installed cross a depleted reservoir. To simulate the depleted zone in a most realistic way, most likely future pressure profiles are found. A pore pressure curve and a fracture gradient curve for 4 different depleted scenarios are found. The overburden is constant and the reservoir pressure in Tilje is assumed constant. Skarv has a history of wellbore stability concerns, the mud weight have been calculated taking this into account.

8.8.1 Pressure prognosis

The depletion predictions for Skarv reservoir over time are:

Garn:

- 2000 psi in 3 years
- 3000 psi in 4,5 years
- 4000 psi in 9 years

Ile:

- 2000 psi in 4 years
- 3000 psi in 6 years
- 4000 psi in 12 years

Tilje:

- 1000 psi in 8 years
- 2000 psi in 9,5 years
- 3000 psi in 11 years

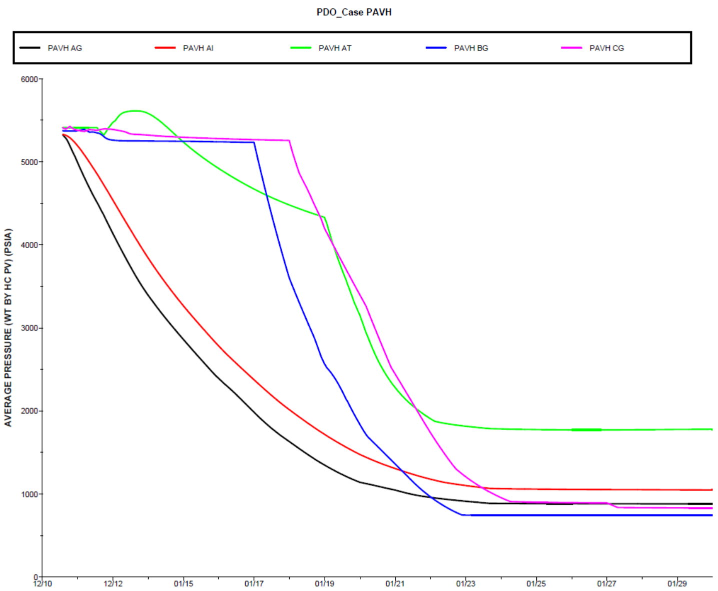


FIGURE 27: DEPLETION PREDICTION SKARV RESERVOIR (DUNCAN)

The prediction is based on the following assumptions:

- Garn will depleted with the rate of the black (lowest) curve in Figure 15
- Ile will deplete according to the red (highest) curve in Figure 15
- Tilje will remain constant due to pressure support by gas injection
- The sea water gradient is 1.03 sg. and the gas/water interface is at 3804 mTVD
- Top Garn is at 3543 mTVD, Top Ile at 3655 mTVD and Top Tilje at 3657 mTVD and top

The pressures are presented as most likely case. Pressure prognosis plot is presented in Appendix 8.

8.8.2 Garn pore pressure prediction

It is assumed that Garn will deplete 3000 psi in 3.5 years. It is therefore beneficial to estimate the pore pressure and fracture gradient for a depletion of 1000 psi - 4000 psi to cover the range off pressure regimes which an expandable can be installed.

The pore pressure input to the analysis has thus been found by using the following simplified equation:

Pore pressure depleted = pore pressure 2012 – x, 1000 psi< x > 4000 psi.

TABLE 11: GARN PORE PRESSURE PREDICTION INPUT TO STRESSCHECK

Reservoir pressure at 3542 mTVD			
	psi	**bar**	**Sg**
Initial (2012)	5484	379	1,09
Depleted 1000 psi	4484	309	0,89
Depleted 2000 psi	3484	240	0,69
Depleted 3000 psi	2484	171	0,49
depleted 4000 psi	1484	102	0,29

**J-4 is not yet drilled and the reservoir pressures are assumed to be analogue to J-3. Hence the pressure profiles presented are taken from well J-3.*

8.8.3 Fracture gradient

According to theory, the fracture pressure decreases when the pore pressure decreases. As stated earlier, the fracture pressure in Skarv is not easily predicted due to few LOT values. During discussions with BP's rock mechanical engineer Roar Flatebøe, simplified equations for the fracture gradient (FG)is sufficient for the scope of work in this thesis. The fracture gradient is calculated by equation 34 (EQ. 34).

8.8.4 Mud weight

Kumar and Marker et al. (2010) found that the collapse safety factor is sensitive to reasonable changes in the mud weight. The liner must therefore be analyzed for different mud weights.

Each pressure regime usually have a so called mud weight window (MWW) which is bounded by on the low side by the either the minimum required mud pressure to prevent shear failure on the wall, also called MW, min = collapse pressure or the pore pressure. On the high side, the MW should not exceed the fracture gradient. The mud weight must lie between these curves.

8.9 Wellbore stability

Today (2012) the reservoir sections are drilled with a large overbalance to be able to drill the high pressure Melke formation. This induces diff-stick issues. So far the drilling team has managed to drill successful wells, but when the reservoir depletes, this issue will increase and the limit will be exceeded if drilling with the current mud weight. Determining the proper mud weigh is important and simulating the expandable for the mud weight used is one off the essences of the calculations.
No wellbore stability curve for a depleted Garn is available or J-4 specific and had to be calculated to find the required mud weight. After advising with BP rock mechanical engineer Roar Flatebøe, it was found sufficient to calculate the well stability curves by Equation 26 (EQ. 26). Andersen found that the best fit equation for the Skarv field well stability were Equation 28 (EQ. 28) or/and Equation 29 (EQ. 29).

The wellbore stability curve was found for the initial pore pressure and depletion of 1000-4000 psi in Garn reservoir. The curves were calculated by Equation 26 through Equation 30 (EQ. 26 – EQ. 30). The Vp term in the equations is the p-wave velocity. There are no p-wave velocity data available for well J-4, so p-wave velocity and top table, which gives the formation top depths, for 5 surrounding wells, were compared and the best fit for well J-4 was extracted as input to the calculations.

8.10 Load cases

The design loads used in the stress analysis of the liner for well J-4 comply with the requirements of the BP Casing Design Manual.

The liner has been analyzed for installation, drilling and production loads. The load cases identified as applicable as a first approach is:

8.10.1 Installation Loads

Running casing:
Running in hole avg. speed: 0.242m/s (values from previous wells)

The maximum allowable overpull force is set to 100tonn for this string; the derrick rating on Polar Pioneer.

Conventional cement job
Cement and displacement fluid as listed above inTable 8. It is assumed that only one cement density will be used due to the relatively short interval. This operation is a collapse load case. Worst case will therefore be with the highest possible external pressure. A fully cemented annulus will provide the heaviest hydrostatic column prior to cement set.

Bumping plug and pressure test casing (green cement) for oil and gas producers
This is a burst load case. The pressure test should correspond to the highest pressure possibly seen by the casing. A maximum pore pressure of 1.05sg for Tilje at 3678 mTVD has been used. The common test pressure to use on Skarv well have been 345bar which also is used in the analysis. The test pressure for each pressure regime is also calculated in Table 14 in section 8.11.

An ‘artificial’ margin of error of 0.05sg was therefore added to account for the range in leak-off values.

8.10.2 Burst loads after installation

The external pressure is the same for all the burst load cases after the cement has set up; fluid gradient with degraded OBM, above TOC and fluid gradient w/pore pressure below TOC.

Pressure test for producers
This case is representative for pressure tests performed after the cement has set up. Internal pressure will be 345bar surface pressure with brine equal to the mud weight used in the specific case (see load case number 3 above for explanation of the pressure).

Drilling -well control with frac at shoe and gas gradient above shoe:
Internal pressure for this load case is Garn gas gradient (0.184sg) at fracture pressure from the shoe to WH.. A SF of 0.05sg is included to cover the range of leak-off values seen in this section.

Drilling -well control Lost returns with water:
Internal pressure for this load case is SW gradient from fracture point (shoe) to WH, mud weigh below shoe.

Drill ahead
Internal pressure is from the here mud weight.

Tubing leak gas and oil producers
Internal pressure is the reservoir pressure accounted for the hydrostatic gas column from production zone to WH in addition to the existing 1.18sg packer fluid.

Injection down casing for well kill or workover
Worst load case for the internal pressure will be closed WH with reservoir pressure trapped from TD to WH. The kick is bullheaded back into the formation with a kill fluid equal to the mud weight.

8.10.3 Collapse loads after installation

The external pressure is the same for all the collapse loads: fluid gradient with pore pressure below for the cemented liners and mud weight for the uncemented liners. Since the MW is higher than the pore pressure gradient a worst case for collapse will be uncemented cases.

Three different load cases with respect to collapse after the installation phase were analysed;

Lost circulation while drilling
Estimated mud drop level is based on a lost return depth of 5450 mMD with a pore pressure of 1.105sg EMW.

Drill ahead:
Same internal pressure as for the burst load, different external pressure (actual MW while running the string + set up cement).

Pressures above/below packer:
This load case is worst during production. Fluid drop may occur due to the hydrostatic head of the fluid equilibrating with the depleted pressure at the perforations. The internal pressure for the simulated case with depleted pressures will be fully evacuated casing below packer to gas gradient and partial evacuation above the packer with fluid drop to a PP of 1.05sg.

The packer will probably not be set in the expandable liner but as a first approach, the load case is analysed as part of the StressCheck reliability analysis.

8.10.4 Triaxial loads

This is the load that will be least accurate when analysing expandables in StressCheck when it is not possible to manipulate the grade.

8.10.5 Load case summary

The load cases used in the analysis is summarized in the Table 12 below. The loads are a first approach.

TABLE 12: LOAD CASES

#	Phase	Service Life Load Condition	Stresscheck Load Case	Comment
1	During Installation	**Running casing**	**Axial:** - Running speed - Applying over pull force on string - Static load condition prior to cement operation **Burst: N/A** **Collapse: N/A**	Max average running speed from previous runs + 10%SF is used; 0.242m/s. • Max overpull is set to100tonn
2	During Installation	**Conventional cement job**	**Axial:** - Static load condition prior to cement operation - Static load condition post cementing operation **Burst: N/A** **Collapse:** - Cement	• Worst case for collapse with wet cement in the full length of the liner
3	During Installation	**Bumping plug and pressure test casing (green cement)**	**Axial:** - Static load condition prior to cement operation - Static load condition post cementing operation - Pressure test after landing the plug, green cement **Burst:** - Green Cement Pressure Test **Collapse: N/A**	Tilje gas gradient 0.08psi/ft (0.184sg). . It is therefore sufficient to test the liner to 345bar.
4	Burst loads after installation	**Pressure test after the cement is set up (WOC or drilling next section)**	**Axial:** - Static load condition post cementing operation **Burst:** - Pressure test **Collpase: N/A**	• Same criteria as green cement pressure test.
5	Burst loads after installation	**Drilling - well control**	**Axial:** - Static load condition post cementing operation **Burst:** - Frac @ shoe with gas gradient above shoe **Collpase: N/A**	Expected LOT's = +/-2.00sg, Tilje gas gradient 0.08psi/ft =0.184sg, Fracture gradient SF of 0.05sg
6	Burst loads after installation	**Drilling - well control**	**Axial:** - Static load condition post cementing operation **Burst:** - Lost returns with water **Collpase: N/A**	Same case as above only with water filled wellbore.
7	Burst loads after installation	**Drill ahead**	**Axial:** - Static load condition post cementing operation **Burst:** - Drill ahead **Collpase: N/A**	• This particular load is required for strings that are not fully cemented in order to quantify how much buckling would occur on the uncemented section
8	Burst loads after installation	**Tubing Leak -gas&oil producers**	**Axial:** - Static load condition post cementing operation **Burst:** - Tubing Leak **Collpase: N/A**	•This load simulates a tubing leak at the WH. Internal pressure for the production casing is therefore reservoir pressure accounted for the hydrostatic gas column from production zone to WH in addition to the existing packer fluid.
9	Burst loads after installation	**Injection down string -well kill or workover**	**Axial:** - Static load condition post cementing operation **Burst:** - Injection down casing **Collpase: N/A**	Kill fluid in each case are equal to the respectively MW.
10	Collapse Loads after Installation	**Lost circulation while drilling**	**Axial:** - Static load condition post cementing operation **Burst: N/A** **Collpase:** - Lost circulation with mud drop	• Lost return depth 5450mMD
11	Collapse Loads after Installation	**Drill ahead**	**Axial:** - Static load condition post cementing operation **Burst: N/A** **Collpase:** - Drill ahead	• This particular load is required for strings that are not fully cemented in order to quantify how much buckling would occur on the uncemented section (prevents casing wear).
12	Collapse Loads after Installation	**Pressures Above/Below Packer**	**Axial:** - Static load condition post cementing operation **Burst: N/A** **Collpase:** - Above/Below Packer	• Fluid drop may occur due to the hydrostatic head of the fluid equilibrating with the depleted pressure at the perforations. Fully evacuated casing below packer to gas gradient.

8.11 Maximum expected Wellhead Pressure (MEWHP)

The actual required test pressure is pcalculated based on Maximum expected Wellhead pressure (MEWHP) principle. MEWHP will vary between individual wells depending on maximum pore pressure and formation strength.
MEWHP is calculated by the reservoir pressure in Tilje with a gas column to surface.

In Table 14, MEWHP is calculated for four different mud weights, calculated from EQ. 25. The calculations are based on data in Table 13. However has the production casing has been tested to 345bar surface pressure on all other wells and the expandable will as a base case be analyzed for this as well.

TABLE 13: INPUT TO MEWHP CALCULATIONS

Calculation basis		
Description	Value	unit
Tilje gas gradient*	0,184	sg
TVD	3678	mTVD
Expandable shoe	3657	mTVD
Seabed + air gap	346	mTVD
SF	10%	

**Assume Tilje gas gradient = Garn gas gradient*

TABLE 14: MAXIMUM EXPECTED WELLHEAD PRESSURE

Maximum Expected Wellhead Pressure (MEWHP).						
P_Tilje	MW	P at shoe	P at WH	P at surface	P_test	P-test + SF*
bar	bar	bar	bar	bar	bar	bar
384	1,3	384	325	280	309	**339**
384	1,1	384	325	287	316	**348**
384	1	384	325	291	320	**352**
384	0,8	384	325	297	327	**360**

**SF=10%*

9 Presentation of cases

The expandable liner differs from the regular casing or liner in mainly two ways, which is that the dimensions and load rating alters after the liner have been expanded. To account for these changes, two different files were set up, one where the pre-expanded liner were analyzed and one were the post-expanded liner was analyzed. The technical specifications of the tubular, the burst- and collapse ratings and the liner length (varies to accommodate the shortening during expansion) is the variables in the different cases. A summary of the input variables are presented in section 10.5. All the cases are based on a base case model modeled according to the assumptions and input data presented in section 9.

For simplification, the cases presented in the sections below are dedicated case numbers, which are listed in Table 15 below. All numbering of cases in this thesis refers to this table.

TABLE 15: STRESSCHECK CASES

Cases	
Case 1	7.625 x 9 7/8" Post exp Enventure SET®
Case 2	7.625 x 9 7/8" Post exp Enventure SET®
Case 3	8.625 x 10 3/4" Pre exp Enventure SET®
Case 4	8.625 x 10 3/4" Post exp Enventure SET®
Case 5	Pre exp high collapse non cemented linEXX™
Case 6	Post exp high collapse non cemented linEXX™
Case 7	Pre exp high collapse cemented linEXX™
Case 8	Post exp high collapse cemented linEXX™

9.1 SET® 7.625 x 9 7/8" Solid Expandable System

9.1.1 Case 1: SET® 7.625x 9 7/8" pre expanded liner

The SET® 7.625 x 9 7/8" pre expanded liner is modeled as a standard L-80 pipe according to the technical specifications by the vendor (the tech.sheet SET® liner grade is EX-80, which according to Enventure GT is analogue to L-80). The technical data sheet can be found in Appendix 1 and the input data to the StressCheck files are listed below in Table 16 and the casing and tubing scheme in Table 17 and in the well schematic in Figure 28. The base pipe is the 9 7/8"casing and the hole size is 11", which is the hole size required by the post expanded pipe (In such case, a 8 ½" pilot hole will be drilled and underreamed to 11.00"). The liner is cemented pre-expansion and it is assumed the liner will be fully cemented; hence TOC is at the previous casing shoe (at 4036 mMD). The liner will clad to the 9 7/8" shoe with elastomers, which will act as the hanger itself and top seal. According to Enventure GT, there is no standard length of the elastomer liner section. This is there for assumed to be 100m which is a typical liner length in similar wells. The casing and tubing scheme down to the 9 7/8" shoe and the 6 5/8" completion string is as for well J-4. The liner is analyzed for mud weights 1.3sg, 1.1sg, 1.0sg and 0.8sg in five different pressure regimes according to the Garn depletion prediction presented in section 8.8.1.

TABLE 16: 7.625 X 9 7/8" ENVENTURE SET® PRE EXPANDED STRING SECTION

String section										
OD	Weight	Grade	ID	Yield	Int Drift	Pipe Type	Burst	Collapse	Axial	UTS
(in)	(ppf)	-	(in)	(bar)	(in)	Type	(bar)	(bar)	(daN)	(bar)
7.625	39.000	L-80	6.625	5515.81	6.500	Standard	632.961	607.841	398273.3	6550.02

TABLE 17: 7.625 X 9 7/8" ENVENTURE SET® PRE EXPANDED CASING AND TUBING SCHEME

7.625 x 9 7/8" Enventure SET® Pre Expanded Casing and tubing scheme							
OD (in)	Name	Type	Hole Size (in)	Measured Depths (m)			Mud at shoe (sg)
				Hanger	Shoe	TOC	
30"	Conductor	Casing	36.00	342.0	429.3	342.0	1.03
	Surface	Casing	24.00	341.5	1055.5	342.0	1.30
13 5/8"	Intermediate	Casing	17.50	341.0	2687.0	2387.0	1.53
9 7/8"	Production	Casing	12.25	340.5	4036.7	2940.0	1.59
7 5/8"	Production	Liner	11.00	3936.7	4436.7	4036.0	1.30 - 0.80
6 5/8"	Production	Liner	8.50	4436.0	5450.0	5450.0	1.30 - 0.80

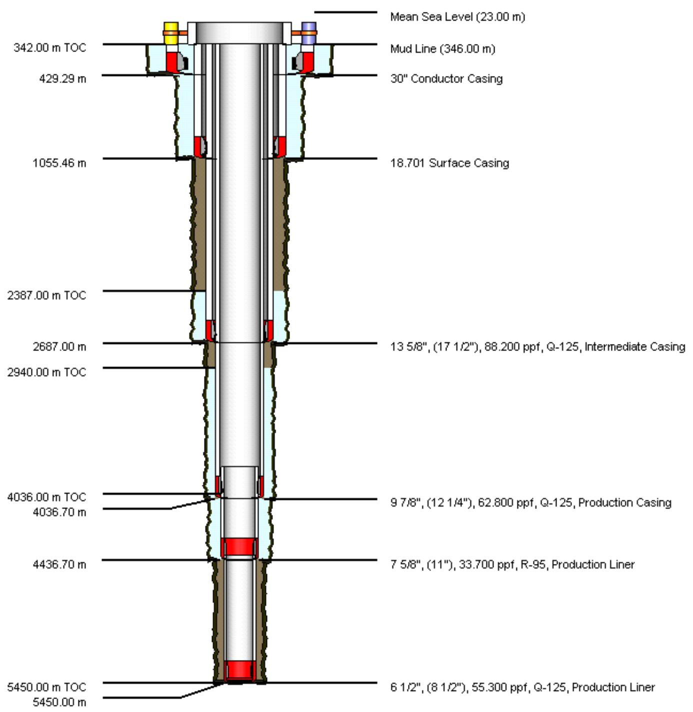


FIGURE 28: 7.625 X 9 7/8" SET® LINER PRE EXPANDED WELL SCEMATIC

9.1.2 Case 2: SET® 7.625x 9 7/8" post expanded liner

The SET® 7.625 x 9 7/8" post expanded liner is modeled as a special X-70 pipe to simulate the technical specifications by the vendor. The technical data sheet can be found in Appendix 1 and the input data to the StressCheck files are listed below in Table 16 and the casing and tubing scheme in Table 19 and in the well schematic in Figure 29. The expansion ratio is 14.4%. The base pipe is the 9 7/8" casing and the hole size is 11", which is the hole size required by the post expanded pipe (In such case, a 8 ½" pilot hole will be drilled and underreamed to 11.00"). The liner is cemented pre expansion and it is assumed the liner will be fully cemented; hence TOC is at the previous casing shoe (at 4036 mMD). The model has not accounted for excess cement volumes due to annulus reduction after expansion.

The system is a bottom-up expansion where the shrinkage is at top. This is accounted for by shortening the post-expanded liner length according to the expansion ratio. The casing and tubing scheme down to the 9 7/8" shoe and the 6 5/8" completion string is as for well J-4. The liner is analyzed for mud weights 1.3sg, 1.1sg, 1.0sg and 0.8sg in five different pressure regimes according to the Garn depletion prediction presented in section 8.8.1.

