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Slender well drilling and completion

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Utfyllende tekst/Extended text:

Background:

Offshore wells being constructed today have large well volume and are being drilled with large, high cost drilling units. There is an important potential for cost reduction through starting the well with a substantially smaller diameter, which will imply reduced casing dimensions and cost, reduced mud volumes and cost, reduced BOP size and cost, and the possibility to use lower cost drilling units. The cost reduction potential is highest for subsea wells. The project objective is to develop a 15000 psi Slender Subsea Well (SSW) concept based on enabling technologies. One key element in slender well design is casing/ liner design and hydraulic program.

Tasks:

1) Present alternative slender well designs for exploration drilling and production drilling.
2) Perform casing/liner design for a typical subsea well
3) Perform ECD calculations and suggest alternative designs or solution (alternative drilling methods, etc) to mitigate the problem.
4) Propose final design for a slender well and perform potential savings compared to conventional wells.

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……………………………….
Sigbjørn Sangesland

Summary

Slender well drilling is a method that drills smaller holes and is more economical than conventional drilling due to the use of smaller equipment and rigs. Using the different tools for drilling slender wells, such as expandable reamers and expandable liners means that very deep wells can be drilled. If unexpected problems such as lost circulation or over pressured zones are faced, an expandable liner can be set. This type of solution imply very little or non-loss in diameter of the section. Reducing the amount of drill cuttings, steel, mud and cement means that less storage space is needed on the rig. Less storage needs means that a smaller and lower cost rig can be used. Using smaller equipment will also reduce the risk of the operations because the equipment is easier to handle during drilling and lifting operations. Avoiding the largest hole sizes and drilling more holes in the optimum range for ROP will reduce drilling time.

There can also be some disadvantages with drilling slender wells. The equipment will be weaker if small holes are drilled, this is due to the small size of the equipment. In addition to this, hole cleaning can be a problem if mostly liners are used in the well and the well thereby have an upper sections with diameter that is significantly larger than the lower sections, since this will cause a large difference in the annular velocity of mud.

The main objective with the thesis is to investigate the potential of using slender wells for exploration and production, as well as giving an overview of slender wells and how they are drilled. The work includes well construction, casing design and hydraulic calculations. The slender well designs are then to be compared with the conventional well design by looking at material savings. Pressure data from a high pressure and high temperature (HPHT) field in the North Sea was used. One of the objectives was to design a slender exploration well for 15 000 psi pressure rating. In addition to this a slender exploration well and a slender production well were designed using a water depth of 360 m.

Based in the investigation slender well designs are feasible.

The slender exploration wells are drilled in 5 sections, using a riser with an ID of 8 5/8” and an 11” wellhead (WH) and BOP. A 20” conductor casing is set, followed by an 11 3/4” surface casing with an 8 5/8” PIL. Then a 7” liner is set, before the well is drilled through the reservoir using a 5 7/8” drill bit.

In the slender production well, an extra casing point is added to the well compared to the conventional well design, this allows more complicated wells to be drilled, or to cope with unexpected drilling problems. For drilling the slender exploration well, a riser with an ID of 12 1/2" is used together with an 11” WH and BOP. The surface casing has a diameter of 20”, followed by a 14” surface casing with a 10 3/4” PIL. An 8 5/8” liner is set below the 10 3/4" PIL. To maintain pressure integrity we install an 8 5/8 x 6 5/8” casing in the next section to isolate the liners, before the well is drilled to target depth (TD) where a 4 1/2" liner is set.

The volume of drill cuttings from drilling the slender exploration well was reduced by 61,1 % compared to the conventional well. For the slender production well, the reduction was 53,5 %. The volume of steel for casings and liners in the well was reduced by 59,1 % for the exploration well and 20,1 % for the production compared to conventional well design. The mud volume needed in the well was reduced by 53,2 % for the slender exploration well compared to the conventional well, for the slender exploration well, the reduction in mud volume was 45,2 %.

Further focus should be on well completion equipment for 15K pressure rating. This include expandable liner hanger, wellhead, BOP etc. A comparison of equipment for 10K versus 15K would have been of interest. Another important aspect is the time and cost saving from drilling slender wells.