TABLE 18: 7.625 X 9 7/8" ENVENTURE SET® POST EXPANDED STRING SECTION

String section										
OD	Weight	Grade	ID	Yield	Int Drift	Pipe Type	Burst	Collapse	Axial	UTS
(in)	(ppf)	-	(in)	(bar)	(in)	Type	(bar)	(bar)	(daN)	(bar)
8.529	40.510	X-70	7.580	4826.33	7.504	Special	525.000	315.000	427268.7	5653.70

TABLE 19: 7.625 X 9 7/8" ENVENTURE SET® POST EXPANDED CASING AND TIBING SCHEME

7.625 x 9 7/8" Enventure SET® Post Expanded Casing and tubing scheme							
OD (in)	Name	Type	Hole Size (in)	Measured Depths (m)			Mud at shoe (sg)
				Hanger	Shoe	TOC	
30"	Conductor	Casing	36.00	342.00	429.29	342.00	1.03
	Surface	Casing	24.00	341.50	1055.46	342.00	1.30
13 5/8"	Intermediate	Casing	17.50	341.00	2687.00	2387.00	1.53
9 7/8"	Production	Casing	12.25	340.50	4036.70	2940.00	1.59
8.529	Production	Liner	11.00	3940.70	4436.70	4036.00	1.30 - 0.80
6 5/8"	Production	Liner	8.50	4436.00	5450.00	5450.00	1.30 - 0.80

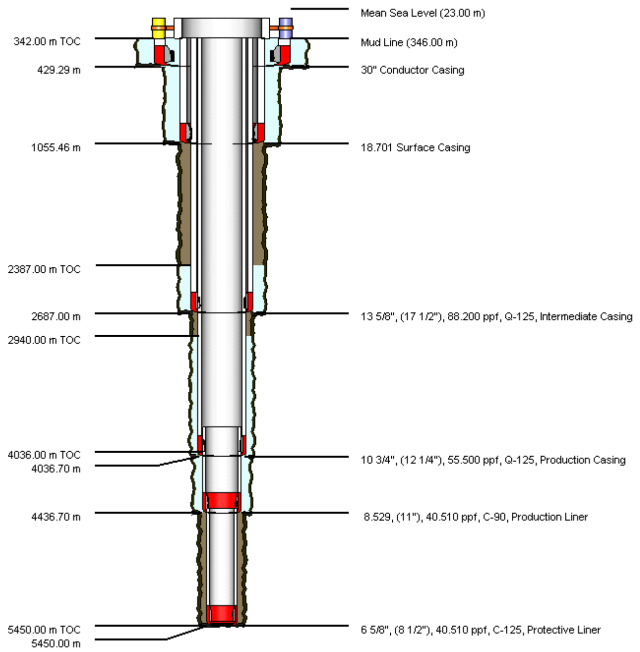


FIGURE 29: 7.625 X 9 7/8" SET® LINER POST EXPANDED WELL SCEMATIC

9.2 SET® 8.625 x 10 ¾" Solid Expandable System

9.2.1 Case 3: SET® 8.625 x 10 ¾" pre expanded liner

The SET® 8.625 x10 ¾" pre expanded liner is modeled as a standard L-80 pipe according to the technical specifications by the vendor(the tech.sheet SET® liner grade is EX-80, which according to Enventure GT is analogue to L-80). The technical data sheet can be found in Appendix 2 and the input data to the StressCheck files are listed below in Table 20 and the casing and tubing scheme in Table 21 and in the well schematic in Figure 30. The liner requires a 10 ¾" base pipe and 11" hole size, which is the hole size required by the post expanded pipe (In such case, pilot hole will be drilled and underreamed to 11.00"). The liner is cemented pre expansion and it is assumed that the liner will be fully cemented; hence TOC is at the previous casing shoe (at 4036 mMD). The liner will clad to the 10 ¾" shoe with elastomers, which will act as the hanger itself and top seal. According to Enventure GT, there is no standard length of the elastomer liner section. This is there for assumed to be 100m which is a typical liner length in similar wells. The casing and tubing scheme down to the 13 5/8" shoe and the 6 5/8" completion string is as for well J-4. In the original J-4 casing scheme, the 10 ¾" casing is crossed over to 9 7/8" casing, but to accommodate for the required base casing ID for this SET® option, the 10 ¾" casing is installed all the way down to top Garn (at 4036 mMD). The liner is analyzed for mud weights 1.3sg, 1.1sg, 1.0sg and 0.8sg in five different pressure regimes according to the Garn depletion prediction presented in section 8.8.1.

TABLE 20: 8.625 X 10 ¾" ENVENTURE SET® PRE EXPANDED STRING SECTION

String section										
OD	**Weight**	**Grade**	**ID**	**Yield**	**Int Drift**	**Pipe Type**	**Burst**	**Collapse**	**Axial**	**UTS**
(in)	**(ppf)**	**-**	**(in)**	**(bar)**	**(in)**	**Type**	**(bar)**	**(bar)**	**(daN)**	**(bar)**
8.625	44.000	X-80	7.625	5515.81	7.500	Standard	559.575	479.068	454171.3	6205.28

TABLE 21: 8.625 X 10 ¾" ENVENTURE SET® PRE EXPANDED CASING AND TIBING SCHEME

8.625 Enventure SET Pre Expanded Casing and tubing scheme							
OD (in)	**Name**	**Type**	**Hole Size (in)**	**Measured Depths (m)**			**Mud at shoe (sg)**
				Hanger	**Shoe**	**TOC**	
30"	Conductor	Casing	36.00	342	429.29	342	1.03
	Surface	Casing	24.00	341.5	1055.46	342	1.30
13 5/8"	Intermediate	Casing	17.50	341	2687	2387	1.53
10 3/4"	Production	Casing	12.25	340.5	4036.7	2940	1.59
8 5/8"	Production	Liner	11.00	3936.7	4436.7	4036	1.30 - 0.80
6 5/8"	Production	Liner	8.50	4436.00	5450.00	5450.00	1.30 - 0.80

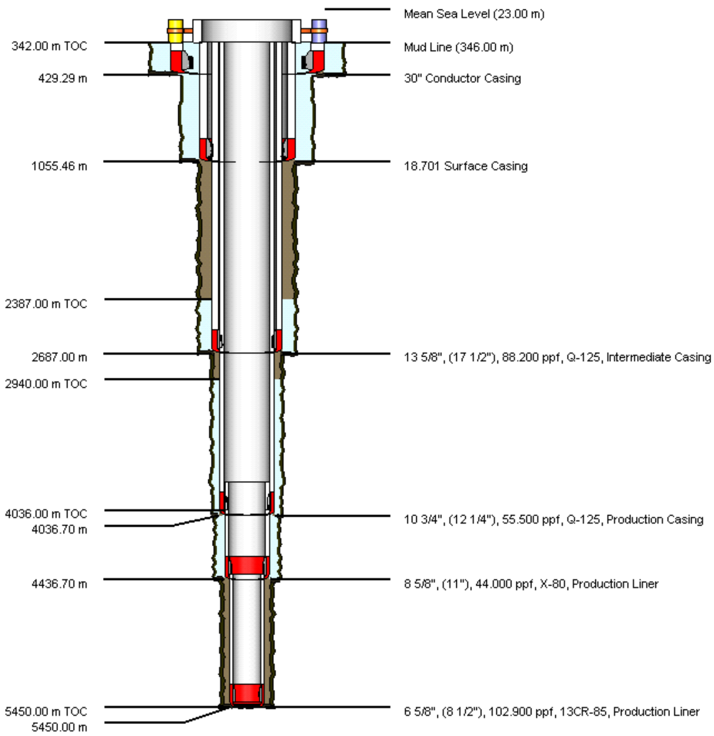


FIGURE 30: 8.625 X 10 ¾ SET® PRE EXPANDED LINER WELL SCHEMATIC

9.2.2 Case 4: SET® 8.625 x 10 ¾ post expanded liner

The SET® 8.625x10 ¾" post expanded liner is modeled as a special C-90 pipe to simulate the technical specifications by the vendor. The technical data sheet can be found in Appendix 2 and the input data to the StressCheck files are listed below in Table 20 and the casing and tubing scheme in Table 23 and in the well schematic in Figure 31. The expansion ratio is 12.8%. The base pipe is the 10 ¾" casing and the hole size is 11", which is the hole size required by the post expanded pipe (In such case, a 8 ½"pilot hole will be drilled and underreamed to 11.00"). The liner is cemented pre expansion and it is assumed the liner will be fully cemented; hence TOC is at the previous casing shoe (at 4036 mMD). The model have not accounted for excess cement volumes due to annulus reduction after expansion.

The casing and tubing scheme down to the 13 5/8" shoe and the 6 5/8" completion string is as for well J-4. In the original J-4 casing scheme, the 10 ¾" casing is crossed over to 9 7/8" casing, but to accommodate for the required base casing ID for this SET option, the 10 ¾" casing is installed all the way down to top Garn (at 4036 mMD). The liner is analyzed for mud weights 1.3sg, 1.1sg, 1.0sg and 0.8sg in five different pressure regimes according to the Garn depletion prediction presented in section 8.8.1.

TABLE 22: 8.625 X 10 ¾ POST EXPANDED SET® STRING SECTION

String section										
OD	Weight	Grade	ID	Yield	Int Drift	Pipe Type	Burst	Collapse	Axial	UTS
(in)	(ppf)	-	(in)	(bar)	(in)	Type	(bar)	(bar)	(daN)	(bar)
9.555	45.930	X-70	8.600	4826.33	8.514	Special	471.600	259.900	424007.9	5653.70

TABLE 23: CASING AND TUBING SCHEME 8.625 X 10 ¾ POST EXPANDED SET®

8.625 Enventure SET Pre Expanded Casing and tubing scheme							
OD (in)	Name	Type	Hole Size (in)	Measured Depths (m)			Mud at shoe (sg)
				Hanger	Shoe	TOC	
30"	Conductor	Casing	36.00	342	429.29	342	1.03
	Surface	Casing	24.00	341.5	1055.46	342	1.30
13 5/8"	Intermediate	Casing	17.50	341	2687	2387	1.53
10 3/4"	Production	Casing	12.25	340.5	4036.7	2940	1.59
9.555	Production	Liner	11.00	3936.7	4436.7	4036	1.30 - 0.80
6 5/8"	Production	Liner	8.50	4436.00	5450.00	5450.00	1.30 - 0.80

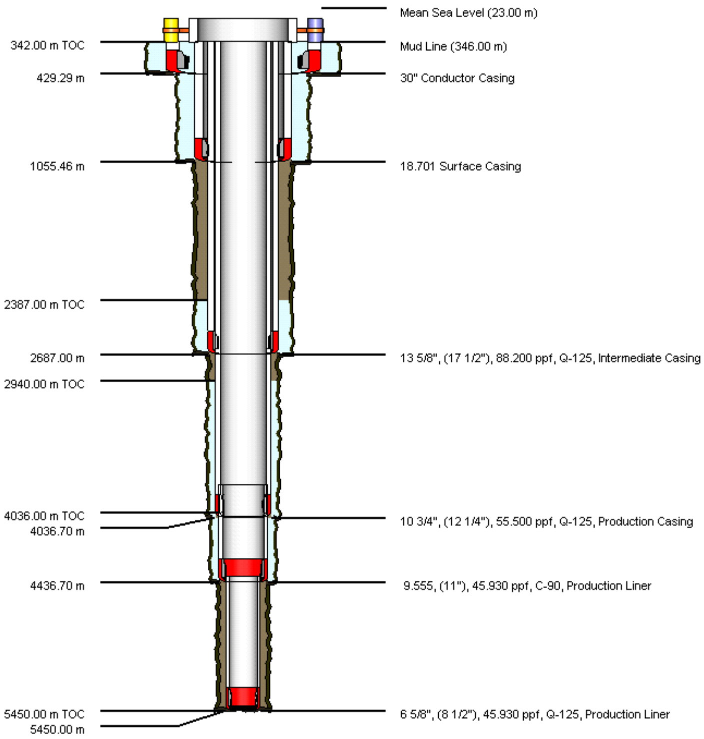


FIGURE 31: 8.625 X 10 ¾" SET® POST EXPANDED LINER WELL SCHEMATIC

9.3 linEXX^{TM} system monobore casing extension High collapse cemented

9.3.1 Case 5: linEXX™ high collapse cemented pre expanded

The linEXX™ high collapse cemented pre expanded liner's pipe metallurgy is specified as Sumitomo SX50, which is not a default in StressCheck. The liner is there for modeled as X-52 which are the grade that have the most similar yield rating. The pipe was set to special pipe which allows setting the collapse and burst ratings. Liner dimensions is given as specified in *linEXX^{TM}* system Specification Guide in Appendix 3 and the input data to the StressCheck files are listed below in Table 24 and the casing and tubing scheme in Table 25 and in the well schematic in Figure 32. The connection type is TenarisHydril 723 LH.

The liner requires a 9 7/8" base pipe with a 11 ¼" recess shoe and minimum 10 1/4" hole size, which is the hole size required by the post expanded pipe (In such case, pilot hole will be drilled and underreamed to 10 1/4"). The top down expansion induces shortening at bottom. The liner is expected to be expanded 19.8% and a 5% liner shortening is expected. To ensure 400m liner after expansion, 420m liner must be installed to account for the shortening (If the liner is to be installed in a well, a rathole must be drilled to accommodate excess liner length). The cladded section in the recess shoe acts as hanger and top seal. The hanger section is 7m, resulting in a 427m liner where the hanger top is at 4029.7 mMD and shoe at 4456.7 mMD. The liner is expanded prior to cementing. TOC is set at 4436.7, giving 0m cement interval to simulate non cemented liner. The burst rating is 344.737bar and collapse rating 262bar. The liner weight is 32.46 lb. /ft. The liner has an 8" OD pre-expansion with 7.2" ID and 7.075 Drift ID. The hanger loads are 5670psi and 2309psi for burst and collapse respectively, thus higher than the liner. The connection type is TenarisHydril 723 LH with a maximum 8.288" OD. The liner has an 8" OD pre expansion with 7.2" ID and 7.075 Drift ID. The casing and tubing scheme down to the 9 7/8" shoe and the 6 5/8" completion string is as for well J-4. The liner is analyzed for mud weights 1.3sg, 1.1sg, 1.0sg and 0.8sg in five different pressure regimes according to the Garn depletion prediction presented in section 8.8.1.

TABLE 24: LINEXX™ HIGH COLLAPSE PRE EXPANDED CEMENTED STRING SECTION

String section										
OD	Weight	Grade	ID	Yield	Int Drift	Pipe Type	Burst	Collapse	Axial	UTS
(in)	(ppf)	-	(in)	(bar)	(in)	Type	(bar)	(bar)	(daN)	(bar)
8.000	32.460	X-52	7.200	3585.27	7.075	Special	344.737	262.000	297377.4	4550.54

TABLE 25: LINEXX™ HIGH COLLAPSE PRE EXPANDED CEMENTED CASING AND TUBING SCHEME

8.625 Enventure SET Pre Expanded Casing and tubing scheme							
OD (in)	Name	Type	Hole Size (in)	Measured Depths (m)			Mud at shoe (sg)
				Hanger	Shoe	TOC	
30"	Conductor	Casing	36.00	342	429.29	342	1.03
	Surface	Casing	24.00	341.5	1055.46	342	1.30
13 5/8"	Intermediate	Casing	17.50	341	2687	2387	1.53
10 3/4"	Production	Casing	12.25	340.5	4036.7	2940	1.59
8 5/8"	Production	Liner	10.25	4029.7	4436.7	4436.7	1.30 - 0.80
6 5/8"	Production	Liner	8.50	4436.7	5450	5450	1.30 - 0.80

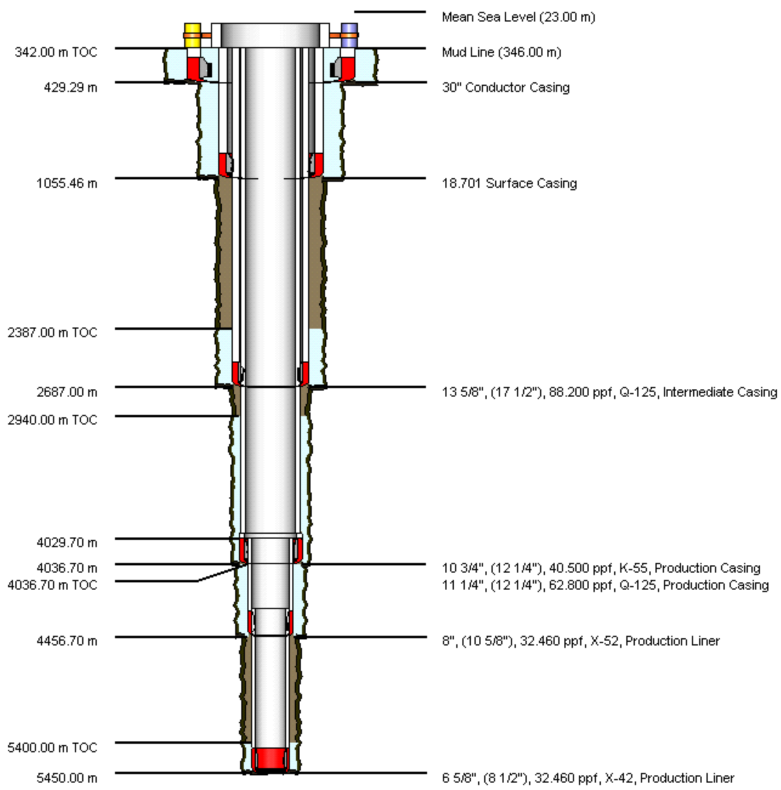


FIGURE 32: LINEXX™ HIGH COLLAPS CEMENTED PRE EXPANDED WELL SCHEMATIC

9.3.2 Case 6: linEXX™ high collapse cemented post expanded

The linEXX™ high collapse post expanded liner is modeled as T-95 to simulate the technical specifications by the vendor. The connection type is TenarisHydril 723 LH. The technical data sheet can be found in Appendix 3 and the input data to the StressCheck files are listed below in Table 26 and the casing and tubing scheme in Table 27 and in the well schematic in Figure 33. The liner requires a 9 7/8” base pipe with a 11 ¼” recess shoe and 10 1/4" hole size, which is the hole size required by the post expanded pipe (In such case, pilot hole will be drilled and underreamed to 10 1/4"). This system is a top-down expansion, and the liner will shrink at bottom due to expansion. This mean that excess length of the pre expanded pipe is required to ensure the post expanded length of the liner. This is accounted for in the model by adding length at bottom of the liner to the pre expanded pipe. If the liner is to be installed in a well, a rat hole must be drilled to accommodate excess liner length. It is assumed the liner will shrink according to the expansion ratio of 19.8% The liner is cemented pre expansion and it is assumed the liner will be fully cemented, hence TOC is at the previous casing shoe (at 4036 mMD). The liner will clad to the recess shoe by metal to metal seal, which will act as the hanger itself and top seal. The liner hanger length is 7m. The casing and tubing scheme down to the 9 7/8” shoe and the 6 5/8” completion string is as for well J-4. The liner is analyzed for mud weights 1.3sg, 1.1sg, 1.0sg and 0.8sg in five different pressure regimes according to the Garn depletion prediction presented in section 8.8.1.

TABLE 26: LINEXX™ HIGH COLLAPSE POST EXPANDED CEMENTED STRING SECTION

String section										
OD	Weight	Grade	ID	Yield	Int Drift	Pipe Type	Burst	Collapse	Axial	UTS
(in)	(ppf)	-	(in)	(bar)	(in)	Type	(bar)	(bar)	(daN)	(bar)
9.348	29.030	T-95	8.600	6550.02	8.500	Special	390.930	159.200	375218.2	7239.50

TABLE 27: LINEXX™ HIGH COLLAPSE POST EXPANDED CEMENTED CASING AND TUBING SCHEME

linEXX™ high collapse cemented pre expanded							
OD (in)	Name	Type	Hole Size (in)	Measured Depths (m)			Mud at shoe (sg)
				Hanger	Shoe	TOC	
30"	Conductor	Casing	36.00	342	429.29	342	1.03
	Surface	Casing	24.00	341.5	1055.46	342	1.30
13 5/8"	Intermediate	Casing	17.50	341	2687	2387	1.53
10 3/4"	Production	Casing	12.25	340.5	4036.7	2940	1.59
9.348"	Production	Liner	10.25	4029.7	4436.7	4036	1.30 - 0.80
6 5/8"	Production	Liner	8.50	4436	5450	5450	1.30 - 0.80

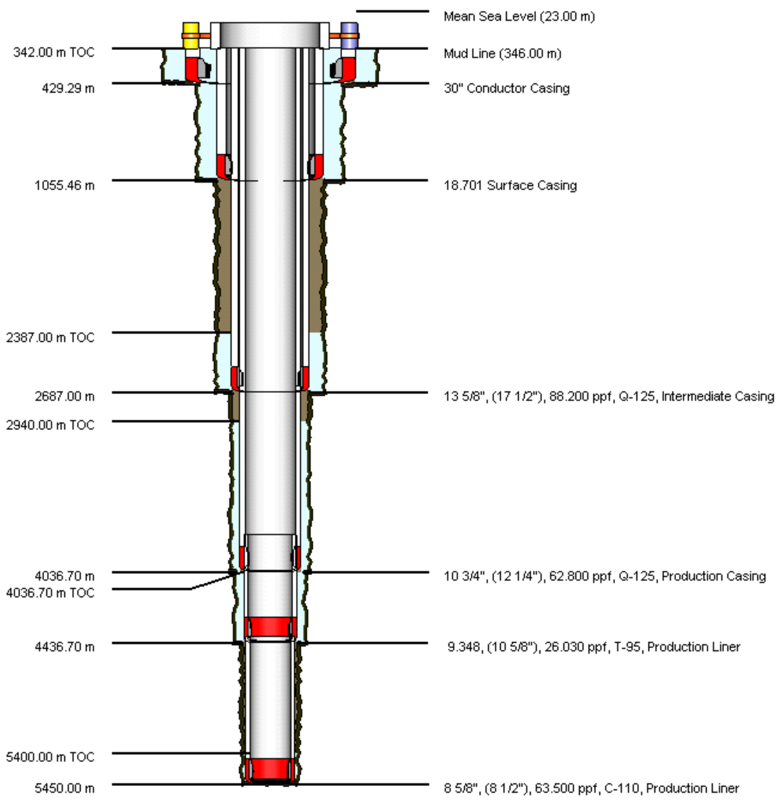


FIGURE 33: LINEXX™ HIGH COLLAPS CEMENTED POST EXPANDED WELL SCHEMATIC

9.4 linEXX^{TM} system monobore casing extension high collapse non-cemented

9.4.1 Case 7: linEXX high collapse non-cemented pre expanded

The linEXX™ high collapse non-cemented pre expanded liner's pipe metallurgy is specified as Sumitomo SX50, which is not a default in StressCheck. The liner is there for modeled as X-52 which are the grade that have the most similar yield rating. The connection type is TenarisHydril 723 LH. The technical data sheet can be found in Appendix 3 and the input data to the StressCheck files are listed below in Table 28 and the casing and tubing scheme in Table 29 and in the well schematic in Figure 34. The liner requires a 9 7/8" base pipe with a 11 ¼" recess shoe and 10 1/4" hole size, which is the hole size required by the post-expanded pipe (In such case, pilot hole will be drilled and underreamed to 10 1/4"). This system is a top-down expansion, and the liner will shrink at bottom due to expansion. This mean that excess length of the pre-expanded pipe is required to ensure the post expanded length of the liner. This is accounted for in the model by adding length at bottom of the liner to the pre-expanded pipe. It is assumed the liner will shrink according to the expansion ratio of 19.8%. If the liner is to be installed in a well, a rathole must be drilled to accommodate excess liner length. The liner is not cemented hence TOC is at the casing shoe (at 4036 mMD). The liner will clad to the recess shoe by metal to metal seal, which will act as the hanger itself and top seal. The liner hanger length is 7m. The casing and tubing scheme down to the 9 7/8" shoe and the 6 5/8" completion string is as for well J-4. The liner is analyzed for mud weights 1.3sg, 1.1sg, 1.0sg and 0.8sg in five different pressure regimes according to the Garn depletion prediction presented in section 8.8.1.

TABLE 28: LINEXX™ HIGH COLLAPSE PRE EXPANDED NON-CEMENTED STRING SECTION

String section										
OD	Weight	Grade	ID	Yield	Int Drift	Pipe Type	Burst	Collapse	Axial	UTS
(in)	(ppf)	-	(in)	(bar)	(in)	Type	(bar)	(bar)	(daN)	(bar)
8.000	32.460	X-52	7.200	3585.27	7.075	Special	344.737	262.000	297377.4	4550.54

TABLE 29: LINEXX™ HIGH COLLAPSE PRE EXPANDED NON-CEMENTED CASING AND TUBING SCHEME

linEXX™ high collapse non cemented post expanded							
OD (in)	Name	Type	Hole Size (in)	Measured Depths (m)			Mud at shoe (sg)
				Hanger	Shoe	TOC	
30"	Conductor	Casing	36.00	342	429.29	342	1.03
	Surface	Casing	24.00	341.5	1055.46	342	1.30
13 5/8"	Intermediate	Casing	17.50	341	2687	2387	1.53
10 3/4"	Production	Casing	12.25	340.5	4036.7	2940	1.59
8"	Production	Liner	9.75	4029.7	4436.7	4436	1.30 - 0.80
6 5/8"	Production	Liner	8.50	4436	5450	5450	1.30 - 0.80

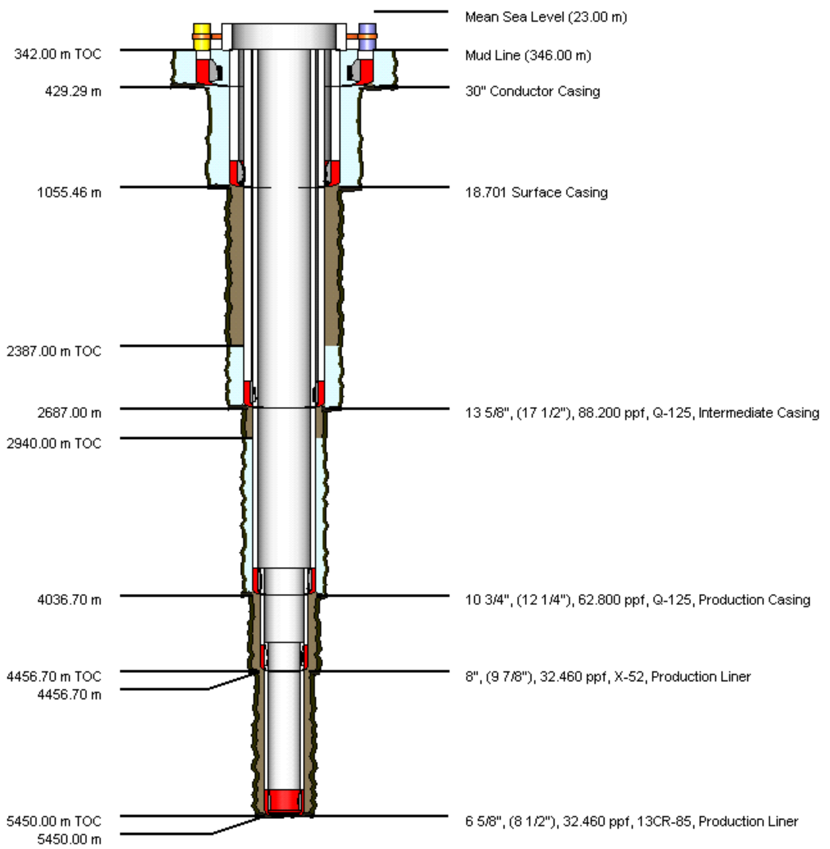


FIGURE 34: LINEXX™ HIGH COLLAPSE NON-CEMENTED PRE EXPANDED WELL SCHEMATIC

9.4.2 Case 8: linEXX™ high collapse non-cemented post expanded

The linEXX™ high collapse non-cemented post expanded liner is modeled as T-95 to simulate the technical specifications by the vendor. The connection type is TenarisHydril 723 LH. The technical data sheet can be found in Appendix 3 and the input data to the StressCheck files are listed below in Table 30 and the casing and tubing scheme in Table 31 and in the well schematic in Figure 35.The liner requires a 9 7/8" base pipe with a 11 ¼" recess shoe and 10 1/4" hole size, which is the hole size required by the post-expanded pipe (In such case, pilot hole will be drilled and underreamed to 10 1/4"). This system is a top-down expansion, and the liner will shrink at bottom due to expansion. This mean that excess length of the pre expanded pipe is required to ensure the post-expanded length of the liner. This is accounted for in the model by adding length at bottom of the liner to the pre-expanded pipe. It is assumed the liner will shrink according to the expansion ratio 19.8 %. If the liner is to be installed in a well, a rat hole must be drilled to accommodate excess liner length. The liner is not cemented; hence TOC is at the previous casing shoe (at 4036 mMD). The liner will clad to the recess shoe by metal to metal seal, which will act as the hanger itself and top seal. The liner hanger length is 7m. The casing and tubing scheme down to the 9 7/8" shoe and the 6 5/8" completion string is as for well J-4. The liner is analyzed for mud weights 1.3sg, 1.1sg, 1.0sg and 0.8sg in five different pressure regimes according to the Garn depletion prediction presented in section 8.8.1.

TABLE 30: LINEXX™ HIGH COLLAPSE POST EXPANDED NON-CEMENTED STRING SECTION

String section										
OD	Weight	Grade	ID	Yield	Int Drift	Pipe Type	Burst	Collapse	Axial	UTS
(in)	(ppf)	-	(in)	(bar)	(in)	Type	(bar)	(bar)	(daN)	(bar)
9.348	32.460	x-60	8.600	4136.86	8.500	Special	390.930	159.200	281413.7	5171.07

TABLE 31: LINEXX™ HIGH COLLAPSE PRE EXPANDED NON-CEMENTED CASING AND TUBING SCHEME

linEXX™ high collapse non cemented post expanded							
OD (in)	Name	Type	Hole Size (in)	Measured Depths (m)			Mud at shoe (sg)
				Hanger	Shoe	TOC	
30"	Conductor	Casing	36.00	342	429.29	342	1.03
	Surface	Casing	24.00	341.5	1055.46	342	1.30
13 5/8"	Intermediate	Casing	17.50	341	2687	2387	1.53
10 3/4"	Production	Casing	12.25	340.5	4036.7	2940	1.59
9.348"	Production	Liner	9.75	4029.7	4436.7	4436	1.30 - 0.80
6 5/8"	Production	Liner	8.50	4436	5450	5450	1.30 - 0.80

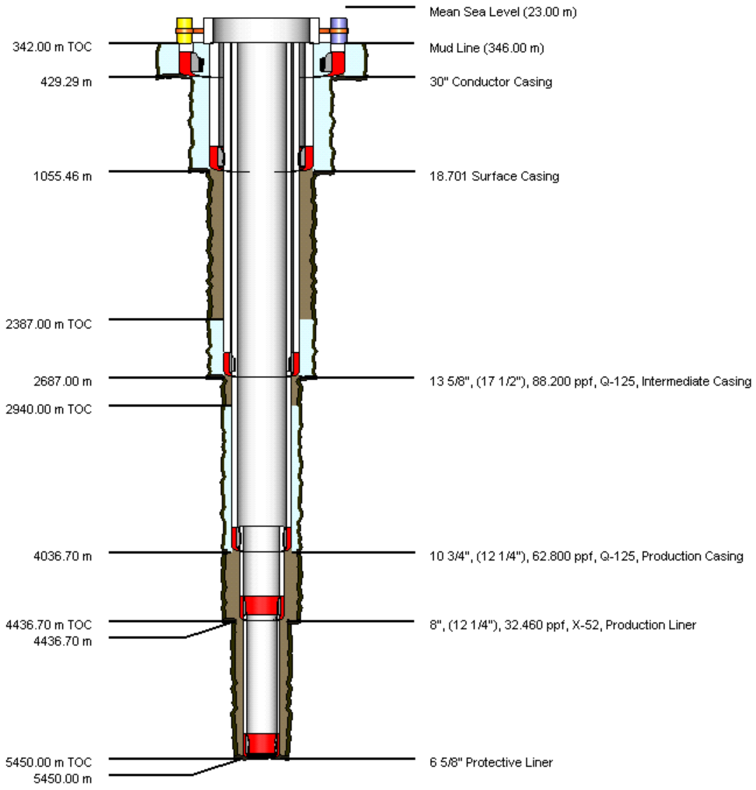


FIGURE 35: LINEXX™ HIGH COLLAPS NON- CEMENTED POST EXPANDED WELL SCHEMATIC

9.5 Summary

Company		Enventure GT	Enventure GT	Enventure GT	Enventure GT	Baker Hughes	Baker Hughes	Baker Hughes	Baker Hughes
liner/system Name	Unit	7.625 x 9 7/8 pre exp SET®	7.625 x 9 7/8 Post exp SET®	8.625 x 10 3/4 Pre exp SET®	8.625 x 10 3/4 Post exp SET®	Pre exp high collapse non cement linEXX™	Post exp high collapse non cement linEXX™	Pre exp high collapse cemented linEXX™	Post exp high collapse cemented linEXX™
prev casing OD	"	9 7/8	9 7/8	10 3/4	10 ¾	10 3/4	10 3/4	11 1/4	11 1/4
prev casing ID	"	8.625	8.625	9.76	9.76	9.35	9.35	9.35	9.35
prev casing drift	"	8.5	8.5	9.625	9.625	9.348	9.348	9.348	9.348
prev casing shoe	mMD	4036.7	4036.7	4036.7	4036.7	4036.7	4036.7	4036.7	4036.7
hole size liner	mMD	9.5	9.5	9.5	9.5	9.875	9.875	10.625	10.625
hanger top	mMD	3936.7	3940.7	3936.7	3940.7	4029.7	4029.7	4029.7	4029.7
hanger bottom	mMD	4036.7	4036.7	4036.7	4036.7	4036.7	4036.7	4036.7	4036.7
liner top	mMD	4036.7	4036.7	4036.7	4036.7	4036.7	4036.7	4036.7	4036.7
liner shoe	mMD	4436.7	4436.7	4436.7	4436.7	4456.7	4436.7	4456.7	4436.7
TOC	mMD	4036.7	4036.7	4036.7	4036.7	4456.7	4436.7	4456.7	4036.7
cement length	mMD	300.7	300.7	300.7	300.7	0	0	0	400
hanger length	m	100	96	100	96	7	7	7	7
liner length (ex. Hanger)	m	400	400	400	400	420	400	420	400
total installed length	m	500	496	500	496	427	500	427	500
liner OD	"	7.625	8.529	8 5/8	9.555	8	9.348	8	9.348
liner ID	"	6.625	7.58	7.625	8.6	7.2	8.6	7.2	8.6
liner Drift	"	6.5	7.504	7.5	8.514	7.075	8.5	7.075	8.5
liner weight	ppf	39	40.51	44	45.93	32.46	33.36	32.46	33.36
liner grade given	-	L-80	NA	L-80	NA	SX50	NA	SX50	NA
liner grade found	-	NA	C-90	NA	C-90	X-52	X-60	X-52	X-60
grade yield	bar	5515.81	6205.28	5515.81	6205.28	3447.37	4136.86	3447.37	4136.86
Yield calculated (based on exp. %)	bar	NA	6310.08664	NA	6221.83368	3585.27	4129.94926	3585.27	4129.94926
standard/special pipe	-	standard	special	standard	Special	special	special	special	special
burst	bar	632.961	525	559.575	471.6	344.737	390.93	344.737	390.93
collpase	bar	607.841	315	479.068	259.9	262	159.2	262	159.2
expansion percantage	%	NA	14.4	NA	12.8	NA	19.8	NA	19.8
shortening	m	NA	4	NA	4	NA	20	NA	20
expanded from top/bottom	-	NA	bottom	NA	Bottom	NA	top	NA	top

10 Analysis results

Detailed analyses results of the different cases are found in this section. For explanation of the different load cases refer to section 8.6. The length and dimensions of the expandables used in StressCheck is presented in section 9. All temperature profiles are set to default in StressCheck.

10.1 StressCheck modeling of expandable liner

Eight files, presented in Figure 36, were set up in StressCheck to model the loads on 7.625 x 9 7/8" SET® , 8.625 x 10 ¾" SET®, high collapse cemented *linEXX*™ and high collapse un-cemented *linEXX*™.

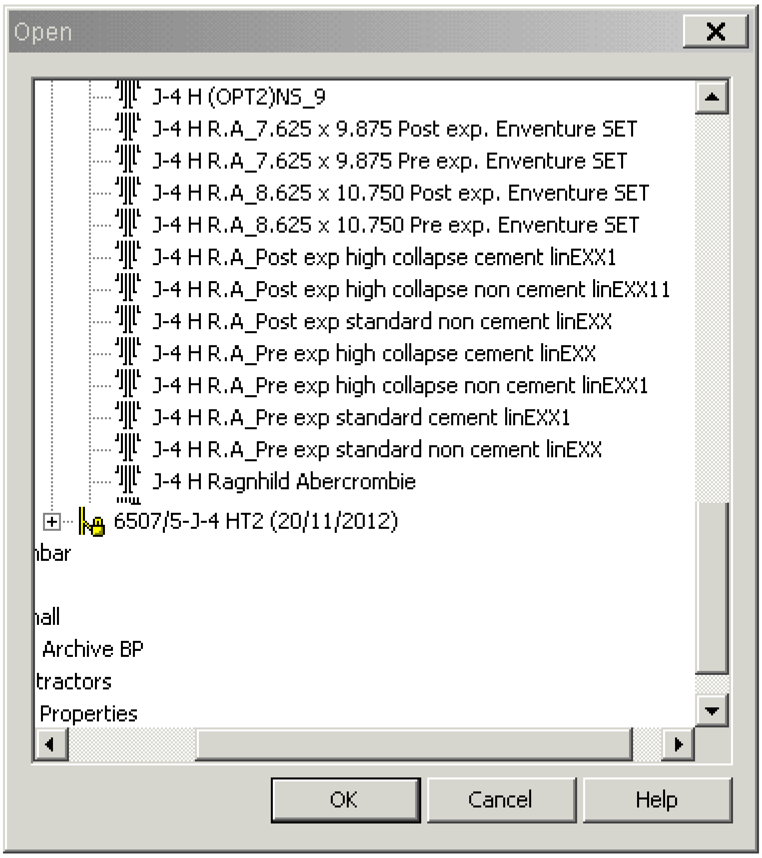


FIGURE 36: STRESSCHECK FILES

10.1.1 Grade sensitivity

To simulate the alteration of yield strength during expansion, different steel grades was used for the pre -and post-expandable when yield strength in StressCheck is fixed to the steel grade. As seen in Figure 37, and as anticipated when chosing the approach, the steel grade can be chosen freely to simulate the required nominal yield strength without compromising the pipe burst and/or collapse strength.

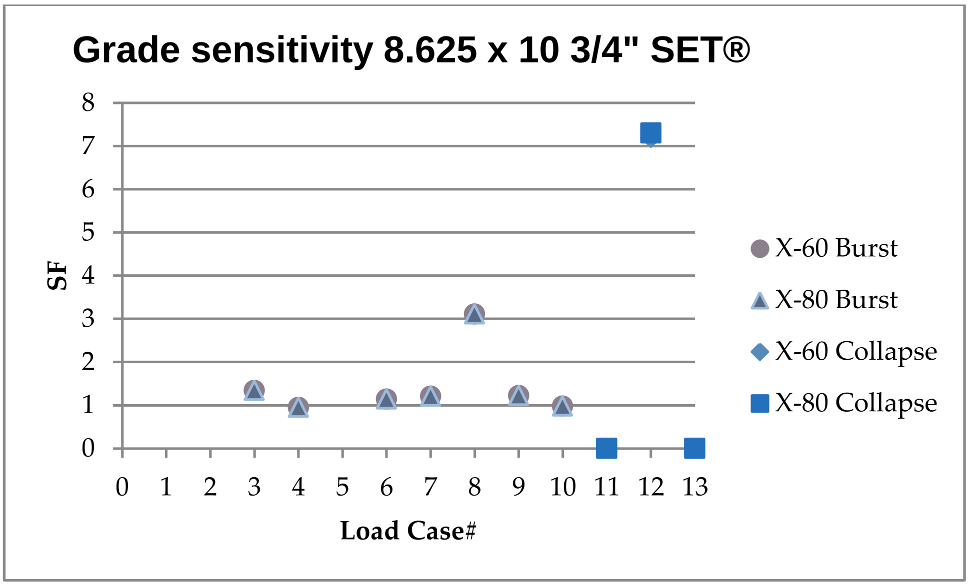


FIGURE 37: GRADE SENSITIVITY 8.625X10 ¾" SET®

10.1.2 Modeling Enventure SET® system

The Bauschinger effect, explained in section 2.1.10 and the expected increase in yield strength in a tensile manner, leads to an increase in burst strength and a reduction in collapse strength during the cold working expansion of the tubular. To model this in StressCheck, the pre -and post-expanded pipe must be modeled as two different pipes.

Enventure GT's 7.625 x 9 7/8" expandable system technical sheet, as given in Appendix 1; presents the SET®-liner pre-expansion properties as standard L-80 pipe. However, by modeling the pre-expanded pipe in such way and according to the dimension in the technical sheet, the resulting burst and collapse strength is 632bar and 607bar respectively. The post expansion value for burst and collapse is given specific on the technical sheet and are 525bar and 315bar respectively. This gives a rather large decrease of 107bar in burst strength, which is not according to theory. The 7.625 x 9 7/8" was however analyzed in StressCheck according to the technical sheet. The analysis result in Figure 38 below show a distinctive higher SF for all the burst load cases for the pre-expanded pipe apposes to the post-expanded pipe. The results are from the undepleted case, using a 1.3sg fluid as mud and displacement fluid. Detailed results and input data is presented in Appendix 4.

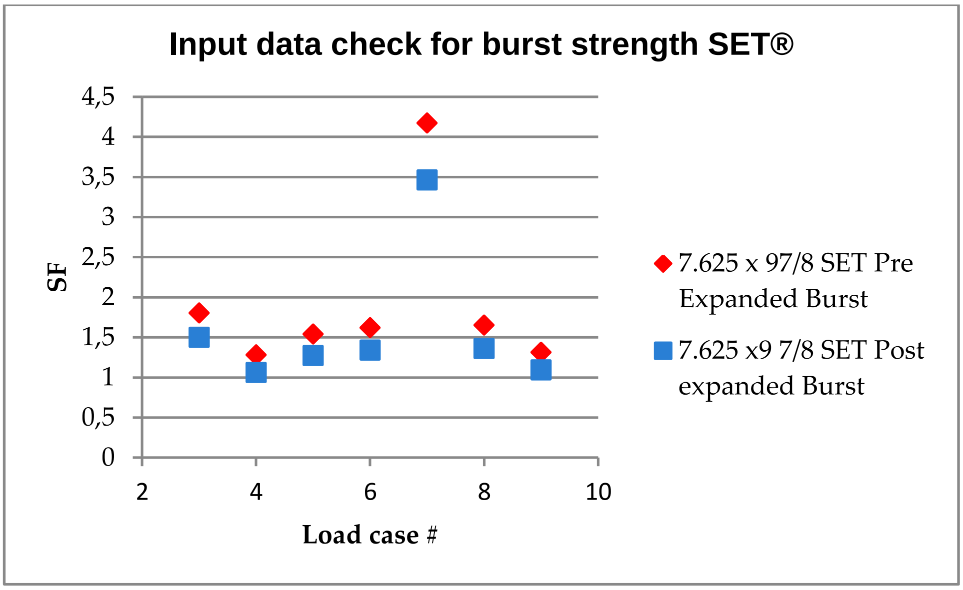


FIGURE 38: INPUT DATA CHECK FOR BURST CASES SET®

On the contrary, when modeling linEXX™, both pre -and post-expansion properties are given specific on the technical sheet, as presented in Appendix 3, where the burst strength is 345bar and 391bar respectively for the pre- and post-expanded pipe. This is a 46bar increase in burst strength which is more according to theory. The result of the linEXX™ analysis for burst loads are presented in Figure 39 below and show a slightly increase in SF for burst loads after expansion. This is exactly opposite the SET® liner. The results are from the undepleted case, using a 1.3sg fluid as mud and displacement fluid. Detailed results and input data is presented in Appendix 6.