Sammendrag

Boring av slanke brønner med mindre diameter er kostnadsbesparende fordi det brukes utstyr som er mindre, og størrelsen på riggen kan reduseres. Ved å bruke de forskjellige redskapene for boring av slanke brønner som ekspanderende borekroner og ekspanderende linere kan veldig dype brønner bores. Om vi støter på uventede problemer under boring som f.eks. tap av borevæske eller høytrykkssoner kan vi sette en ekspanderende liner som vil gi veldig lite eller ingen tap av diameter. Ved å redusere volumet av borekaks, stål, borevæske og sement oppnår vi et redusert behov for lagringsplass på riggen. Dermed kan en mindre og billigere rigg med mindre lagringsplass brukes. Bruken av utstyr som er mindre og lettere å håndtere gjør at bruk og flytting/transport av dette utstyret blir mye sikrere og flere ulykker og skader blir unngått. Ved boring av slanke brønner unngår vi de aller største seksjonene som vanligvis er i toppen av en brønn, dette betyr at borehastigheten blir høyere og tiden for boring blir dermed redusert.

Det kan også være ulemper ved å bore slanke brønner, hvis hullene som er boret er små vil utstyret som brukes være mindre og svakere. Hullrensing kan være et problem hvis mange linere er brukt i brønnen siden disse vil forårsake at de øverste seksjonene er my større enn de nederste seksjonene, og dermed vil det bli en stor differanse i slamhastigheten.

Hovedformålet med denne oppgaven er å undersøke potensialet av å bore slanke lete- og produksjonsbrønner, samt å gi en innføring i hva slanke brønner er, og hvordan disse bores. Dette inkluderer å gjøre fôringsrørdesign og hydrauliske kalkulasjoner. Etter å ha designet de slanke brønnene, har de blitt sammenlignet med det konvensjonelle designet. Trykkdata fra et HPHT felt i Nordsjøen har blitt brukt for å designe brønnene. Et av formålene med oppgaven var å designe en slank letebrønn som tåler et trykk på 15 000 psi. I tillegg til denne, ble to andre brønner designet; en slank letebrønn og en slank produksjonsbrønn, alle brønnene med et vanndyp på 360m.

Etter å ha gjort fôringsrørdesign og trykkfallkalkulasjoner ser det ut til at det er mulig å gjennomføre disse brønnene.

De slanke letebrønnene er boret i 5 seksjoner, og et stigerør med en innvendig diameter på 8 5/8” er brukt sammen med brønnhode og BOP med en diameter på 11”. Et fôringsrør med en diameter på 20” er satt øverst i brønnen, etterfulgt av et 11 3/4” fôringsrør med en 8 5/8” forhåndsinstallert liner. En 7” liner er så satt før brønnen bores gjennom reservoaret med en hullstørrelse på 5 7/8”.

I den slanke produksjonsbrønnen er det sammenlignet med det konvensjonelle designet introdusert et ekstra fôringsrørpunkt, dette hjelper oss med å bore vanskelige brønner, og å løse uventede problemer vi kan støte på under boringen. For å bore den slanke produksjonsbrønnen blir det brukt et stigerør med en innvendig diameter på 12 1/2” sammen med brønnhode og BOP som er 11”. Det første fôringsrøret som er satt har en

diameter på 20” og blir etterfulgt av et 14” fôringsrør med en forhåndsinstallert liner med en diameter på 10 3/4”. En 8 5/8” liner blir så satt under 10 3/4” fôringsrøret. For å opprettholde en trygg brønndesign ønsker vi å isolere linerene ved å sette et fôringsrør som går helt opp til overflaten i den neste seksjonen, dette fôringsrøret har en diameter på 8 5/8 x 6 5/8”. Brønnen blir så boret til endelig dybde hvor en liner med en diameter på 4 1/2” blir satt.