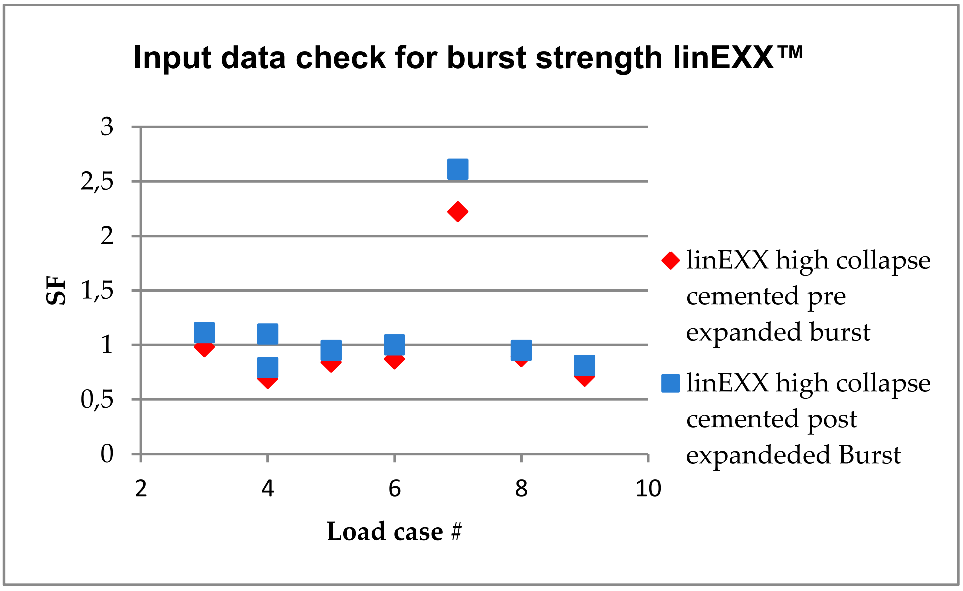


FIGURE 39: INPUT DATA CHECK FOR BURST CASES LINEXX

10.1.3 Mud weight

7.625 x 9 7/8” SET® liner was analysed for 4000 psi depletion with 0.8sg and 1.0 sg mud. The results, presented below in Figure 40 show higher SF for lower mud weights.

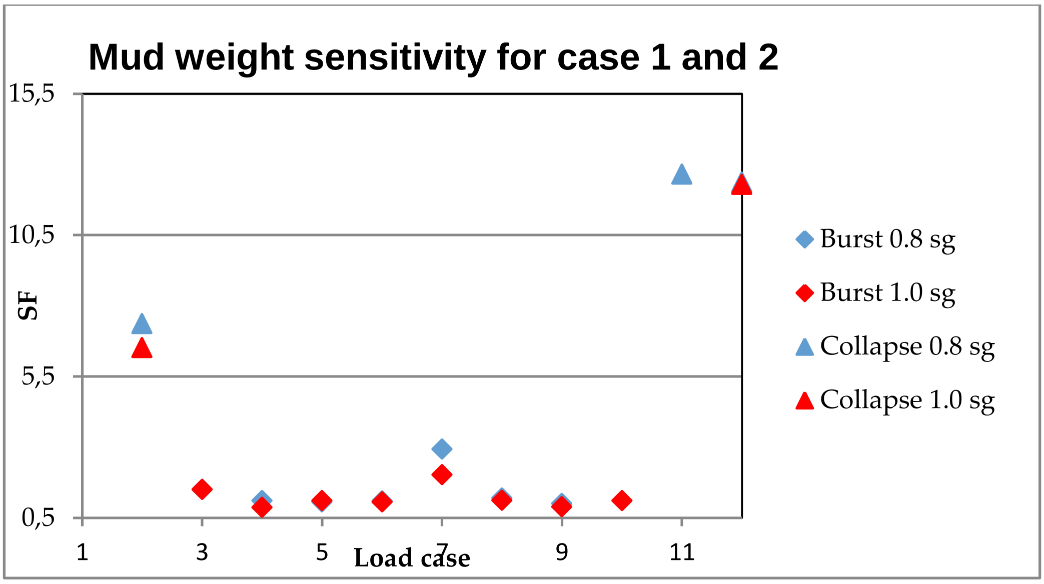


FIGURE 40: MUD WEIGHT SENSITIVITY CASE 1 AND CASE 2

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10.2 7.625 x 9 7/8” Enventure GT SET® liner

In Figure 14, the SF for almost all burst loads decrease when the Garn pressure decreases. This is not obvious, because even if the pore pressure decreases, the mud weight also decreases. The results however show that the liner’s SF decreases for burst resistance during depletion.

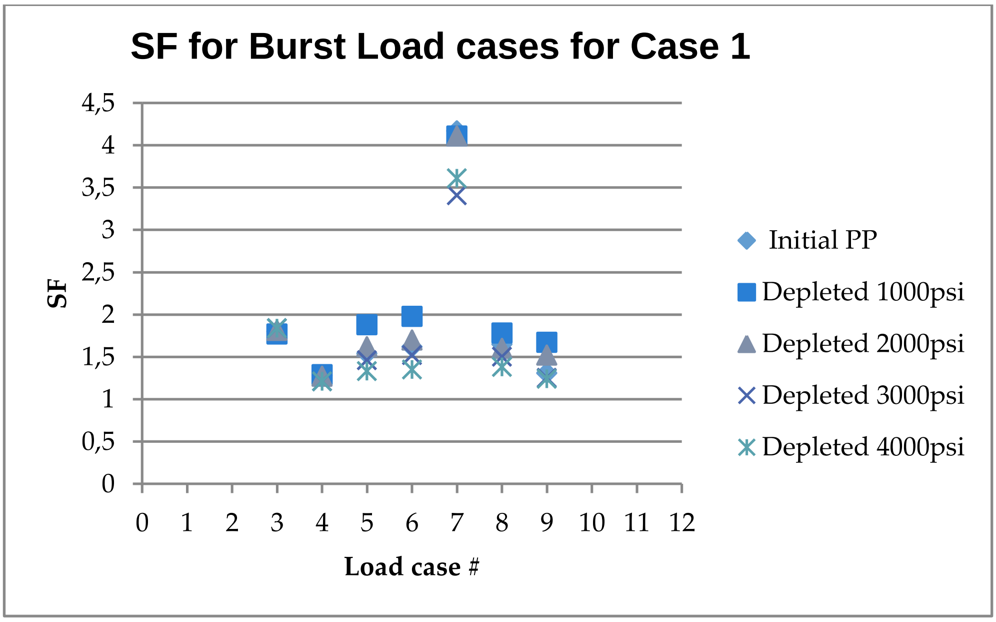

FIGURE 41: SF FOR BURST LOADS CASE 1

The hypothesis was that the liner would be more robust against collapse loads as the pressure outside the liner decreases. In Figure 42, the SF for almost all collapse loads increase when the Garn pressure decreases. This results was neither obvious because the mud weigh, and thus the internal pressure of the liner also decreased. The results confirm the hypothesis and indicate that expandables are suited for depleted zones.

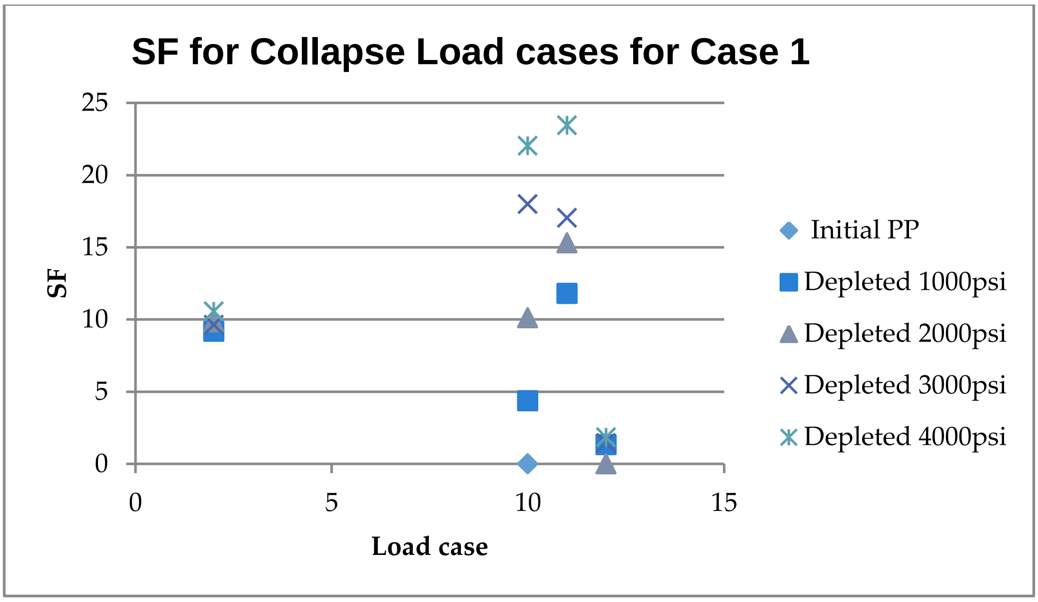

FIGURE 42: SF FOR COLLAPSE LOADS FOR CASE 1

Results presented so far are for the pre-expanded version of the pipe only. By looking at the exactly same load cases for the post-expanded pipe, the SF is distinctive lower. Figure 43 shows the SF for both pipes. It is hence very important to identify which loads are applicable for the pre-expanded pipe and which are applicable for the post-expanded pipe to gain a realistic image of the loading of the liner.

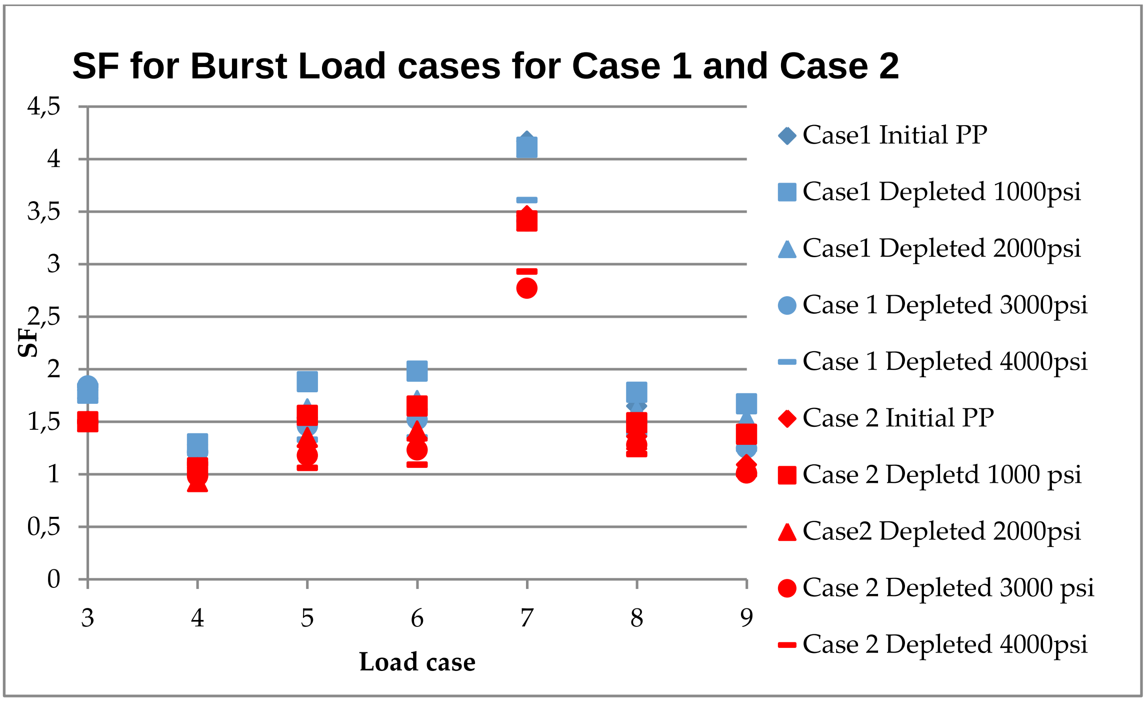

FIGURE 43: SF FOR BURST LOADS FOR CASE 1 AND CASE 2

By examining both pre and post expanded liner for collapse loads, the results, presented in Figure 44, show the same trend, where the exactly same load cases the SF is distinctive lower for the post-expanded pipe.

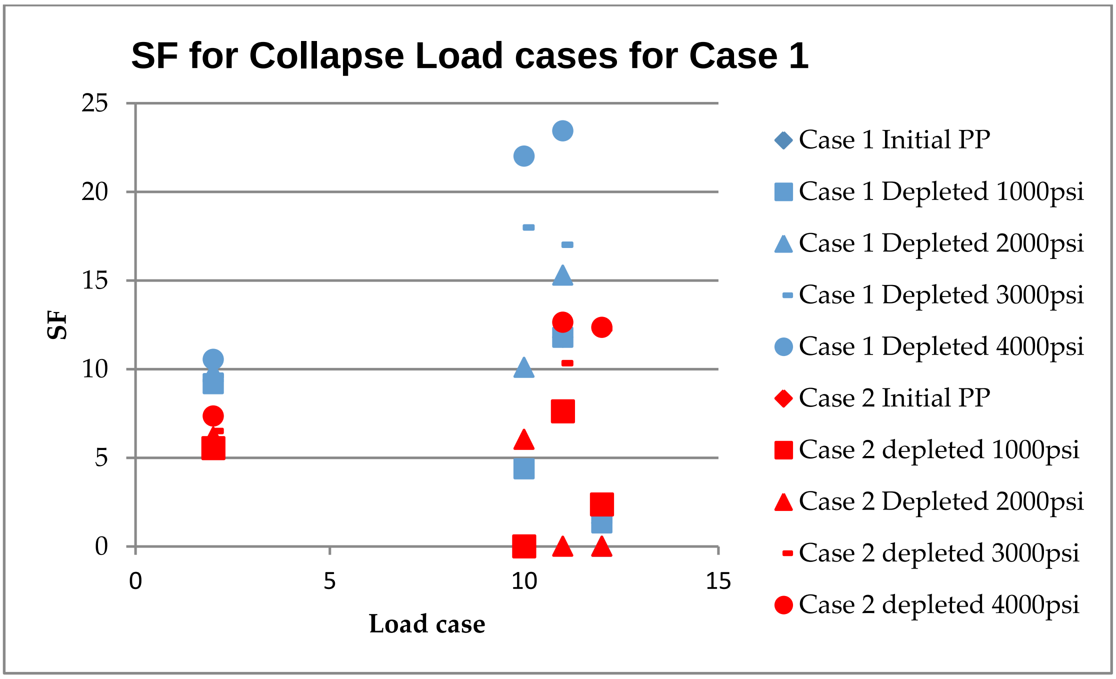

FIGURE 44: SF FOR COLLPASE LOADS FOR CASE 1 AND CASE 2

The above results shows that the loading capacity for the post-expansion is reduced in relation to the pre-expanded pipe which tell us that it is important to identify the applicable loads for each "pipe". The combined results for the 7.625 x 9 7/8" SET® liner is presented in

Figure 45 below. The input data and results are presented in detail in Appendix 4 where also the load cases and pressure regimes are explained. The results assume the liner is cemented prior expansion.

The lowest SF for the burst cases is 0.93 for pressure test with 0.7sg pore pressure as external pressure and 345bar surface test pressure and a fluid column of 1.1sg OBM in the well as internal pressure. By decreasing the surface pressure to 225bar, the SF is 1.10, which is the minimum SF for burst loads. In Table 14, the minimum surface test pressure for 1.1sg mw is 347bar included 10% SF and 316 bar without SF. Hence, the 7.625 X 9 7/8” SET® liner does not have the required burst resistance to endure all load cases.

The lowest SF for the collapse cases is 2.35, whereas the minimum required SF for collapse loads are 1.0. Hence the 7.625 X 9 7/8” SET® liner has the required collapse resistance to endure all possible collapse loads.

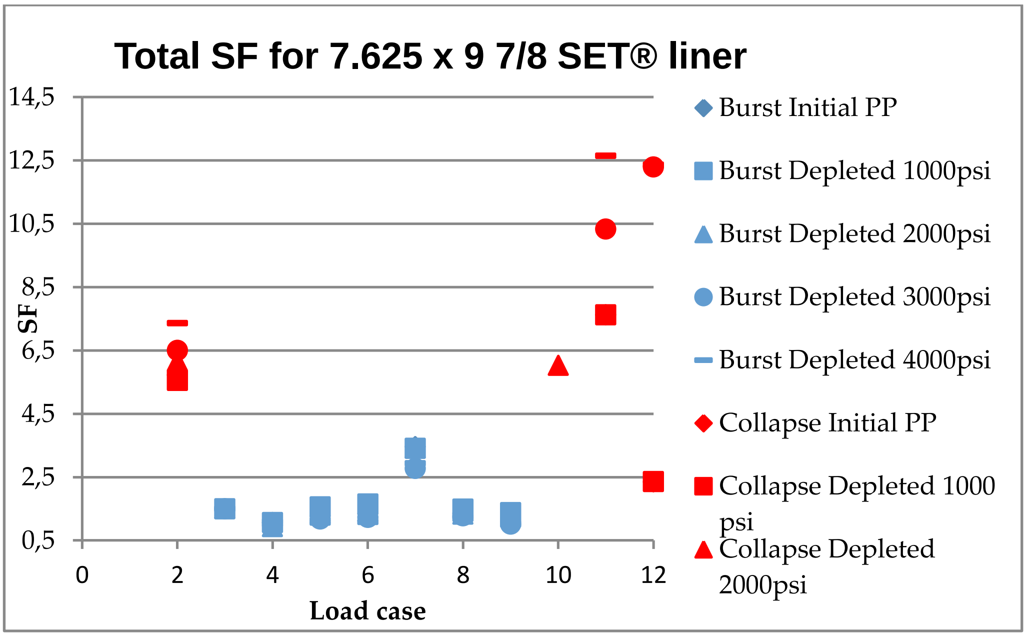

FIGURE 45: TOTAL SF FOR 7.624 X 9 7/8 SET® LINER

10.3 8.625 x 10 ¾” Enventure GT SET® liner

The combined results for the 8.625 x 10 3/4” SET® liner is presented in Figure 46 below. The input data and results are presented in detail in Appendix 5, where also the load cases and pressure regimes are explained. The results assume the liner is cemented prior expansion.

The lowest SF for the burst cases is 0.88 for pressure test with 0.5sg pore pressure as external pressure and 345bar surface test pressure and a fluid column of 1.0sg OBM in the well as internal pressure. The same result is for the 0.3 sg pore pressure with 0.8 sg case. By decreasing the surface pressure to 245bar, the SF is 1.10, which is the minimum SF for burst loads. In Table 14, the minimum surface test pressure for 1.1sg mw is 352 bar and 360 bar erespectively for the two cases included 10% SF. Hence, the 8.625 X 10 3 /4” SET® liner does not have the required burst resistance to endure all load cases.
The results applied is assuming that the liner is pressure tested after expansion.

The lowest SF for the collapse cases is 2.02 whereas the minimum required SF for collapse loads are 1.0. Hence the 8.625 X 10 3/4" SET® liner has the required collapse resistance to endure all possible collapse loads.

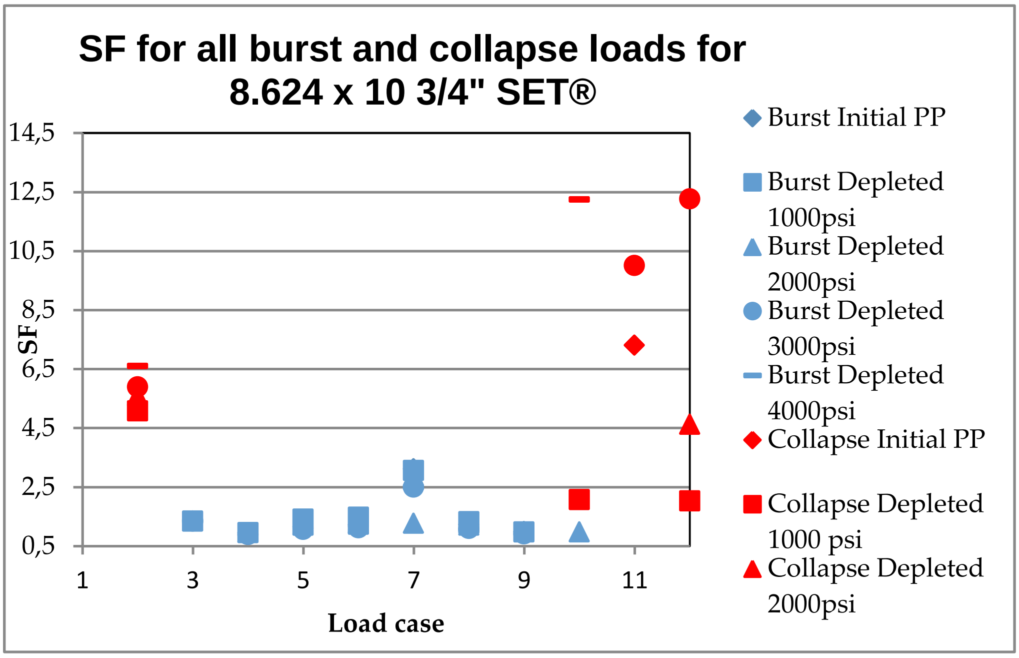

FIGURE 46: TOTAL SF FOR THE 8.625 X 10 ¾ SET® LINER

10.4 7.625 x 9 7/8 vs 8.625 x 10 ¾ SET®

Figure 47 below show the results from comparing 7.625 SET® with 8.625 SET® by keeping all the variable input data constant except liner specifics. For the burst loads there is almost no difference in SF, but for collapse, the 8.625 have mostly a higher SF. The trends indicate that the 8.625 liner is a stronger pipe.