Om vi sammenligner volumet av borekaks for å bore den slanke letebrønnen opp mot å bore den konvensjonelle brønnen så ser vi at ved å bore den slanke brønnen oppnår vi en reduksjon av borekaksvolumet på 61,1 %. Når det gjelder den slake produksjonsbrønnen så er denne reduksjonen på 53,3 %. Stålvolumet som trengs for fôringsrør og linere i brønnen ble redusert med 59,1 % for letebrønnen og 20,1 % for produksjonsbrønnen sammenlignet med den konvensjonelle brønnen. Borevæskevolumet som trengs for å bore brønnene ble redusert med 53,2 % for boring av den slanke letebrønnen sammenlignet med den konvensjonelle brønnen. For den slanke produksjonsbrønnen er dette tallet 45,2 %.

Videre fokus bør være på utstyret som blir brukt og å finne utstyr som kan tåle 15 000 psi, dette inkluderer ekspanderende liner-hengere, brønnhoder, BOP etc. En sammenligning av utstyr som tåler 15K opp mot utsyr som tåler 10K hadde også vært av interesse. Et annet veldig viktig aspekt ved å bore slanke brønner er å finne ut hvor mye penger og tid som kan spares ved å velge en slank brønn.

Acknowledgements

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Nomenclature

APB – Annular pressure build up

BHA – Bottom hole assembly

BOP – Blow out preventer

DHSV – Down hole safety valve

DP – Drill pipe

DC – Drill collar

ECD – Equivalent circulating density

HPHT – High pressure and high temperature

HSE – Health Safety and Environment

ID – Inner diameter

MPD – Managed pressure drilling

MW – Mud weight

MWD – Measurement while drilling

OD – Outer diameter

PIL – Pre-installed liner

RKB – Rotary Kelly bushing

ROP – Rate of penetration

s.g. – Specific gravity

SF – Safety factor

TD – Target depth

UR – Under reamer

WH - Wellhead

1. Introduction

The oil industry is always seeking new technology to drill more efficient and cost effective. The cost of drilling a well is very high due to the cost of equipment and the day rate of hiring a drilling rig. We can say that the oil companies want to drill the wells as small as possible, but as large as necessary. The transportation can be challenging where there are remote locations that are expensive to reach, because the transportation will be time consuming and expensive. Slender well technology is a method that can significantly reduce the cost of equipment and transportation. When slimming down the well it is desired to maintain the diameter of the productive section, but slim down the remaining of the well. This will give a well design with closer clearances between the casing strings. To be able to design such wells new technology is needed. New technologies such as expandable liners, close clearance liners, bi-centre bits and near bit reamers are tools that can help the industry to reach this goal.

In some wells unexpected problems are faced such as lost circulation and over pressured zones. With a conventional drilling program these unexpected problems might lead to plugging, abandonment or side-tracking of the well because the final section will be too small if additional casing strings are set. The goal if unexpected problems are faced is to be able to continue drilling without losing any or too much hole size. Slender well technology ensures that the well can be drilled further and all the way down to the target depth. And even if the well is lost, slender well drilling allows 2 – 3 wells to be drilled for the cost of one single conventional well (Strand 1994).

Some reservoirs could be impossible to reach with conventional drilling and conventional drilling programs due to difficult pressure regimes in the well. New technology has to be used to be able to reach reservoirs that are hard to reach. Slender well drilling ensures that there is theoretically no limitation of how deep a well can be drilled regarding casing design, even if unexpected problems are faced. However there can be problems with torque, drag and friction losses when the well becomes too long.

HSE is always a highly focused area in the oil industry, the goal is to have zero incidents and this is taken very seriously. Using smaller equipment which makes the handling and lifting operations safer is a huge step in the right direction. The environment is something that is focused more and more upon, and the goal for the companies is to be as environment friendly as possible. To be more environment friendly, the companies have to find new technology that reduces pollution from CO_2 etc. One way to achieve this goal is to use rigs that pollutes less, and drilling holes that requires less mud, steel and cement. Also the pollution from transportation should be reduced to a minimum.

2. Slender well drilling

When drilling we want to drill as large as necessary but as small and cheap as possible. This chapter will present slender well drilling, which basically is drilling smaller diameter holes, with it benefits and disadvantages. In addition to this, also the tools and techniques used for drilling slender wells are presented. Drilling smaller holes and using a smaller diameter riser will save a lot of money and storage space on the rig, leading to the opportunity of using a smaller and cheaper rig. The BOP will also be a smaller, meaning that it will require less deck space and will be a lot lighter and easier to handle than the BOP's used for conventional drilling. An 11" BOP will weigh only 1/3 of the conventional 18 3/4" BOP (Strand 1994). Strand 1994 has studied slender well drilling and equipment used for drilling slender wells. In the report, they studied the wellhead sizes for slender wells and came to the conclusion that an 11" wellhead is the best solution for the use in a slender well, while the size of a conventional wellhead is 18 3/4". A 13 5/8" wellhead was also considered but the advantages of the 11" wellhead makes the 11" wellhead the best choice since it has among other benefits:

- Lower cost
- Better circulating conditions in the riser
- Lower riser tensioning requirement
- Smaller size and weight

Using a larger wellhead will however give improved flexibility in the well design and improved intervention service opportunities.

Strand 1994 found that the 11", three hanger wellhead and BOP can be pressure rated to 15 000 psi. A wellhead is shown in figure 2.1. The maximum casing size that can be set inside the 11" housing is 8 5/8".