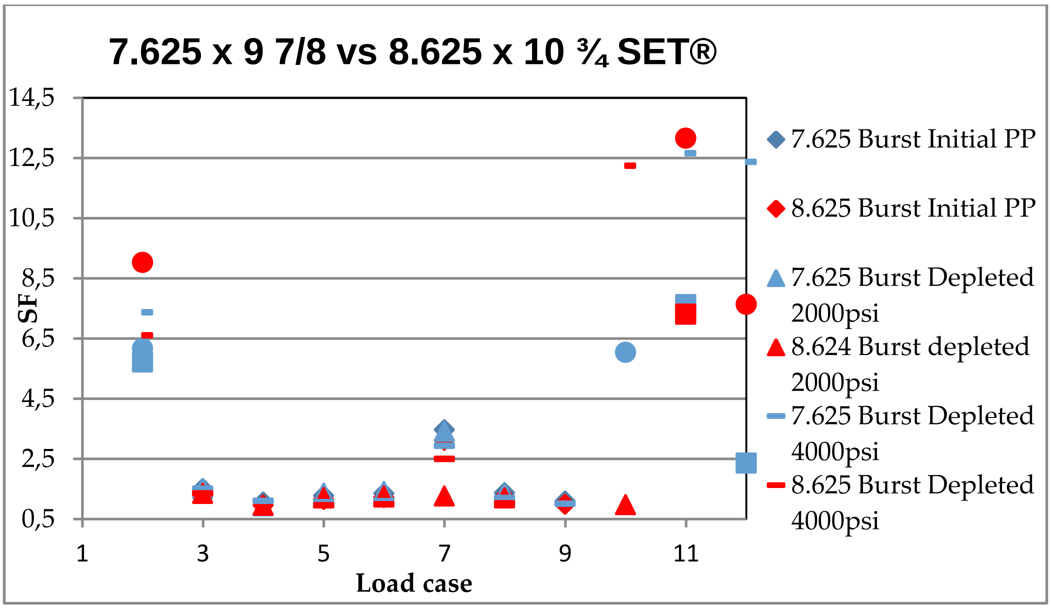

FIGURE 47: 7.625 VS 8.625 SET® LINER

10.5 Baker Hughes linEXX™ high collapse cemented liner

The combined results for the hig collapse cemented linEXX™ is presented in Figure 48 below. The input data and results are presented in detail in Appendix 6, where also the load cases and pressure regimes are explained. The results assume the liner is cemented prior expansion.

The lowest SF for the burst cases is 0.73 for pressure test with 0.5sg pore pressure as external pressure and 345bar surface test pressure and a fluid column of 1.0sg OBM in the well as internal pressure. The same result is for the 0.3 sg pore pressure with 0.8 sg case. By decreasing the surface pressure to 172 bar, the SF is 1.10, which is the minimum SF for burst loads. In Table 14, the minimum surface test pressure for 1.1sg mw is 352bar and 360bar for 0.8 sg mud, included 10% SF. In addition SF lower that minimum SF is found for all burst cases with different mud weights and pressures. Hence, high collapse cemented linEXX™ liner does not have the required burst resistance to endure all load cases.

The lowest SF for the collapse cases is 1.32 whereas the minimum required SF for collapse loads are 1.0. Hence the high collapse cemented linEXX™ liner has the required collapse resistance to endure all possible collapse loads.

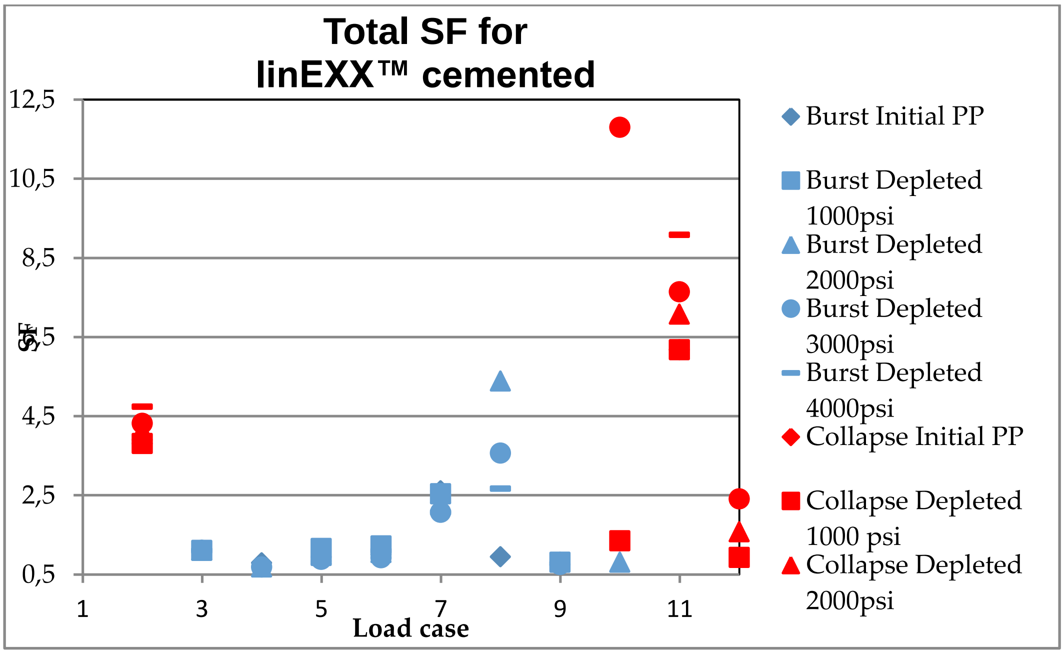

FIGURE 48: TOTAL SF FOR CEMENTED LINEXX™

10.6 Baker Hughes linEXX™ high collapse non-cemented liner

The combined results for the hig collapse cemented linEXX™ is presented in Figure 49 below. The input data and results are presented in detail in Appendix 7, where also the load cases and pressure regimes are explained. The results assume the liner is cemented prior expansion.

The lowest SF for the burst cases is 0.66 for injection down casing with 0.5sg pore pressure as external pressure and 345bar surface test pressure and a fluid column of 1.0sg OBM in the well as internal pressure. By decreasing the surface injection pressure to 140bar, the SF is 1.10, which is the minimum SF for burst loads. The required injection pressure has not been calculated. In addition SF lower that minimum SF is found for all burst cases with different mud weights and pressures. Hence, high collapse non-cemented linEXX™ liner does not have the required burst resistance to endure all load cases.

The lowest SF for the collapse cases is 1.35 whereas the minimum required SF for collapse loads are 1.0. Hence the high collapse cemented linEXX™ liner has the required collapse resistance to endure all possible collapse loads.

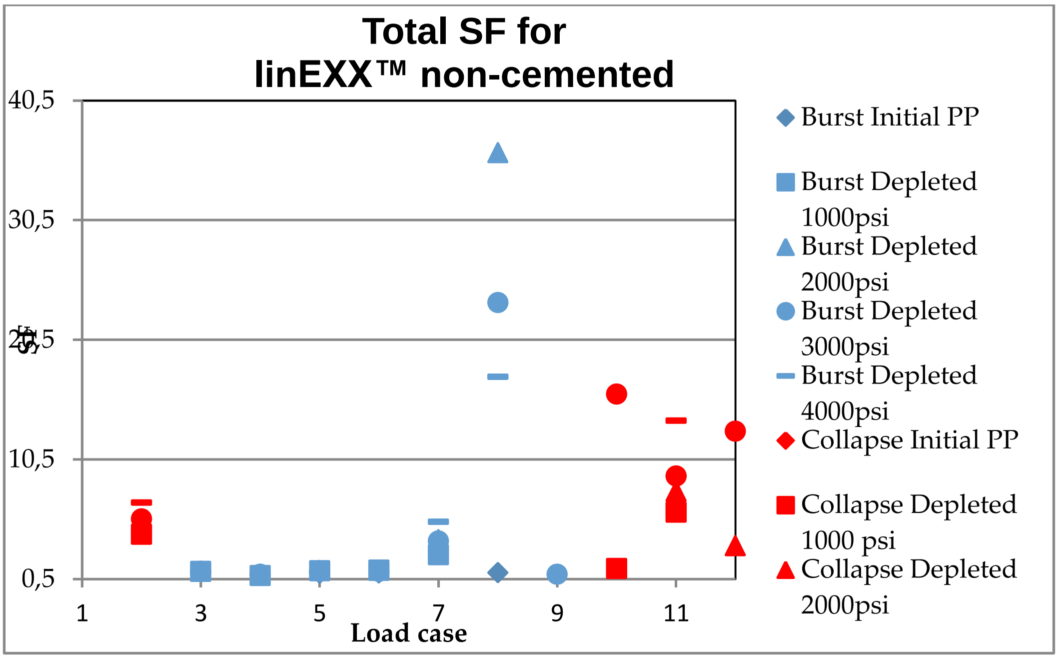

FIGURE 49: TOTAL SF FOR NON-CEMENTED LINEXX™

10.7 Cemented vs non-cemented linEXX™

Below is shown the results from comparing cemented and non-cemented linEXX™ by keeping all the variable input data constant except liner specifics. For the burst loads there is almost no difference in SF, but for collapse, the non-cemented have mostly a higher SF. The trends indicate thet the for a depleted reservoir where a cement column as external pressue exceeds the formation pressure, a non-cemented liner would be more robust against collapse loads.

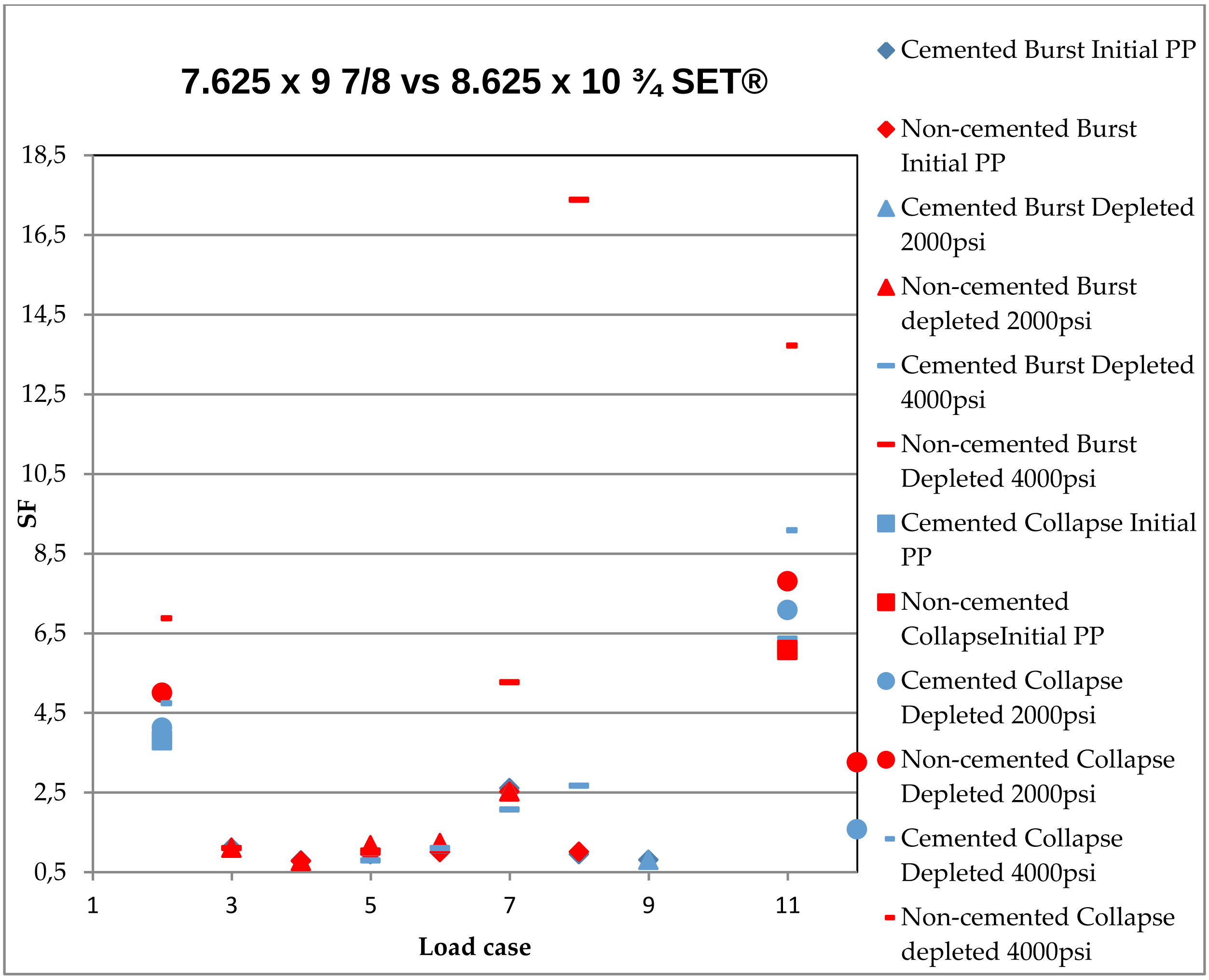

FIGURE 50: CEMENTED VS NON-CEMENTED LINEXX™

10.8 SET® vs linEXX™

Figure 51 below show the results from ultimately comparing SET® to linEXX™.All variable input data are kept constant except liner specifics. For the burst loads there is almost no difference in SF, but for collapse, linEXX™ have mostly a higher SF. The trends indicate thet the linEXX™ liner is a more suitable pipe for the applicable loads.

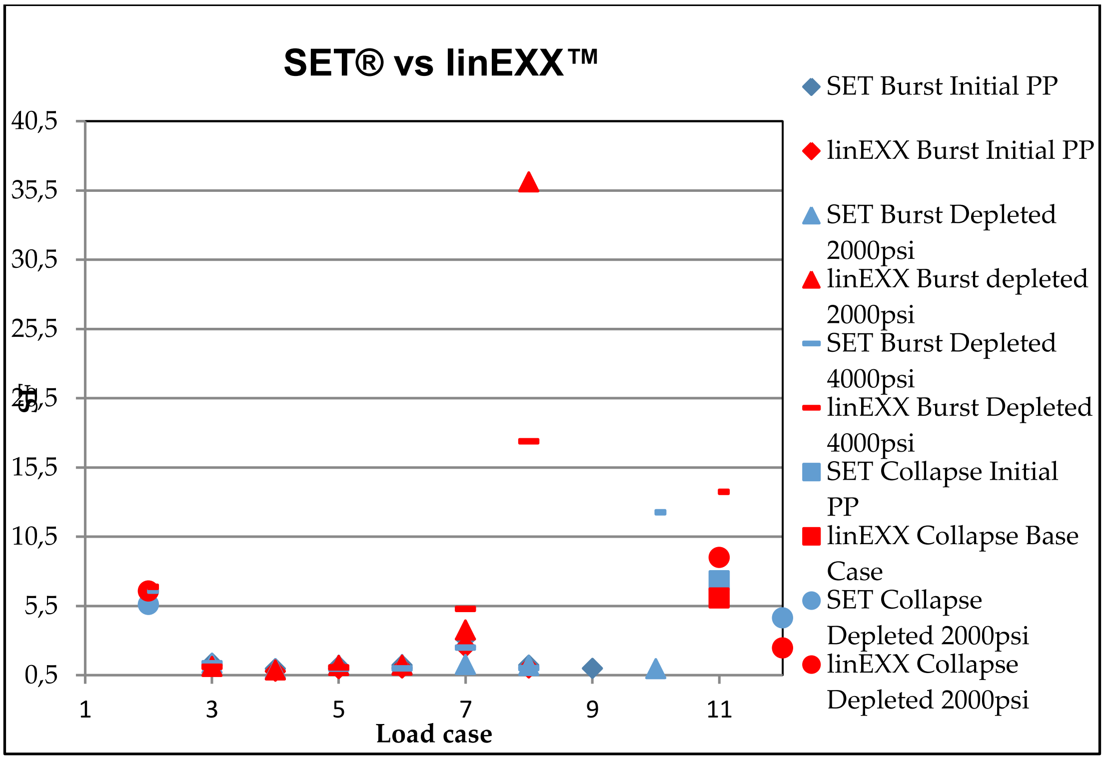

FIGURE 51: SET® VS LINEXX™

11 Discussion

11.1 Expandables for depleting reservoirs

Historically, expandables fail in collapse resistance. For Garn, which is a depleting reservoir, however, it is the burst rating that is limiting. Especially for the load cases including high test and injection pressures where the high internal pressure from the mud weight and the applied surface pressure are to high compared to the low external reservoir pressure. When it is the internal pressure that is the pressure that can be controlled, e.g. mud weights can be tailor-made to avoid exceeding the burts limits. Also for an application where the liner shall only stabilize the bore while drilling the next section, high test pressure is not necessarily a show stopper, but if the expandable is to be installed as a production liner, actuall test and injection pressures must be considered. Expandables are hence a good solution to isolate depleting reservoirs.

11.2 Expandable for Skarv casing design

The available systems that will give an 8 ½" hole section through Tilje is the 8.625 x 10 3/4" SET® option and the linEXX™ option. To be able to utilize the SET®, a 10 ¾" base casing is required, as the name implies, and if the current design of 9 7/8" base case is to be kept, linEXX™ is the only solution. It should be noted that Weatherford's MetalSkin have not been evaluated as an option. There is however no indications that the 10 ¾ "cannot be run all down to top Garn, but there can be some weight limitations on the rig. If linEXX™ is to be run, a recess shoe on the previous casing is required. This is designed according to the base pipe's connection OD. The linEXX™ however is a top-down expansion system that shrinks the liner at bottom during the expansion. Excessive liner length must therefore be installed. This can be a problem when the shale layer above where the shoe is to be set is not necessarily long enough.

11.3 SET® vs. linEXX™

LinEXX™ have lower burst and collapse rating than the SET® liner and SET® becomes the obvious choice regarding strength as a first approach. When comparing the strongest SET® with the strongest linEXX™ in StressCheck however, linEXX™ has slightly higher SF for collapse whereas there is no obvious trend when it comes to burst.

Installation wise, linEXX™ is expanded top-down to allow for step wise expansion if e.g. a wait on weather situation occur, which is highly relevant for Skarv subsea wells. LinEXX™ is also cemented pre-expansion which makes it somehow retrievable if expansion fails. However have post-expansion cementing proved to be worst case for the liner regarding cementing. Another advantage about the LinEXX™ is that the system leaves no tools in the well and all equipment is standard sizes. The latter does not apply to all expandables and a non API ID can drive up well costs due to the need for special or even tailor made subsequent drilling equipment. The challenge with linEXX™ is that the top-down expansion shrinks the liner at bottom, meaning excessive liner must be installed to ensure the required post-expanded length. A rathole must also be drilled. When drilling with a potential low mud weight in Garn and Ile it is not wanted to drill into Tilje, but to set the shoe in the shale above. Hence the shale above Tilje must be long enough for a rathole section.

SET® is a bottom-up expansion meaning there is no shrinkage at bottom. The system however leaves the expansion launcher downhole to be drilled out. The launcher have proven to be sometimes difficult to drill out and can require underreaming. SET® liners are cemented pre-expansion meaning the solution requires full expansion directly following the cementing. Otherwise the cement can be set before the liner is expanded. A good weather window and cement with long settling time is hence required to ensure a full expansion before cement settles.

The SET® reduced the ID while linEXX™ leave a monobore. The linEXX™ needs to be planned in due to the recess shoe, while SET® can more easily be a contingency string. Overall there is small differences regarding strength between the liners, the biggest difference is the installation and drilling requirements.

11.4 Contingency vs. Planned

Expandables are often used as contingency strings, but as for all operations it is beneficial to incorporate the installation in the early planning. One of the benefits for an expandable is that controllable variables, like the mud weight, can be tailor-made to suite the expandables burst rating. If linEXX™ is to be installed, planning is required considering the recess shoe. It can also be argued that pre-planning engineering can be cost efficient compared to problemsolving during operation.

11.5 Applicable loads

Both the SET® and linEXX™ liner's burst ratings were exceeded in the load analysis. Even if the load analysis performed for this thesis was somehow comprehensive, assessing the liner for the load cases and pressures that the expandable will actual see in a realistic case will be beneficial. Expandables will probably be on the limit of what are the requirements and it is most likely that an expandable will be a better fit if assessed thoroughly regarding relevant loads.

11.6 Connections

The connections are the expandable's Achilles's heal. As per today, no available expandable tubulars have gas tight connections. Gas tight connections are however a requirement for a production casing or liner. DeLange et. Al. 2011 presents assessment of a special cone that expands the tubular with less stress on the connections. If an expandable liner shall be considered as an option, the requirements for the liner's connections must be established. Finding a solution for the lack of gas thightness however can be time consuming.

11.7 Barriere requirements

There are requirements regarding control of fluid flow between formations. Is the expandable good enough to ensure no flow from Tilje into Garn without gas tight connections? If the production packer is set above the expandable shoe, what is the barrier requirements then? During the work on this thesis these questions could not be answered as it requires assessment of formations and the completion design which is time consuming. It should however be a part of future discussions.

11.8 Production liner requirements

Does the expandable need to have the same requirements as the 9 7/8" production casing? The vendors advise to set the production packer in the 9 7/8", what loads are apllicable for the expandable then? The 9 7/8" liner shoe and production packer set in the 9 7/8 casing will then be the main well barrier. To serve as a production liner, there are requirements that the liner shall act as a barrier against influx of oil into uncontrolled reservoirs. The common practice in the industry is to straddle the expandable to mitigate the problem. That cannot be done on Skarv as it will reduce the ID and the expandable becomes redundant.

11.9 StressCheck

To get a complete load assessment of the expandable the user must be sure of the post and pre properties and preferably analyse the liner in two cases as pre- and post-expanded pipe separately. Sensitivity analysis and results in a range is preferable to catch any uncertainties.

Referring to the technical input data confusion about the SET® expandables, it is crucial to have knowledge of the expected pipe property changes that occur during the expansion process and make sure the correct and believable/tested properties are supplied by the vendor if the pipe is to be modeled and analyzed in StressCheck. Some load case analysis and knowledge of the mechanical properties of steel is preferable for the engineer performing the analysis. In addition, working with two files can make twice the trouble and one must be aware of what the software does, what is put into it and what the purpose of the results are.

The expandables are sensitive to mud weight changes and it must be ensured that the liner is load case analyzed for the real mud weights to be used and in a +/- range to incorporate the sensitivity.