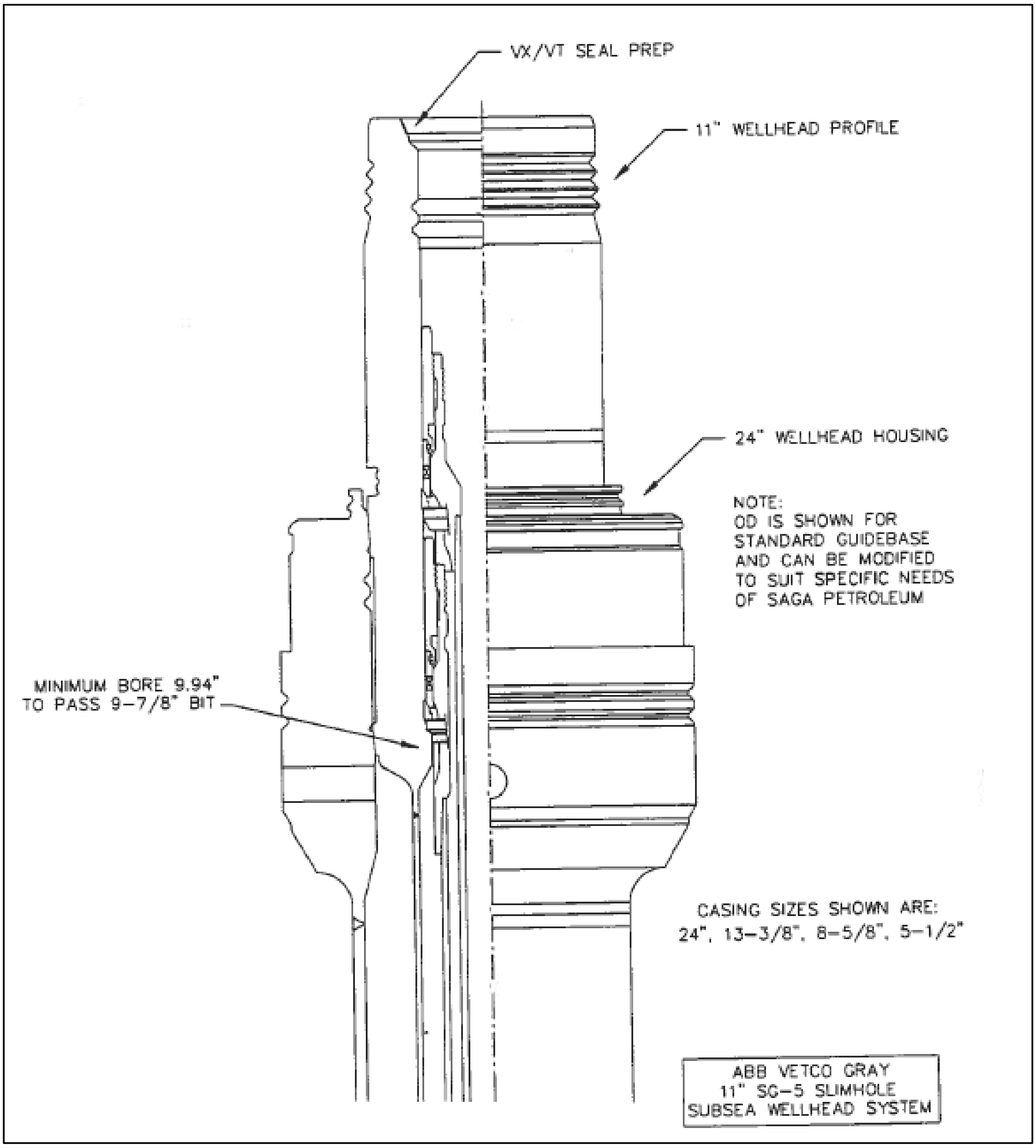

Figure 2.1: 11" Wellhead with a pressure rating of 15 000 psi (Strand 1994).

2.1 Advantages from drilling slender wells

Drilling slender wells reduces the size of the holes drilled, especially the top holes are significantly reduced. There are several advantages by reducing the holes that are drilled. The most important keywords for the advantages are (Howlett et al. 2006):

- Economically
- Environmental
- Reduced risk
- Contingency
- Abandonment

By using slender well technology the wells are drilled more *economically* because the holes drilled are smaller. This means that less mud, steel and cement is needed for drilling a well, in addition there will also be generated less drill cuttings from drilling the well. The cement volume of a slender well is about 1/5 the volume of a conventional well (Strand 1994). All these savings leads to the use of a smaller rig since less storage space is needed, and the equipment is easier to handle. The rig cost is an important aspect in the cost of drilling a well, since the day rate of hiring a rig is high. Slender well drilling also is time saving, because the ROP is higher since more holes are drilled in the optimum sizes for ROP when the largest hole sizes are avoided. This is shown in figure 2.2, we see that the "sweet spot" for drilling is ranging from about 6" and up to about 12 1/4".

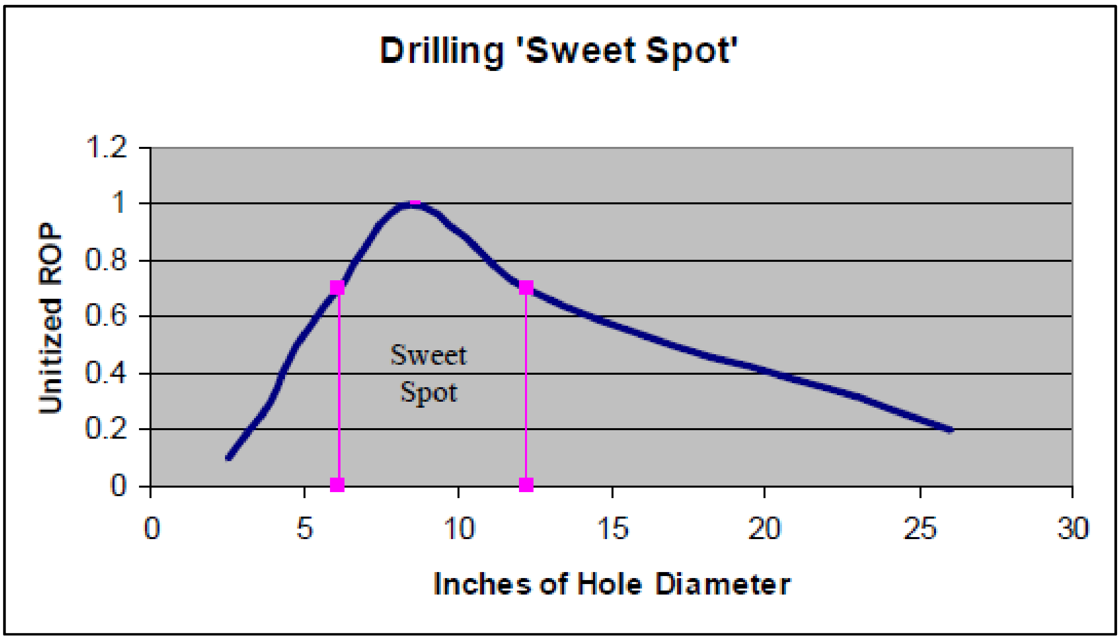

Figure 2.2: Unitized ROP vs. size (Demong et al. 2003).

The *environmental* aspect is due to the reduction in CO_2 from transportation, steel production, reduction in the use of mud and cement, and the reduction in emissions from the rig itself if a smaller rig is used.

The *reduced risk* of drilling a well is mainly because of the use of smaller equipment which is easier to handle because it is smaller and lighter. This makes the lifting operations safer, and the handling regarding transportation will also be safer.

If unexpected problems are faced, the *contingency* is better because additional liners can be set without losing little/any hole size. Unexpected problems could be such as lost circulation or over pressured zones, which forces the operator to stop drilling and set an additional casing/liner.

The *abandonment* is simplified because mostly liners are used instead of casing strings. If regular casing strings are used, there will be migration paths between the casings which are potential leak paths. The use of liners means that there are no such migration paths between the liners, and thereby the abandonment is simplified and has less risk.

2.2 Disadvantages from drilling slender wells

There are certain disadvantages with drilling slender wells, especially if the sections are drilled with a smaller diameter than what is normal for a conventional well where the smallest hole size normally is 8 ½”. If the sections drilled are smaller, there can be problems with pressure loss, since the annulus between the drill pipe and the casing/OH will be small. Another problem is hole cleaning, which is due to the fact that using liners leads to that the upper sections have a lot larger diameter than the lower sections. This leads to a big difference in the muds annular velocity. To maintain a high enough flow rate in the upper sections, the annular velocity in the lower sections have to be very high, but then the frictional pressure loss will be too high for the mud pumps to handle. This problem can be avoided by using tie-backs, which are an extension of the liner that goes all the way up to the seabed. Figure 2.3 show a well before and after the installation of a tie-back string, we see that after the tie-back is installed the well has the same diameter all the way up to the surface. The advantage by using a tie back is that it will eliminate the problem with too large annular area in the upper sections, and the well can thereby be circulated with a lower flow rate. Setting a tie-back will also make the pressure integrity of the well safer because there will be an additional barrier. However using a tie back string requires additional steel that raises the cost of the well, and more time is required for installing the tie back.