11.10 Risk, advantages and challenges

The alternative to an expandable liner with a 8 ½" ID and an 6 5/8" completion string is a 7" liner and a 4 ½" completion string. This is a slim hole solution, leaving a narrow annulus in the reservoir section wich will increase the ECD when Gravel packing. The potential result is that it is not possible to gravel pack the whole reservoir section which can lead to hole collapse. The Skarv team's assessement is that installing an expandable have no larger risk than a slim hole solution for the overall well sucess. The highest risk identified is that the expandable solution might be a time trap regarding solving issues like the requirement for gas tight connections. Installing an expandable might be the only solution to the risk of not being able to drill and complete the wells

Advantages by installing an expandable liner:

- No slim hole drilling, the hole is more drillable
- No diameter reduction for the lower completion. ECD can be maintained and a higher success rate for Gravel Pack (GP), the overall GP operation is easier
- Potential contingency string in reservoir

Challenges by installing an expandable liner:

- An expandable requires a more time consuming load assessment than conventionall liner
- Not gas tight connections
- Design can be a potential time trap
- Time consuming to plan

11.11 Cost

Special tubular is expensive compared to standard pipe. Expandables requires perfect circularity to ensure symmetrical expansion and a special metallurgy to ensure the post-expansion properties. The overall understanding and the initiative for this thesis is however that even if expandables are expensive and it is a new technology it might be the only economically feasible method to preserve the required ID and hence the best solution for Skarv. Reservoir and production requires a specified pay zone length and Tilje to be isolated from Garn and Ile to control the fluid flow. Completion team requires a minimum API drift of 8 ½" to ensure the whole reservoir section is Gravel Packed. Rock mechanics require gravel pack to mitigate hole collapse. Drilling engineers have weight restrictions to account for.

No cost assessment have been performed for Skarv but analogues can be drawn to other fields. In the Kupal oilfield in Iran, an unexcepcted thief zone was acountered resulting in the need of an additional string. A traditional liner would decrease the hole size and caused problems such as lower reservoir production rate and ID resrictions for measuring tools. The paper includes cost evaluation for comparison of two well, one with a 7" liner and one with an expandable liner. The results are presented in a table in Figure 52. The evaluation show a cost reduction in installing an expandable compared to the 7" liner.

Table 3: Comparison in cost between Kl-29 and KL-41

Name	Bit	Mud	7" Liner Run	5" Liner Run	EOL Run	Cement	Rig Cost	Total
KL-29	$64,830	$72000	$48220	$21760		$1250	$1,541,000	$ 1,749,060
KL-41	$59,356	$88000	$52000		$311602	$600	$1,173,000	$1,684,558

FIGURE 52: COMPARISON IN COST BETWEEN KL-29 AND KL-41IN THE KUPAL FIELD

12 Conclusion and recommendation

- Expandables are a good solution for depleted reservoirs
- Both SET® and linEXX™ are potential solutions for Skarv casing design
- linEXX™ requires pre planning due to installation of an recess shoe on the previous casing
- Both solutions have lowest SF for burst loads. Not all loads can be endured with the input data presented in this thesis. However, the liners show large sensistivity in e.g.mud weights and in collaboration with vendors, most likely a solution that meet the requirements can be achieved
- The alternative to expandable for Skarv is slim hole drilling and completion which have a high risk for an uncomplete gravel pack in the reservoir with potential hole collaps as a result
- Expandables are expensive but so are re-design of completion and casing design which is the alternative
- The limitations are per today that the connection is not gas tight which is a requirement for a production casing to ensure control of fluid flow between reservoirs
- The cost difference between a slimhole design and an expandable design can be the the time that could be needed to spend designing around the lack of gas tight connections
- Load analysis in StressCheck is not straight forward and extra care must be taken to ensure the correct properties are input regarding each load case. Understanding of the pre- and post-expanded properties and StressCheck knowledge is preferable to gain a reliable result.

13 Future work

- Investigation and discussion with vendors about development of better connections could make expandables a preferred solution for isolating depleted reservoirs.
- Establish requirements regarding sealing and barriers.
- Analyze the liners for the actual pressures and mud weights for each well

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Abbreviation

ABL	Alternative Borehole Lining
API	American Petroleum Institute
BHP	Bottom Hole Pressure
BOD	Basis Of Design
BOP	Blow Out Preventer
BPD	Barrels Pr Day
DHPG	Down Hole Pressure and temperature Gauges
ECD	Equivalent Circulating Density
ELH	Expandable Liner Hanger
EMW	Equivalent Mud Weight
EODL	Expandable Cased hole Liner
EQ	Equation
EST	Expandable Slotted Tubular
FG	Fracture Gradient
FIT	Formation Integrity test
Fm	Formation
FOC	FO Cementer
FPSO	Floating Production Storage and Offloading unit
GP	Group Practice
GR	Gamma Ray
H2S	Hydrogen Sulfide gas
HC	Hydrocarbon
HP/HT	High Pressure High Temperature
ID	Inner Diameter
LOT	Leak Off Test
MCL	Metalskin Cased hole Liner
MD	Measured Depth
MEWHP	Maximum Expected Well Head Pressure
MW	Mud Weight
MWW	Mud Weight Window
NA	Not Applicable
NORSOK	Norsk sokkels konkuranseposisjon
NPT	Non Productive Time
OBM	Oil Based mud
OCTG	Oil Country Tubular Goods
OD	Outer Diameter
OHGP	Open Hole Gravel Pack
OHL	Open Hole Liner
OTC	Offshore Technology Conference
P&A	Plug and Abandonment
PDO	Plan for Operation and Development
PL	Production License
PLT	Production Logging Tool
PP	Pore Pressure
QA	Quality Assurance
QC	Quality Check
RKB	Rotary Kelly Bushing
ROP	Rate of Penetration
SET	Solid Expandable Tubular
SF	Safety Factor
SITP	Shut in Tubing Pressure
SPE	Society of Petroleum Engineers

TD	Target Depth
TOC	Top Of Cement
TRSCSSV	Tubing Retrievable Surface Controlled Subsurface Safety Valve
TVD	True Vertical Depth
USM	Uniaxial Strain Model
WH	Well Head
WT	Wall Thickness
XLOT	Extended Leak Off Test

List of symbols

τ_{xy} = Shear stress related normal to the x-axis and a force in y-direction

τ_{xz} = Shear stress related normal to the x-axis and a force in z-direction

τ_{yx} = Shear stress related normal to the y-axis and a force in x-direction

τ_{yz} = Shear stress related normal to the y-axis and a force in z-direction

τ_{zx} = Shear stress related normal to the z-axis and a force in x-direction

τ_{zy} = Shear stress related normal to the z-axis and a force in y-direction

$P_{collpase}$ = Collapse pressure

P_{surf} = Surface pressure

Z_{FL} = Height from fluid level to surface

Z_{TOC} = Height from top of cement to surface

ρ_{Cmt} = Density of cement

$\rho_{displacement\ fluid}$ = Density of displacement fluid

ρ_i = Internal density

ρ_{MWi} = Density of internal mud weight

F_N = Normal Force

F_P = Parallel Force

P = Pressure

P_0 = Pore pressure

P_W = Well pressure

P_w^{frac} = Well pressure that will fracture the formation

R_W = Well radius

T_o = Tensile strength

V_b = Bulk volume

V_m = Matrix volume

V_p = Pore volume

f_{umn} = The specified minimum tensile strength

k_a = Is the burst strength factor

k_{dr} = Correction factor based on pipe deformation and material strain hardening

k_{wall} = Factor to account for the specified manufacturing tolerance of the pipe wall;

n = Dimensionless hardening index

p_{fn} = Normal pore pressure

p_{iR} = Internal pressure at ductile rupture of an end-capped pipe;

t = The specified pipe wall thickness

$Depth_{TOC}$ = Vertical depth in rock down to top of cement

P_{TOC} = Pressure at top of cement

P_{burst} = Burst load

P_i = Internal pressure

P_o = External pressure

ε = Strain

ε_x = Elongating strain, strain in x-direction

ε_x = Lateral strain, strain in y-direction

ε_x = Lateral strain, strain in z-direction

ν = Poisson's ratio

ν_{fr} = Poisson's ratio

ρ_f = Fluid density

σ' = Effective stress

σ'_h = Effective horizontal stress

σ_h = Horizontal stress in x-direction

σ_H = Horizontal stress in y-direction

σ_x = Stress in x direction

σ_y = Stress in y direction

ρ_{MW} = Mud weight density

ρ_{water} = Density of water

$SITP$ = Shut in tubing pressure

A = Area

D = Diameter

E = Young's modulus, E-modulus

F = Force

FG = Fracture Gradient

G = Shear modulus

ID = Inner Diameter

K = Ratio between effective horizontal- and vertical stress

OD = Outer Diameter

g = Gravity

sg = Specific gravity

z = Height

$MEWHP$ = Maximum expected wellhead pressure

TVD = True vertical depth

UCS = UnConfined Strain

β = Failure angle

λ = Elastic moduli

ρ = Density

σ = Stress

φ = Porosity

Appendices

Appendix 1: Enventure GT 7.625 x 9 7/8” SET® technical sheet
Appendix 2: Enventure GT 8.625 x 10 3/4” SET® technical sheet
Appendix 3: Baker Hughes linEXX™ technical sheet
Appendix 4: Main results for all load cases identified for the 7.625x 9 7/8 SET®
Appendix 5: Main results for all load cases identified for the 8.625 x 10 ¾” SET®
Appendix 6: Main results for all load cases identified for the high collapse cemented linEXX™
Appendix 7: Main results for all load cases identified for the high collapse non-cemented linEXX™
Appendix 8: Skarv pressure estimation plot

Appendix 1: Enventure GT 7.625 x 9 7/8" SET® technical sheet

ENVENTURE **SET® Solid Expandable System**

7.625 OD 39.00 lb/ft x 9.875 OD 62.8 lb/ft OHL
BP Norway
6507/5-J-4H Skarv
Conceptual Design

External Base Casing	
Nominal OD	9.875 in.
Weight	62.80 lb/ft
Nominal ID	8.625 in.
API Drift	8.500 in.
Connection Type	Vam Top
Connection ID	8.835 in.
Other ID Restriction	8.600 in.

Launcher	
Launcher OD	8.379 in.

Connection Sleeves	
Set in Base Casing - Thickness	0.040 in.
Set in Base Casing - Expanded OD	8.605 in.
Set in Open Hole - Thickness	0.080 in.
Set in Open Hole - Expanded OD	8.681 in.

XPC Pre-Expansion Connection Specifications	
Tension Load Rating (1)	533,400 lb
Compressive Load Rating (2)	533,400 lb
Minimum Parting Load (3)	633,400 lb
Dogleg Severity Rating While Running	16.0 deg/100 ft

XPC Post-Expansion Connection Specifications	
Tension Load Rating (1)	570,100 lb
Compression Load Rating (2)	370,500 lb
Minimum Parting Load (3)	676,900 lb
Dogleg Severity Rating During Expansion	11.7 deg/100 ft

Well Bore Conditions (5)	
SET String Length	1,350 ft
Wellbore Maximum Dogleg Severity	3.0 deg/100 ft
Mud Weight	10.8 lb/gal
Bottomhole Temperature	200 °F
Nominal Open Hole ID	11.000 in.
Pilot Hole ID	8.500 in.

SET Liner Pre-Expansion	
SET Liner Grade	EX-80
Connection Type	GIIC
Nominal Yield Strength	80,000 psi
Minimum Ultimate Strength	95,000 psi
Nominal OD	7.625 in.
Nominal ID	6.625 in.
API Drift ID	6.500 in.
Nominal Wall Thickness	0.500 in.
Weight	39.00 lb/ft
Internal Yield	8,970 psi

SET Liner Post-Expansion	
Nominal OD	8.529 in.
Nominal ID	7.580 in.
Drift ID	7.504 in.
Nominal Wall Thickness	0.475 in.
Nominal Weight	40.51 lb/ft
Internal Yield	7,610 psi
Collapse Rating (4)	4,570 psi
Expansion Ratio	14.4%

Anchor Hanger	
Set in Base Casing - Elastomer Thickness	0.120 in.
Pre-Exp Seal OD in Base Casing	7.865 in.
Post-Exp OD in Base Casing	8.757 in.
Clad in Base Casing (nominal)	55.1%

Ratings are Based on Stated Bottomhole Temperature

(1) Joint strength is the elastic limit or yield strength of the connection
(2) Based on Connection NOT Utilizing Connection Sleeves
(3) Reference minimum parting load is the ultimate strength or parting load of the connection
(4) Design collapse strength is calculated for 99.5% reliability (0.5% target reliability level) using post-expansion SET® collapse test data and ISO 10400 collapse calculation method G.4.1. All testing procedures followed API 5C3 / ISO 10400 guidelines.
(5) Changes in wellbore conditions or whipstock configuration may require design review.

SET Design Sheet, Rev B   Engr: M. Camatta   Date Printed: 11-Oct-2012

Appendix 2: Enventure GT 8.625 x 10 3/4" SET® technical sheet

ENVENTURE **SET® Solid Expandable System**

8.625 OD 44.00 lb/ft x 10.750 OD 55.5 lb/ft OHL
BP Norway
6507/5-J-4H Skarv
Conceptual Design

External Base Casing

Nominal OD	10.750 in.
Weight	55.50 lb/ft
Nominal ID	9.760 in.
API Drift	9.604 in.
Connection Type	Tenaris Blue
Connection ID	9.754 in.
Other ID Restriction	9.754 in.

Launcher

Launcher OD	9.294 in.

Connection Sleeves

Set in Base Casing - Thickness	0.040 in.
Set in Base Casing - Expanded OD	9.632 in.
Set in Open Hole - Thickness	0.080 in.
Set in Open Hole - Expanded OD	9.708 in.

XPC Pre-Expansion Connection Specifications

Tension Load Rating (1)	608,000 lb
Compressive Load Rating (2)	608,000 lb
Minimum Parting Load (3)	722,000 lb
Dogleg Severity Rating While Running	14.1 deg/100 ft

XPC Post-Expansion Connection Specifications

Tension Load Rating (1)	647,100 lb
Compression Load Rating (2)	420,600 lb
Minimum Parting Load (3)	768,500 lb
Dogleg Severity Rating During Expansion	12.1 deg/100 ft

Well Bore Conditions (5)

SET String Length	1,350 ft
Wellbore Maximum Dogleg Severity	3.0 deg/100 ft
Mud Weight	10.8 lb/gal
Bottomhole Temperature	200 °F
Nominal Open Hole ID	11.000 in.
Pilot Hole ID	8.500 in.

SET Liner Pre-Expansion

SET Liner Grade	EX-80
Connection Type	GHC
Nominal Yield Strength	80,000 psi
Minimum Ultimate Strength	95,000 psi
Nominal OD	8.625 in.
Nominal ID	7.625 in.
API Drift ID	7.500 in.
Nominal Wall Thickness	0.500 in.
Weight	44.00 lb/ft
Internal Yield	7,930 psi

SET Liner Post-Expansion

Nominal OD	9.555 in.
Nominal ID	8.600 in.
Drift ID	8.514 in.
Nominal Wall Thickness	0.478 in.
Nominal Weight	45.93 lb/ft
Internal Yield	6,840 psi
Collapse Rating (4)	3,770 psi
Expansion Ratio	12.8%

Anchor Hanger

Set in Base Casing - Elastomer Thickness	0.180 in.
Pre-Exp Seal OD in Base Casing	8.985 in.
Post-Exp OD in Base Casing	9.899 in.
Clad in Base Casing (nominal)	38.6%

Ratings are Based on Stated Bottomhole Temperature

(1) Joint strength is the elastic limit or yield strength of the connection
(2) Based on Connection NOT Utilizing Connection Sleeves
(3) Reference minimum parting load is the ultimate strength or parting load of the connection
(4) Design collapse strength is calculated for 99.5% reliability (0.5% target reliability level) using post-expansion SET® collapse test data and ISO 10400 collapse calculation method G.4.1. All testing procedures followed API 5C3 / ISO 10400 guidelines.
(5) Changes in wellbore conditions or whipstock configuration may require design review.

ENVENTURE DOES NOT GUARANTEE THE ACCURACY OF ANY WELL DESIGN BASED UPON THIS TOOL OR ANY INTERPRETATION THAT THIS TOOL MAY ALLOW OR BASED UPON ANY RECOMMENDATIONS THAT MAY BE GIVEN BY ENVENTURE'S PERSONNEL OR IN ANY OTHER FORM.

ANY USER OF THIS TOOL OR THE DATA OR DESIGNS CREATED BY IT OR BY ENVENTURE'S PERSONNEL AGREES THAT ENVENTURE IS NOT RESPONSIBLE, EXCEPT WHERE DUE TO ENVENTURE'S GROSS NEGLIGENCE OR WILLFUL MISCONDUCT, FOR ANY LOSS, DAMAGES, OR EXPENSES RESULTING FROM SUCH USE.

SET Design Sheet, Rev B — Engr: M. Camatta — Date Printed: 15-Oct-2012

Appendix 3: Baker Hughes linEXX™ technical sheet

linEXX™ System – Monobore Casing Extension

Field Application – Temporary Drilling Liner

BAKER HUGHES

linEXX™ System Specifications Guide				
System Description	Standard (.345" Wall)		Higher Collapse (.400" Wall)	
Intermediate Casing Size (in.)	9.625" - 9.875"		9.625" – 9.875"	
Intermediate Casing Pass Thru I.D. (in.)	Min Drift 8.50"		Min Drift 8.50"	
RC9 Recess Shoe OD (non-cementable) (in.)	10.250"		10.250"	
RC9- R Recess Shoe OD (cementable) (in.)	11.250"		11.250"	
Min. Open Hole Size for linEXX liner (in.)	Cement 10.250"	No Cement 9.50"	Cement 10.250"	No Cement 9.75"
Temperature Rating (° Fahrenheit)	350		300	
Hanger Load (lbs)	500,000[4]		375,000[7]	
Hanger Burst (psi)	5,000[4]		5,670[4]	
Hanger Collapse (psi)	1,200[5]		2,309[5]	
linEXX Pipe Size	8.000" 28.20#		8.000" 32.46#	
Pipe Metallurgy	L80 Variant BMS C141		Sumitomo SX50	
Connection Type	BHI linEXX LH		TenarisHydril 723 LH	
Connection Integral or Coupled	Coupled		Integral	
Connection Direction	Left Hand		Left Hand	
Connection ID Pre-Expansion (in.)	7.400		7.104	
Connection OD Pre-Expansion (in.)	8.250		8.288 (max)	
Connection Make Up Torque (ft/lbs)	4375 Optimum		7000 Optimum	
Pre-Expansion ID (in.)	7.310		7.200	
Pre-Expansion Drift (in.)	7.185		7.075	
Pre-Expansion Burst (psi)	5,000[4]		5,000[5]	
Pre-Expansion Collapse (psi)	1,500[4]		3,800[5]	
Pre-Expansion Tensile Limit (lbs)	350,000[2]		300,000[3]	
Pre-Expansion Compressive Limit (lbs)[6]	125,000[3]		125,000[5]	
Max Running Length (ft)	3,000		3,000	
Expansion Percentage (%)	18.0		19.8	
Expansion Force (lbs)	240,000[2]		240,000[2]	
Expansion Pressure on linEXX Tools (psi)	3,000[2]		3,000[2]	
Free End Expansion Liner Shortening (%)	4.0[2]		5.0[2]	
Post-Expansion OD (in.) (Connection OD)	9.287 (9.335)		9.348 (9.670)	
Post-Expansion ID (Cone OD) (in.)	8.675 (8.625)		8.600 (8.625)	
Post-Expansion Drift (in.)	8.500[2]		8.500[2]	
Post-Expansion Burst (psi)	5,000[1]		5,670[7]	
Post-Expansion Collapse (psi)	1,200[1]		2,309[7]	
Post-Expansion Tensile Limit (lbs)	400,000[3]		441,000[7]	
Post-Expansion Compressive Limit (lbs)	350,000[3]		312,000[7]	

[1] These values have been confirmed through temperature testing and a safety factor has been applied
[2] These values have been tested at ambient temperature and are provided without safety factor
[3] These values have been tested at ambient temperature and a safety factor has been applied to correct for temperature effect on material
[4] These values have not been confirmed with testing, but are taken from previous design generation test results and have been confirmed as conservative values via all relevant calculations and running experience
[5] These values have not been tested. They have been derived via related experience and relevant calculations with appropriate safety factors included
[6] These limits are determined as the system rating rather than individual component
[7] These values have been tested at ambient temperature and are provided with a safety factor

Baker Hughes **Revised - 05/01/2012**

Appendix 4: Main results for all load cases identified for the 7.625x 9 7/8 SET®

Main results for all load cases identified for the 7.625 x 9 7/8 SET®												
Phase	Service Life Load Condition	Stresscheck Load Case	PP s.g	FG s.g	MW s.g	Internal Pressure	External Pressure	Burst (1.10) 7.625 x 9 7/8 SET®	Collapse (1.00) 7.625 x 9 7/8 SET®	Axial (1.40) 7.625 x 9 7/8 SET®	Triaxial (1.25) 7.625 x 9 7/8 SET®	Comments
During Installation	Running casing	**Axial:**	1,1	1,9	1,3	MW while running, 1.30 sg (OBM)	MW while running, 1.30 sg (OBM)	NA	NA	3,09	2,28	• Max average running speed from previous runs + 10%SF is used; 0.242m/s.
		- Running speed	0,9	1,5	1,3	MW while running, 1.30 sg (OBM)	MW while running, 1.30 sg (OBM)	NA	NA	3,05	2,59	• Max overpull is set to100tonn (derrick rating Polar Pioneer)
		- Applying over pull force on string	0,7	1,4	1,1	MW wile running 1.10 sg (OBM)	MW wile running 1.10 sg (OBM)	NA	NA	3,05	2,59	
		- Static load condition prior to cement operation	0,5	1,3	1,0	MW while running, 1.00 sg (OBM)	MW while running, 1.00 sg (OBM)	NA	NA	3,03	2,61	
		Burst: N/A **Collapse: N/A**	0,3	0,8	1,2	MW while running, 0.8 sg (OBM)	MW while running, 0.8 sg (OBM)	NA	NA	3,00	2,66	
	Conventional cement job	**Axial:**	1,1	1,9	1,3	MW while running and displacing 1.30 sg (OBM)	Cement slurry 1.65 sg. Liner fully cemented	NA	8,73/5,72*	-8,92/-7,31*	24,73/21,05*	• Worst case for collapse with wet cement in the full length of the liner. • * analyzed for both pre and post expanded liner.
		- Static load condition prior to cement operation - Static load condition post cementing operation	0,9	1,5	1,3	MW while running and displacing 1.30 sg (OBM)	Cement slurry 1.65 sg. Liner fully cemented	NA	8,73/5,55*	-8,92/-7,23*	24,73/20,96*	
		Burst: N/A	0,7	1,4	1,1	MW while running and displacing 1.10 sg (OBM)	Cement slurry 1.65 sg. Liner fully cemented	NA	9,69/6,16*	-9,75/-7,87*	24,39/20,71*	
		Collapse: - Cement	0,5	1,3	1,0	MW while running and displacing 1.00 sg (OBM)	Cement slurry 1.65 sg. Liner fully cemented	NA	10,26/6,50*	-10,22/-8,23*	24,17/20,56*	

			0,3	0,8	1,2	MW while running and displacing 0.8 sg (OBM)	Cement slurry 1.65 sg. Liner fully cemented	NA	11,60/7,36*	-11.31/-9,70*	23,68/20,21*	
	Bumping plug and pressure test casing (green cement)	**Axial:** - Static load condition prior to cement operation - Static load condition post cementing operation - Pressure test after landing the plug, green cement **Burst:** - Green Cement Pressure Test **Collapse: N/A**	1,1	1,9	1,3	345 surface pressure, 1.30 sg OBM	Fluid gradient w/pore pressure	1,5	NA	4,47	2,13	• The pressure seen at the linEXX casing shoe from an influx in Tilje will not exceed the shoe strength based on the obtained LOTs. LOT's expected to be +/-2.00sg. Max WH pressure is therefore the highest formation pressure with flow potential with gas column all the way up to WH, 384 bar at 3657 mTVD. Tilje gas gradient is believed to be similar to garn gas gradient 0.08psi/ft (0.184sg). A surface pressure of 308bar is required with 1.30sg brine. With a SF of 10% a pressure test of 340bar must be obtained. A surface pressure of 327 bar is required with 0.8sg brine. With a SF of 10% a pressure test of 360 bar must be obtained. However is it unrealistic that a 0,8sg brine will be used as test fluid. It is therefore sufficient to test the liner to 345bar.
			0,9	1,5	1,3	345 surface pressure, 1.30 sg OBM	Fluid gradient w/pore pressure	1,5	NA	4,47	2,13	
			0,7	1,4	1,1	345 surface pressure, 1.10 sg OBM	Fluid gradient w/pore pressure	1,5	NA	4,28	2,13	
			0,5	1,3	1,0	345 surface pressure, 1.00 sg OBM	Fluid gradient w/pore pressure	1,5	NA	4,19	2,14	
			0,3	0,8	1,2	345surface pressure, 0,8 sg OBM	Fluid gradient w/pore pressure	1,5	NA	4	2,14	
Burst Loads after Installation	**Pressure test after the cement is set up (WOC or drilling next section):**	**Axial:** - Static load condition post cementing operation **Burst:** - Pressure test	1,1	1,9	1,3	345 bar surface pressure, 1.30 OBM	Fluid gradient w/pore pressure	1,06	NA	-7,31	1,48	• Same criteria as green cement pressure test.
						325 bar surface pressure, 1.30 OBM	Fluid gradient w/pore pressure	1,10	NA	-7,23	1,55	
			0,9	1,5	1,3	345 bar surface pressure, 1.30 OBM	Fluid gradient w/pore pressure	1,06	NA	-7,23	1,47	
						325 bar surface pressure, 1.30 OBM	Fluid gradient w/pore pressure	1,10	NA	-7,23	1,53	
			0,7	1,4	1,1	345 bar surface pressure, 1.10 OBM	Fluid gradient w/pore pressure	0,93	NA	-7,87	1,29	
						255bar surface pressure, 1.10 OBM	Fluid gradient w/pore pressure	1,10	NA	-7,87	1,53	

		Collapse: N/A				345 bar surface pressure, 0.70 OBM	Fluid gradient w/pore pressure	1,10	NA	-7,87	1,53	
			0,5	1,3	1,0	345 bar surface pressure, 1.0 OBM	Fluid gradient w/pore pressure	0,98	NA	-8,23	1,37	
						290 bar surface pressure, 1.0 OBM	Fluid gradient w/pore pressure	1,10	NA	-8,23	1,53	
						345 bar surface pressure, 0.80 OBM	Fluid gradient w/pore pressure	1,10	NA	-8,23	1,53	
			0,3	0,8	1,2	360 bar surface pressure ,0.8 OBM	Fluid gradient w/pore pressure	0,98	NA	-9,7	1,37	
						290 bar surface pressure ,0.8 OBM	Fluid gradient w/pore pressure	1,10	NA	-9,7	1,53	
						345 bar surface pressure ,0.65 OBM	Fluid gradient w/pore pressure	1,10	NA	-9,07	1,53	
	Drilling -well control	**Axial:** - Static load condition post cementing operation	1,1	1,9	1,3	Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1,27	NA	-7,31	2,17	Expected LOT's = +/-2.00sg Tilje gas gradient similar to Garn gas gradient 0.08psi/ft =0.184sg Fracture gradient is calculated based on XXX SF of 0.05sg is included to the fracture gradient in StressCheck to cover the range of expected leak-off values
			0,9	1,5	1,3	Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1,56	NA	-7,23	2,21	

		Burst: - Frac @ shoe with gas gradient above shoe	0,7	1,4	1,1	Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,35	NA	-7,87	1,92	
			0,5	1,3	1,0	Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.00 sg OBM below shoe	Fluid gradient w/pore pressure	1,18	NA	-8,23	1,69	
		Collpase: N/A	0,3	0,8	1,2	Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,06	NA	-9,7	1,51	
				0.6		Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,10	NA	-9,7	1,5	
	Drilling -well control	**Axial:** - Static load condition post cementing operation	1,1	1,9	1,3	SW gradient from fracture point (shoe) to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1,34	NA	-7,31	1,78	Same case as above only with water filled wellbore.
			0,9	1,5	1,3	SW gradient from fracture point (shoe) to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1,65	NA	-7,23	2,08	
			0,7	1,4	1,1	SW gradient from fracture point (shoe) to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1,41	NA	-7,87	1,87	

		Burst: - Lost returns with water	0.5	1,3	1.0	SW gradient from fracture point (shoe) to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,23	NA	-8,23	1,67	
			0,3	0,8	1,2	SW gradient from fracture point (shoe) to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,09	NA	-9,07	1,51	
		Collpase: N/A	0,3	0,5	1,2	SW gradient from fracture point (shoe) to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,10	NA	-9,07	1,53	
	Injection down string **well kill or workover**	**Axial:** - Static load condition post cementing operation	1,1	1,9	1,3	Closed WH pressure @ 339 bar + 1.30 sg kill mud	Fluid gradient w/pore pressure	1,09	NA	-7,31	4,38	Closed WH with reservoir pressure trapped from TD of 8 1/2" section to WH as worst case The kick is bullheaded back into the formation. Kill fluid in each case are equal to the respectively MW.
			0,9	1,5	1,3	Closed WH pressure @ 339 bar + 1.30 sg kill mud	Fluid gradient w/pore pressure	1,08	NA	-7,23	1,83	
						Closed WH pressure @ 215 bar + 1.30 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-7,23	1,83	
		Burst: -Injection down casing	0,7	1,4	1,1	Closed WH pressure @ 348 bar + 1.10 sg kill mud	Fluid gradient w/pore pressure	1,08	NA	-7,87	1,49	
						Closed WH pressure @ 334 bar + 1.10 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-7,87	1,51	
						Closed WH pressure @ 348 bar + 1.08 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-7,87	1,51	

Collapse Loads after Installation		**Collpase: N/A**	0,5	1,3	1,0	Closed WH pressure @ 352 bar + 1.00 sg kill mud	Fluid gradient w/pore pressure	1,01	NA	-8,23	1,4	
						Closed WH pressure @ 302 bar + 1.00 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-8,23	1,52	
						Closed WH pressure @ 352 bar + 0.88 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-8,23	1,52	
			0,3	0,8	1,2	Closed WH pressure @ 360 bar + 0.8 sg kill mud	Fluid gradient w/pore pressure	1,01	NA	-9,07	1,4	
						Closed WH pressure @ 302 bar + 0.8 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-9,07	1,52	
						Closed WH pressure @ 360 bar + 0.67 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-9,07	1,52	
	Lost circulation while drilling	**Axial:** - Static load condition post cementing operation	1,1	1,9	1,3	Mud drop level = 686 m with a pore pressure EMW of 1.058 sg and 1.30 sg OBM.	Fluid gradient w/pore pressure	NA	2,41	-7,31	4,61	• Lost return depth 5450mMD
			0,9	1,5	1,3	Mud drop level = 682 m with 1.30 sg OBM	Fluid gradient w/pore pressure	NA	2,41	-7,23	4,66	
			0,7	1,4	1,1	Mud drop level = 139.96 m with a pore pressure EMW of 1.058sg and 1.10 sg OBM	Fluid gradient w/pore pressure	NA	5,15	-7,87	6,02	

	Burst: N/A	0,5	1,3	1,0	Mud drop level = 0 m with a pore pressure EMW of 1.058 sg and 1.00 sg OBM	Fluid gradient w/pore pressure	NA	13,5	-8,23	6,02	
	Collapse: - Lost circulation with mud drop	0,3	0,8	1,2	Mud drop level = 0m with a pore pressure EMW of 1.058 sg and 0.8 sg OBM	Fluid gradient w/pore pressure	NA	-	-	-	
Pressures Above/Below Packer **worst during operation**	**Axial:** - Static load condition post cementing operation	1,1	1,9	1,3	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	2,35	-7,31	7,41	• Fluid drop may occur due to the hydrostatic head of the fluid equilibrating with the depleted pressure at the perforations. Fully evacuated casing below packer to gas gradient.
		0,9	1,5	1,3	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	2,36	-7,23	6,26	
	Burst: N/A	0,7	1,4	1,1	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	5,18	-7,87	19,59	
		0,5	1,3	1,0	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	12,29	.8,23	20,12	
	Collpase: - Above/Below Packer -	0,3	0,8	1,2	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	-	-	-	

Resulting in minimum safety factor for all of the service life load condition, SF higher than BP Skarv design factor

Safety factor higher than minimum required safety factor for all of the service life load conditions

SF lower than minimum required

Compression

Not applicable for the load case

Appendix 5: Main results for all load cases identified for the 8.625 x 10 ¾" SET®

Main results for all load cases identified for the 8.625 x 10 3/4 SET®												
Phase	Service Life Load Condition	Stresscheck Load Case	PP s.g	FG s.g	MW s.g	Internal Pressure	External Pressure	Burst (1.10) 8.625 x 10 3/4 SET®	Collapse (1.00) 8.625 x 10 3/4 SET®	Axial (1.40) 8.625 x 10 3/4 SET®	Triaxial (1.25) 8.625 x 10 3/4 SET®	Comments
During Installation	Running casing	**Axial:** - Running speed	1,1	1,9	1,3	MW while running 1.30 sg (OBM)	MW while running 1.30 sg (OBM)	NA	NA	3,11	2,49	• Max average running speed from previous runs + 10%SF is used; 0.242m/s.
			0,9	1,5	1,3	MW while running 1.30 sg (OBM)	MW while running 1.30 sg (OBM)	NA	NA	3,11	2,48	• Max overpull is set to100tonn (derrick rating Polar Pioneer)
		- Applying over pull force on string	0,7	1,4	1,1	MW while running 1.30 sg (OBM)	MW while running 1.30 sg (OBM)	NA	NA	3,07	2,53	
		- Static load condition prior to cement operation	0,5	1,3	1,0	MW while running 1.30 sg (OBM)	MW while running 1.30 sg (OBM)	NA	NA	3,05	2,56	
		Burst: N/A **Collapse: N/A**	0,3	0,8	1,2	MW while running 1.30 sg (OBM)	MW while running 1.30 sg (OBM)	NA	NA	3,01	2,62	
	Conventional cement job	**Axial:**	1,1	1,9	1,3	MW while running and displacing 1.30 sg (OBM)	Cement slurry 1.65 sg. Liner fully cemented	NA	8,35/5,23	-7,28/-6,12	18,44/18,95	• Worst case for collapse with wet cement in the full length of the liner.
		- Static load condition prior to cement operation - Static load condition post cementing operation	0,9	1,5	1,3	MW while running and displacing 1.30 sg (OBM)	Cement slurry 1.65 sg. Liner fully cemented	NA	8,12/5,07	-7,21/-6,05	18,36/18,87	
		Burst: N/A	0,7	1,4	1,1	MW while running and displacing 1.30 sg (OBM)	Cement slurry 1.65 sg. Liner fully cemented	NA	9,02/5,59	-7,85/-6,55	18,17/18,65	
		Collapse: - - -Cement	0,5	1,3	1,0	MW while running and displacing 1.30 sg (OBM)	Cement slurry 1.65 sg. Liner fully cemented	NA	9,56/5,89	-8,21/-6,83	18,05/18,51	

			0,3	0,8	1,2	MW while running and displacing 1.30 sg (OBM)	Cement slurry 1.65 sg. Liner fully cemented	NA	10,84/6,60	-9,05/-7,47	17,77/18,20	
	Bumping plug and pressure test casing (green cement)	**Axial:** - Static load condition prior to cement operation - -Static load condition post cementing operation - ---Pressure test after landing the plug, green cement **Burst:** - Green Cement Pressure Test **Collapse: N/A**	1,1	1,9	1,3	345 surface pressure, 1.30sg (OBM)	Fluid gradient w/pore pressure	1,34	NA	3,35	1,93	• The pressure seen at the linEXX casing shoe from an influx in Tilje will not exceed the shoe strength based on the obtained LOTs. LOT's expected to be +/-2.00sg. Max WH pressure is therefore the highest formation pressure with flow potential with gas column all the way up to WH, 384 bar at 3657 mTVD. Tilje gas gradient is believed to be similar to garn gas gradient 0.08psi/ft (0.184sg). A surface pressure of 308bar is required with 1.30sg brine. With a SF of 10% a pressure test of 340bar must be obtained. A surface pressure of 327 bar is required with 0.8sg brine. With a SF of 10% a pressure test of 360 bar must be obtained. However is it unrealistic that a 0,8sg brine will be used as test fluid? It is therefore sufficient to test the liner to 345bar.
			0,9	1,5	1,3	346 surface pressure, 1.30sg (OBM)	Fluid gradient w/pore pressure	1,34	NA	3,37	1,93	
			0,7	1,4	1,1	347 surface pressure, 1.30sg (OBM)	Fluid gradient w/pore pressure	1,34	NA	3,23	1,93	
			0,5	1,3	1,0	348 surface pressure, 1.30sg (OBM)	Fluid gradient w/pore pressure	1,34	NA	3,17	1,93	
			0,3	0,8	1,2	349 surface pressure, 1.30sg (OBM)	Fluid gradient w/pore pressure	1,34	NA	3,05	1,93	
Burst Loads after Installation	**Pressure test after the cement is set up (WOC or drilling next section):**	**Axial:** - Static load condition post cementing operation **Burst:**	1,1	1,9	1,3	345 bar surface pressure, 1.30sg (OBM)	Fluid gradient w/pore pressure	0,95	NA	-6,12	1,33	• Same criteria as green cement pressure test.
						283 bar surface pressure, 1.30sg (OBM)	Fluid gradient w/pore pressure	1,10	NA	-6,12	1,53	
			0,9	1,5	1,3	345 bar surface pressure, 1.30sg (OBM)	Fluid gradient w/pore pressure	0,95	NA	-6,05	1,33	
						280 bar surface pressure, 1.30sg (OBM)	Fluid gradient w/pore pressure	1,10	NA	-6,05	1,53	

		- Pressure test	0,7	1,4	1,1	345 bar surface pressure, 1.10sg (OBM)	Fluid gradient w/pore pressure	0,95	NA	-6,55	1,33	
						280 bar surface pressure, 1.10sg (OBM)	Fluid gradient w/pore pressure	1,10	NA	-6,55	1,54	
			0,5	1,3	1,0	345 bar surface pressure, 1.00sg (OBM)	Fluid gradient w/pore pressure	0,88	NA	-6,83	1,24	
						245 bar surface pressure, 1.00sg (OBM)	Fluid gradient w/pore pressure	1,10	NA	-6,83	1,54	
			0,3	0,8	1,2	345 bar surface pressure, 0.8sg (OBM)	Fluid gradient w/pore pressure	0,88	NA	-7,47	1,24	
		Collapse: N/A				245 bar surface pressure, 0.8sg (OBM)	Fluid gradient w/pore pressure	1,10	NA	-7,47	1,53	
			1,1	1,9	1,3	Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1,14	NA	-10,92	1,65	Expected LOT's = +/-2.00sg Tilje gas gradient similar to Garn gas gradient 0.08psi/ft =0.184sg Fracture gradient is calculated based on XXX SF of 0.05sg is included to the fracture gradient in StressCheck to cover the range of expected leak-off values
	Drilling -well control	**Axial:** - Static load condition post cementing operation	0,9	1,5	1,3	Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1,4	NA	-6,05	1,33	
			0,7	1,4	1,1	Tilje gas gradient	Fluid gradient	1,21	NA	-6,55	1,74	

						0.08 psi/ft at frac pressure from shoe to WH, 1.10 sg OBM below shoe	w/pore pressure					
		Burst: - Frac @ shoe with gas gradient above shoe	0,5	1,3	1,0	Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.00 sg OBM below shoe	Fluid gradient w/pore pressure	1,06	NA	-6,83	1,53	
				1,21		Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,10	NA	-6,83	1,58	
			0,3	0,8	1,2	Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	0,95	NA	-7,47	1,36	
		Collpase: N/A		0,8		Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,10	NA	-7,47	1,59	
	Drilling -well control	**Axial:**	1,1	1,9	1,3	SW gradient from fracture point (shoe) to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1,21	NA	-10,92	1,63	Same case as above only with water filled wellbore.

		- Static load condition post cementing operation	0,9	1,5	1,3	SW gradient from fracture point (shoe) to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1,47	NA	-6,05	1,92	
			0,7	1,4	1,1	SW gradient from fracture point (shoe) to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1,26	NA	-6,55	1,7	
		Burst: - Lost returns with water	0.5	1,3	1.0	SW gradient from fracture point (shoe) to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,11	NA	-6,83	1,53	
			0,3	0,8	1,2	SW gradient from fracture point (shoe) to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	0,98	NA	-7,47	1,38	
		Collpase: N/A	0,3	0,9	1,2	SW gradient from fracture point (shoe) to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,10	NA	-7,47	1,52	
	Injection down string **well kill or workover**	**Axial:** - Static load condition post cementing operation	1,1	1,9	1,3	Closed WH pressure @ 345 bar + 1.30 sg kill mud	Fluid gradient w/pore pressure	0,98	NA	-10,92	1,37	Closed WH with reservoir pressure trapped from TD of 8 1/2" section to WH as worst case The kick is bullheaded back into the formation. Kill fluid in each case are equal to the respectively MW.
			0,9	1,5	1,3	Closed WH pressure @ 345 bar + 1.30 sg kill mud	Fluid gradient w/pore pressure	0,97	NA	-6,05	1,36	
						Closed WH pressure @ 290 bar + 1.30 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-6,05	1,51	

		Burst: -Injection down casing	0,7	1,4	1,1	Closed WH pressure @ 345 bar + 1.10 sg kill mud	Fluid gradient w/pore pressure	1,05	NA	-6,55	1,45	
						Closed WH pressure @ 325 bar + 1.10 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-6,55	1,52	
						Closed WH pressure @ 345 bar + 0.94 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-6,55	1,52	
			0,5	1,3	1,0	Closed WH pressure @ 345 bar + 1.00 sg kill mud	Fluid gradient w/pore pressure	0,91	NA	-6,83	1,28	
						Closed WH pressure @ 255 bar + 1.00 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-6,83	1,53	
						Closed WH pressure @ 345 bar + 0.74 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-6,83	1,53	
		Collpase: N/A	0,3	0,8	1,2	Closed WH pressure @ 345 bar + 0.8 sg kill mud	Fluid gradient w/pore pressure	0,91	NA	-7,47	1,28	
						Closed WH pressure @ 255bar + 0.8 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-7,47	1,52	
						Closed WH pressure @ 345 bar + 0.54 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-7,47	1,52	
Collapse Loads after Installation	**Lost circulation while drilling**	**Axial:**	1,1	1,9	1,3	Mud drop level = 623 m with a pore pressure EMW of 1.058 sg and 1.30 sg OBM	Fluid gradient w/pore pressure	NA	2,06	-10,92	4,34	• Lost return depth 5450mMD

		- Static load condition post cementing operation	0,9	1,5	1,3	Mud drop level = 654 m with 1.30 sg OBM	Fluid gradient w/pore pressure	NA	2,07	-6,05	4,39	
		Burst: N/A	0,7	1,4	1,1	Mud drop level = 723 m with a pore pressure EMW of 0.877 sg and 1.10 sg OBM	Fluid gradient w/pore pressure	NA	4,61	-6,55	5,83	
			0,5	1,3	1,0	Mud drop level = 802 m with a pore pressure EMW of 0.784 sg and 1.00 sg OBM	Fluid gradient w/pore pressure	NA	13,84	-6,83	6,19	
		Collapse: - Lost circulation with mud drop	0,3	0,8	1,2	Mud drop level = 517 m with a pore pressure EMW of 0.691 sg and 0.8 sg OBM	Fluid gradient w/pore pressure	NA	-	-	-	
	Pressures Above/Below Packer **worst during operation**	**Axial:** - Static load condition post cementing operation	1,1	1,9	1,3	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	2,02	-10,92	6,65	• Fluid drop may occur due to the hydrostatic head of the fluid equilibrating with the depleted pressure at the perforations. Fully evacuated casing below packer to gas gradient.
			0,9	1,5	1,3	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	2,02	-6,05	6,66	
		Burst: N/A	0,7	1,4	1,1	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	4,62	-6,55	16,75	
			0,5	1,3	1,0	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	12,26	-6,83	14,15	
		Collpase: -----Above/Below Packer	0,3	0,8	1,2	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	-	-	-	