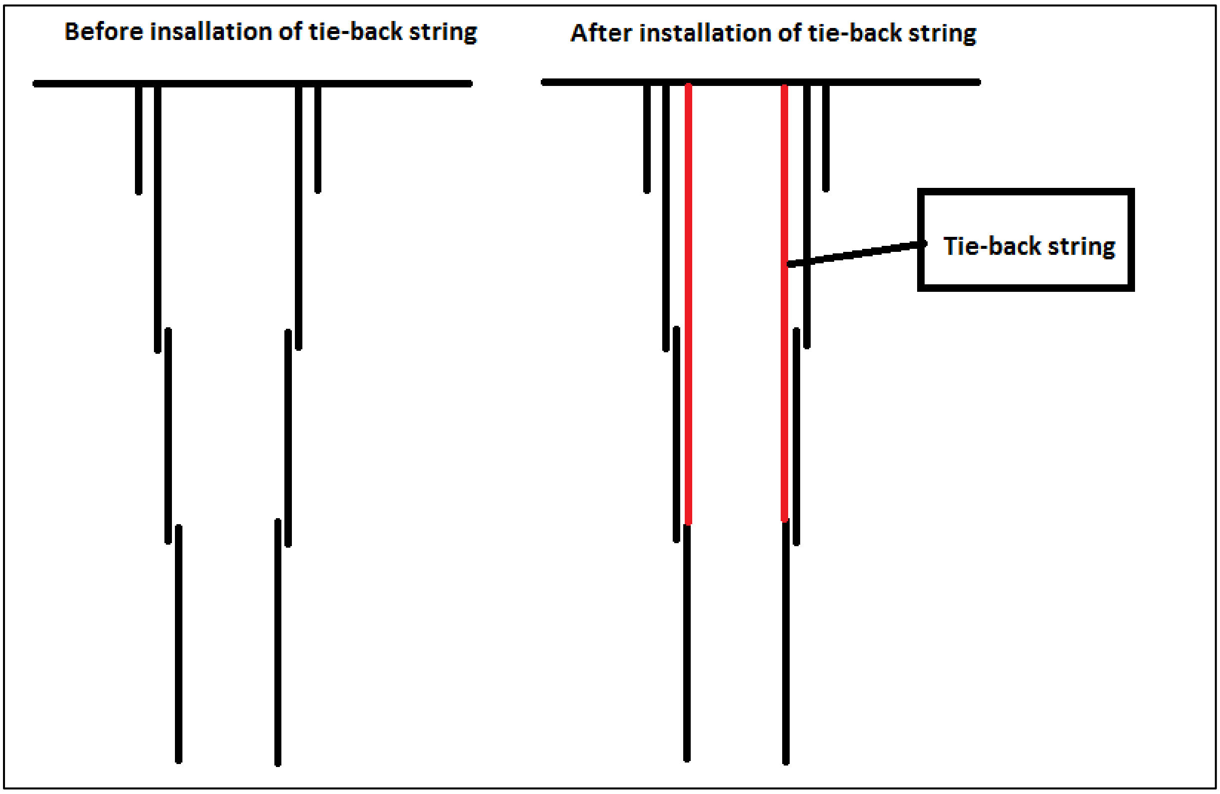

Figure 2.3: Before and after installation of tie-back string.

The equipment used for drilling a well will logically be more fragile the smaller it is. A small diameter drill string will be a lot weaker than a large diameter drill string. Generally it can be said that hole sizes below 7 7/8" are more challenging to drill, because of the small BHA parts that are used in small holes (DeMong 2003). The parts will be less durable and more flexible, this can lead to drag and buckling problems. Moving parts like roller cone bits and other down hole tools that are moving can have problems due to heating up, which again will lead to reduced lifetime for the parts.

2.3 Slim riser

Reducing the size of the riser is an important part of drilling slender wells. Normally the two first sections of a well is drilled riser less, and the riser is then connected before drilling the third section. When the riser is connected, the size of the riser gives limitations of the size of the bit used to drill the next section since the bit has to be small enough to be able to fit inside the riser. The riser will also give limitations of the casings, liners and casing hangers that are installed because everything has to be able to pass through the riser.

The conventional riser used has an outer diameter of 21” and an inner diameter of 19”, by reducing this diameter there are several advantages that saves money and time:

- Requires less deck space
- Less mud is needed to fill the riser due to its smaller volume
- Increased annular mud velocity inside the riser
- Reduced tensioner load
- Easier to handle

Reducing the size of the riser from 21” and down to 16” will save (Childers et al. 2004):

- 40 – 45 % less storage space per joint.
- The weight is only 70 – 75 % of the conventional riser including buoyancy.
- The mud volume is 55 – 60 % of the conventional riser.

By reducing the size of the riser even more, the savings will be a lot larger. In the examples we will be looking at the size of the smallest riser is only 8 5/8” for the exploration wells and 12 1/2" for the production well. Compared to the conventional 21” riser, the volume of mud in the riser is reduced by 56,7 % for the 12 1/2" riser and 79,4 % for the 8 5/8” riser. This is a quite significantly reduction, which will save a lot of mud, depending on the length of the riser.

The reduced loads and storage requirements contributes to a huge step on the way to using a smaller rig which is a lot cheaper to hire.

2.4 Pre-installed liner

A pre-installed liner (PIL) is a liner that has one more liner inside of it when it is run in hole, figure 2.4 show the liner before and after installation. Between “as run” and “installed”, the next hole section where the PIL is installed is drilled. The benefit of using a pre-installed liner is that a smaller diameter riser and BOP can be used, and still the diameter of the third section, which is the first section that is drilled with a riser, will not have to be reduced to be smaller than the riser. This is done running a pre-installed liner inside the surface casing before the riser and BOP is connected. To be able to drill the section where the pre-installed liner is going to be put in place, the section has to be drilled with an expandable reamer or bi-centre bit, this is for the bit to be able to pass through the riser and BOP. Since the liner is installed and run inside the previous casing, the PIL cannot be longer than the casing it is run inside, this is a limitation of using a PIL.