Blue	Resulting in minimum safety factor for all of the service life load condition, SF higher than BP Skarv design factor
Red	Safety factor higher than minimum required safety factor for all of the service life load conditions
Yellow	SF lower than minimum required
Green	Compression
Grey	Not applicable for the load case

Appendix 6: Main results for all load cases identified for the high collapse cemented linEXX™

Main results for all load cases identified for the high collapse cement linEXX												
Phase	Service Life Load Condition	Stresscheck Load Case	PP s.g	FG s.g	MW s.g	Internal Pressure	External Pressure	Burst (1.10) high collapse cement linEXX	Collapse (1.00) high collapse cement linEXX	Axial (1.40) high collapse cement linEXX	Triaxial (1.25) high collapse cement linEXX	Comments
During Installation		**Axial:**	1,1	1,9	1,3	MW wile running 1.30 sg (OBM)	MW wile running 1.30 sg (OBM)	NA	NA	2,22	1,37	• Max average running speed from previous runs + 10%SF is used; 0.242m/s. • Max overpull is set to100tonn (derrick rating Polar Pioneer)
		- Running speed	0,9	1,5	1,3	MW wile running 1.30 sg (OBM)	MW wile running 1.30 sg (OBM)	NA	NA	2,83	2,73	
	Running casing	- Applying over pull force on string	0,7	1,4	1,1	MW wile running 1.10 sg (OBM)	MW wile running 1.10 sg (OBM)	NA	NA	2,79	2,78	
		- Static load condition prior to cement operation	0,5	1,3	1,0	MW wile running 1.00 sg (OBM)	MW wile running 1.00 sg (OBM)	NA	NA	2,78	2,81	
		Burst: N/A **Collapse: N/A**	0,3	0,8	1,2	MW wile running 0.8 sg (OBM)	MW wile running 0.8 sg (OBM)	NA	NA	2,74	2,86	
		Axial: - Static load condition prior to cement operation "- Static load condition post cementing operation	1,1	1,9	1,3	MW while running and displacing 1.30 sg (OBM)	Cement slurry 1.65 sg. Liner fully cemented	NA	3,81	-6,91	20,53	• Worst case for collapse with wet cement in the full length of the liner.
			0,9	1,5	1,3	MW while running and displacing 1.30 sg (OBM)	Cement slurry 1.65 sg. Liner fully cemented	NA	3,81	-6,91	20,53	
	Conventional cement job	**Burst: N/A**	0,7	1,4	1,1	MW while running and displacing 1.10sg (OBM)	Cement slurry 1.65 sg. Liner fully cemented	NA	4,13	-7,45	20,16	
		Collapse: - Cement	0,5	1,3	1,0	MW while running and displacing 1.00sg (OBM)	Cement slurry 1.65 sg. Liner fully cemented	NA	4,32	-7,75	19,93	
			0,3	0,8	1,2	MW while running and displacing 0.8 sg (OBM)	Cement slurry 1.65 sg. Liner fully cemented	NA	4,74	-8,43	19,41	

	Bumping plug and pressure test casing (green cement)	**Axial:** - Static load condition prior to cement operation - Static load condition post cementing operation - Pressure test after landing the plug, green cement **Burst:** - Green Cement Pressure Test **Collapse: N/A**	1,1	1,9	1,3	345 surface pressure, 1.30 OBM	Fluid gradient w/pore pressure	1,11	NA	3,03	1,65	• The pressure seen at the linEXX casing shoe from an influx in Tilje will not exceed the shoe strength based on the obtained LOTs. LOT's expected to be +/-2.00sg. Max WH pressure is therefore the highest formation pressure with flow potential with gas column all the way up to WH, 384 bar at 3657 mTVD. Tilje gas gradient is believed to be similar to garn gas gradient 0.08psi/ft (0.184sg). A surface pressure of 308bar is required with 1.30sg brine. With a SF of 10% a pressure test of 340bar must be obtained. A surface pressure of 327 bar is required with 0.8sg brine. With a SF of 10% a pressure test of 360 bar must be obtained. However is it unrealistic that a 0,8sg brine will be used as test fluid? It is therefore sufficient to test the liner to 345bar.
			0,9	1,5	1,3	345 surface pressure, 1.30 OBM	Fluid gradient w/pore pressure	1,11	NA	3,03	1,65	
			0,7	1,4	1,1	345 surface pressure, 1.10 OBM	Fluid gradient w/pore pressure	1,11	NA	2,94	1,65	
			0,5	1,3	1,0	345 surface pressure, 1.00 OBM	Fluid gradient w/pore pressure	1,11	NA	2,89	1,65	
			0,3	0,8	1,2	345 surface pressure, 0.8 OBM	Fluid gradient w/pore pressure	1,11	NA	2,81	1,65	
Burst Loads after Installation	**Pressure test after the cement is set up (WOC or drilling next section):**	**Axial:** - Static load condition post cementing operation **Burst:** - Pressure test	1,1	1,9	1,3	345 bar surface pressure, 1.30 OBM	Fluid gradient w/pore pressure	0,88	NA	-6,91	1,27	• Same criteria as green cement pressure test.
						260 bar surface pressure, 1.30 OBM	Fluid gradient w/pore pressure	1,10	NA	-6,91	1,58	
			0,9	1,5	1,3	345 bar surface pressure, 1.30 OBM	Fluid gradient w/pore pressure	0,79	NA	-6,91	1,13	
						206 bar surface pressure, 1.30 OBM	Fluid gradient w/pore pressure	1,10	NA	-6,91	1,58	
			0,7	1,4	1,1	345 bar surface pressure, 1.10 OBM	Fluid gradient w/pore pressure	0,79	NA	-7,45	1,13	
						206 bar surface pressure, 1.10 OBM	Fluid gradient w/pore pressure	1,10	NA	-7,45	1,58	
						345 bar surface pressure, 0.70 OBM	Fluid gradient w/pore pressure	1,10	NA	-7,45	1,58	
			0,5	1,3	1,0	345 bar surface pressure, 1.0 OBM	Fluid gradient w/pore pressure	0,73	NA	-7,75	1,06	

						172 bar surface pressure, 1.0 OBM	Fluid gradient w/pore pressure	1,10	NA	-7,75	1,57	
						345 bar surface pressure, 0.5 OBM	Fluid gradient w/pore pressure	1,10	NA	-7,75	1,58	
		Collapse: N/A	0,3	0,8	1,2	345 bar surface pressure ,0.8 OBM	Fluid gradient w/pore pressure	0,73	NA	-8,43	1,06	
						172 bar surface pressure ,0.8 OBM	Fluid gradient w/pore pressure	1,10	NA	-8,43	1,57	
						345 bar surface pressure ,0.3 OBM	Fluid gradient w/pore pressure	1,10	NA	-7,43	1,58	
			1,1	1,9	1,3	Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	0,95	NA	-6,91	1,4	Expected LOT's = +/-2.00sg Tilje gas gradient similar to Garn gas gradient 0.08psi/ft =0.184sg Fracture gradient is calculated based on XXX SF of 0.05sg is included to the fracture gradient in StressCheck to cover the range of expected leak-off values
		Axial: - Static load condition post cementing operation	0,9	1,5	1,3	Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1,16	NA	-6,91	1,71	
	Drilling -well control		0,7	1,4	1,1	Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1	NA	-7,45	1,48	
		Burst:		1,2		Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,10	NA	-7,45	1,62	

		- Frac @ shoe with gas gradient above shoe	0,5	1,3	1,0	Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.00 sg OBM below shoe	Fluid gradient w/pore pressure	0,88	NA	-7,75	1,3	
				0,78		Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,10	NA	-7,75	1,63	
		Collpase: N/A	0,3	0,8	1,2	Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	0,79	NA	-8,43	1,16	
				0.36		Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,10	NA	-8,43	1,63	
	Drilling -well control	**Axial:** - Static load condition post cementing operation	1,1	1,9	1,3	SW gradient from fracture point (shoe) to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1	NA	-6,91	1,45	Same case as above only with water filled wellbore.
			0,9	1,5	1,3	SW gradient from fracture point (shoe) to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1,22	NA	-6,91	1,72	
			0,7	1,4	1,1	SW gradient from fracture point (shoe) to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1,05	NA	-7,45	1,51	

				1,3		SW gradient from fracture point (shoe) to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1,10	NA	-7,45	1,57	
		Burst: - Lost returns with water	0.5	1,3	1.0	SW gradient from fracture point (shoe) to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	0,92	NA	-7,75	1,34	
				0,9		SW gradient from fracture point (shoe) to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,10	NA	-7,75	1,58	
			0,3	0,8	1,2	SW gradient from fracture point (shoe) to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	0,82	NA	-8,43	1,2	
		Collpase: N/A	0,3	0,5	1,2	SW gradient from fracture point (shoe) to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,10	NA	-7,43	1,57	
	Injection down string **well kill or workover**	**Axial:** - Static load condition post cementing operation	1,1	1,9	1,3	Closed WH pressure @ 345 bar + 1.30 sg kill mud	Fluid gradient w/pore pressure	0,91	NA	-6,91	1,32	Closed WH with reservoir pressure trapped from TD of 8 1/2" section to WH as worst case The kick is bullheaded back into the formation. Kill fluid in each case are equal to the respectively MW.
			0,9	1,5	1,3	Closed WH pressure @ 345 bar + 1.30 sg kill mud	Fluid gradient w/pore pressure	0,81	NA	-6,91	1,18	
						Closed WH pressure @ 215 bar + 1.30 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-6,91	1,58	
		Burst:	0,7	1,4	1,1	Closed WH pressure @ 345 bar + 1.10 sg kill mud	Fluid gradient w/pore pressure	0,81	NA	-7,45	1,18	

		Injection down casing				Closed WH pressure @ 215 bar + 1.10 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-7,45	1,58	
						Closed WH pressure @ 345 bar + 0.73 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-7,45	1,58	
			0,5	1,3	1,0	Closed WH pressure @ 345 bar + 1.00 sg kill mud	Fluid gradient w/pore pressure	0,75	NA	-7,75	1,11	
						Closed WH pressure @ 180 bar + 1.00 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-7,75	1,58	
						Closed WH pressure @ 345 bar + 0.52 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-7,5	1,59	
		Collpase: N/A	0,3	0,8	1,2	Closed WH pressure @ 345 bar + 0.8 sg kill mud	Fluid gradient w/pore pressure	0,75	NA	-8,43	1,11	
						Closed WH pressure @ 180 bar + 0.8 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-8,43	1,58	
						Closed WH pressure @ 345 bar + 0.33 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-8,43	1,58	
Collapse Loads after Installation	**Lost circulation while drilling**	**Axial:** - Static load condition post cementing operation	1,1	1,9	1,3	Mud drop level = 686 m with a pore pressure EMW of 1.058 sg and 1.30 sg OBM	Fluid gradient w/pore pressure	NA	1,35	-6,91	4,27	• Lost return depth 5450mMD
			0,9	1,5	1,3	Mud drop level = 682 m with 1.30 sg OBM	Fluid gradient w/pore pressure	NA	1,32	2,83	1,65	

	Burst: N/A	0,7	1,4	1,1	Mud drop level = 748 m with a pore pressure EMW of 0.877 sg and 1.10 sg OBM	Fluid gradient w/pore pressure	NA	1,45	-7,45	4,41	
		0,5	1,3	1,0	Mud drop level = 798 m with a pore pressure EMW of 0.784 sg and 1.00 sg OBM	Fluid gradient w/pore pressure	NA	1,52	-7,75	4,45	
	Collapse: - Lost circulation with mud drop	0,3	0,8	1,2	Mud drop level = 503 m with a pore pressure EMW of 0.691 sg and 0.8 sg OBM	Fluid gradient w/pore pressure	NA	2,4	-8,43	5,6	
Pressures Above/Below Packer **worst during operation**	**Axial:** - Static load condition post cementing operation	1,1	1,9	1,3	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	1,32	2,83	1,27	• Fluid drop may occur due to the hydrostatic head of the fluid equilibrating with the depleted pressure at the perforations. Fully evacuated casing below packer to gas gradient.
		0,9	1,5	1,3	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	1,32	-6,91	5,8	
	Burst: N/A	0,7	1,4	1,1	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	3,12	-7,45	16,21	
		0,5	1,3	1,0	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	9,93	-7,75	13,63	
	Collpase: -Above/Below Packer	0,3	0,8	1,2	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	-	-7,43	5,59	

(blue)	Resulting in minimum safety factor for all of the service life load condition, SF higher than BP Skarv design factor
(red)	Safety factor higher than minimum required safety factor for all of the service life load conditions
(yellow)	SF lower than minimum required
(green)	Compression
(grey)	Not applicable for the load case

APPENDIX 7: MAIN RESULTS FOR ALL LOAD CASES IDENTIFIED FOR THE HIGH COLLAPSE NON-CEMENTED LINEXX™

Main results for all load cases identified for the high collapse non-cement linEXX												
Phase	Service Life Load Condition	Stresscheck Load Case	PP s.g	FG s.g	MW s.g	Internal Pressure	External Pressure	Burst (1.10) 8.625 x 10 3/4 SET®	Collapse (1.00) 8.625 x 10 3/4 SET®	Axial (1.40) 8.625 x 10 3/4 SET®	Triaxial (1.25) 8.625 x 10 3/4 SET®	Comments
During Installation	Running casing	**Axial:** - Running speed - Applying over pull force on string - Static load condition prior to cement operation **Burst: N/A** **Collapse: N/A**	1,1	1,9	1,3	MW wile running 1.30 sg (OBM)	MW wile running 1.30 sg (OBM)	NA	NA	2,22	1,37	• Max average running speed from previous runs + 10%SF is used; 0.242m/s. • Max overpull is set to100tonn (derrick rating Polar Pioneer)
			0,9	1,5	1,3	MW wile running 1.30 sg (OBM)	MW wile running 1.30 sg (OBM)	NA	NA	2,28	1,39	
			0,7	1,4	1,1	MW wile running 1.10 sg (OBM)	MW wile running 1.10 sg (OBM)	NA	NA	2,26	1,42	
			0,5	1,3	1,0	MW wile running 1.00 sg (OBM)	MW wile running 1.00 sg (OBM)	NA	NA	2,22	1,43	
			0,3	0,8	1,2	MW wile running 0.8 sg (OBM)	MW wile running 0.8 sg (OBM)	NA	NA	2,22	1,45	
Burst Loads after Installation	Pressure test after the cement is set up (WOC or drilling next section):	**Axial:** - Static load condition post cementing operation **Burst:** - Pressure test	1,1	1,9	1,3	345 bar surface pressure, 1.30 OBM	Fluid gradient w/pore pressure	0,78	NA	-7,31	0,71	• Same criteria as green cement pressure test.
						210 bar surface pressure, 1.30 OBM	Fluid gradient w/pore pressure	1,10	NA	-5,39	0,71	
			0,9	1,5	1,3	345 bar surface pressure, 1.30 OBM	Fluid gradient w/pore pressure	0,78	NA	-5,39	0,71	
						206 bar surface pressure, 1.30 OBM	Fluid gradient w/pore pressure	1,10	NA	-5,39	1	
			0,7	1,4	1,1	345 bar surface pressure, 1.10 OBM	Fluid gradient w/pore pressure	0,77	NA	-5,96	1	

		Collapse: N/A				280 bar surface pressure, 1.10 OBM	Fluid gradient w/pore pressure	1,10	NA	-5,96	1,34		
						345 bar surface pressure, 0.70 OBM	Fluid gradient w/pore pressure	1,10	NA	-5,96	1,32		
			0,5	1,3	1,0	345 bar surface pressure, 1.0 OBM	Fluid gradient w/pore pressure	0,87	NA	-6,3	1		
						252 bar surface pressure, 1.0 OBM	Fluid gradient w/pore pressure	1,10	NA	-6,3	1,36		
						345 bar surface pressure, 0.39 OBM	Fluid gradient w/pore pressure	1,10	NA	-6,3	1,37		
			0,3	0,8	1,2	345 bar surface pressure ,0.8 OBM	Fluid gradient w/pore pressure	0,94	NA	-7,09	1		
						285 bar surface pressure ,0.8 OBM	Fluid gradient w/pore pressure	1,10	NA	-7,09	1,21		
						345 bar surface pressure ,0.53 OBM	Fluid gradient w/pore pressure	1,10	NA	-7,09	1,21		
	Drilling -well control	**Axial:** - Static load condition post cementing operation	1,1	1,9	1,3	Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1	NA	-7,31	1,39	Expected LOT's = +/-2.00sg Tilje gas gradient similar to Garn gas gradient 0.08psi/ft =0.184sg Fracture gradient is calculated based on XXX SF of 0.05sg is included to the fracture gradient in StressCheck to cover the range of expected leak-off values	
			0,9	1,5	1,3	Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1,17	NA	-5,39	1,1		

		Burst: - Frac @ shoe with gas gradient above shoe	0,7	1,4	1,1	Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,19	NA	-5,39	1,45	
			0,5	1,3	1,0	Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.00 sg OBM below shoe	Fluid gradient w/pore pressure	1,11	NA	-6,3	1,36	
		Collpase: N/A	0,3	0,8	1,2	Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,04	NA	-7,09	1,14	
				0.36		Tilje gas gradient 0.08 psi/ft at frac pressure from shoe to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,10	NA	-7,09	1,2	
	Drilling -well control	**Axial:** - Static load condition post cementing operation	1,1	1,9	1,3	SW gradient from fracture point (shoe) to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1,01	NA	-7,31	1,27	Same case as above only with water filled wellbore.
			0,9	1,5	1,3	SW gradient from fracture point (shoe) to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1,23	NA	-5,39	1,09	
			0,7	1,4	1,1	SW gradient from fracture point (shoe) to WH, 1.30 sg OBM below shoe	Fluid gradient w/pore pressure	1,21	NA	-5,39	1,35	

		Burst: - Lost returns with water	0.5	1,3	1.0	SW gradient from fracture point (shoe) to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,13	NA	-6,3	1,28	
		Collpase: N/A	0,3	0,8	1,2	SW gradient from fracture point (shoe) to WH, 1.10 sg OBM below shoe	Fluid gradient w/pore pressure	1,12	NA	-7,09	1,17	
	Injection down string well kill or workover	**Axial:** - Static load condition post cementing operation	1,1	1,9	1,3	Closed WH pressure @ 345 bar + 1.30 sg kill mud	Fluid gradient w/pore pressure	0,8	NA	-7,31	1,03	Closed WH with reservoir pressure trapped from TD of 8 1/2" section to WH as worst case The kick is bullheaded back into the formation. Kill fluid in each case are equal to the respectively MW.
			0,9	1,5	1,3	Closed WH pressure @ 345 bar + 1.30 sg kill mud	Fluid gradient w/pore pressure	1,04	NA	-5,39	0,94	
						Closed WH pressure @ 322 bar + 1.30 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-5,39	0,99	
		Burst: Injection down casing	0,7	1,4	1,1	Closed WH pressure @ 345 bar + 1.10 sg kill mud	Fluid gradient w/pore pressure	0,98	NA	-5,39	1,1	
						Closed WH pressure @ 301 bar + 1.10 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-5,39	1,34	
						Closed WH pressure @ 345 bar + 0.84 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-5,39	1,34	
			0,5	1,3	1,0	Closed WH pressure @ 345 bar + 1.00 sg kill mud	Fluid gradient w/pore pressure	0,66	NA	-6,3	1	

Collapse Loads after Installation		Collpase: N/A				Closed WH pressure @ 140 bar + 1.00 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-6,3	1,55	
						Closed WH pressure @ 345 bar + 0.4sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-6,3	1,57	
			0,3	0,8	1,2	Closed WH pressure @ 345 bar + 0.8 sg kill mud	Fluid gradient w/pore pressure	0,82	NA	-7,09	0,86	
						Closed WH pressure @ 225 bar + 0.8 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-7,09	1,15	
						Closed WH pressure @ 345 bar + 0.55 sg kill mud	Fluid gradient w/pore pressure	1,10	NA	-7,09	1,15	
	Lost circulation while drilling	Axial: - Static load condition post cementing operation Burst: N/A	1,1	1,9	1,3	Mud drop level = 686 m with a pore pressure EMW of 1.058 sg and 1.30 sg OBM	Fluid gradient w/pore pressure	NA	2,07	-7,31	1,39	• Lost return depth 5450mMD
			0,9	1,5	1,3	Mud drop level = 682 m with 1.30 sg OBM	Fluid gradient w/pore pressure	NA	1,35	-5,39	2,61	
			0,7	1,4	1,1	Mud drop level = 748 m with a pore pressure EMW of 0.877 sg and 1.10 sg OBM	Fluid gradient w/pore pressure	NA	3,4	-5,39	3,74	
			0,5	1,3	1,0	Mud drop level = 140,05 m with a pore pressure EMW of 1.058 sg and 1.00 sg OBM	Fluid gradient w/pore pressure	NA	4,76	2,26	1,42	

	Collapse: - Lost circulation with mud drop	0,3	0,8	1,2	Mud drop level = 0 m with a pore pressure EMW of 1.058 sg and 0.8 sg OBM	Fluid gradient w/pore pressure	NA	-	-	-	
Pressures Above/Below Packer worst during operation	**Axial:** - Static load condition post cementing operation	1,1	1,9	1,3	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	2,35	-7,31	7,41	• Fluid drop may occur due to the hydrostatic head of the fluid equilibrating with the depleted pressure at the perforations. Fully evacuated casing below packer to gas gradient.
		0,9	1,5	1,3	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	3,02	-5,39	4	
	Burst: N/A	0,7	1,4	1,1	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	3,26	-5,39	10,37	
		0,5	1,3	1,0	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	3,58	2,26	1,42	
	Collpase: -Above/Below Packer	0,3	0,8	1,2	Fully evacuated to a PP of 1.05 sg	Fluid gradient w/pore pressure	NA	-	-	-	

(blue)	Resulting in minimum safety factor for all of the service life load condition, SF higher than BP Skarv design factor
(red)	Safety factor higher than minimum required safety factor for all of the service life load conditions
(yellow)	SF lower than minimum required
(green)	Compression
(grey)	Not applicable for the load case

APPENDIX 8: SKARV PRESSURE ESTIMATION PLOT