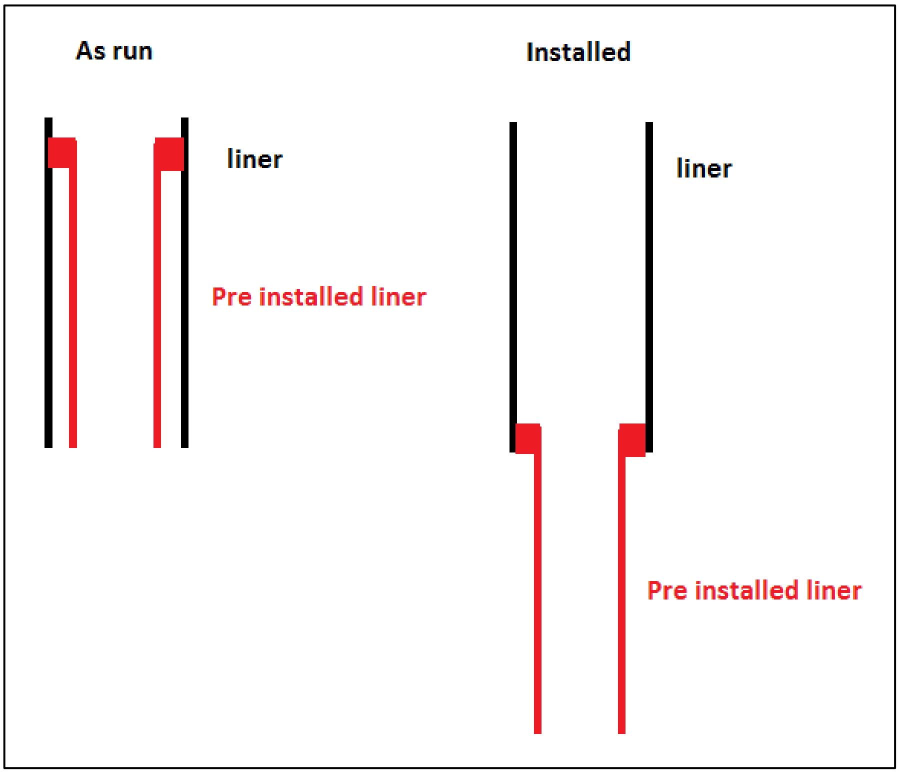

Figure 2.4: Pre-installed liner as run, and after installation.

2.5 Expandable liner hanger

In difficult hole sections it could be an advantage to rotate the liner to get it in place. If conventional liners are rotated, there will be danger of setting the liner or releasing the setting tool, this will not be a problem using an expandable liner hanger.

Expandable liner hangers have several advantages, the reduction in hole size where the liner hanger is located will be less than for conventional liner hangers because the liner hanger is expanded to make a metal to metal seal between the liner hanger and the liner.

Using expandable liner hangers have large benefits compared to using conventional liner hangers, some of them are listed below (Lee Lohoefer et al. 2000):

- The liner can be rotated or reciprocated to assist the liner in reaching the target depth.
- There is less chance of mechanical failure than for conventional liner hangers.
- The running tool is very reliable.
- Since there is a metal to metal seal, the dependence of cement is reduced due that the liner and liner hanger are sealed when it is expanded.
- Easier to get a good cement job since the liner can be rotated during pumping of cement.
- Simple design compared to conventional liner hangers.

The expandable hanger joint has several bands of elastomeric material that are coated to the joint. When the liner is expanded the elastomer provides the primary anchoring force for the hanger and attached liner. The hanger also has ribs that separate the bands, these ribs works as a secondary anchoring force. The elastomer and the ribs are shown in Figure 2.5, which show the liner before and after the expansion. A single one-foot elastomer section on the 7 5/8 x 9 5/8" liner hanger is capable of supporting over 450 000 lbf of hang weight (Williford et al. 2007).

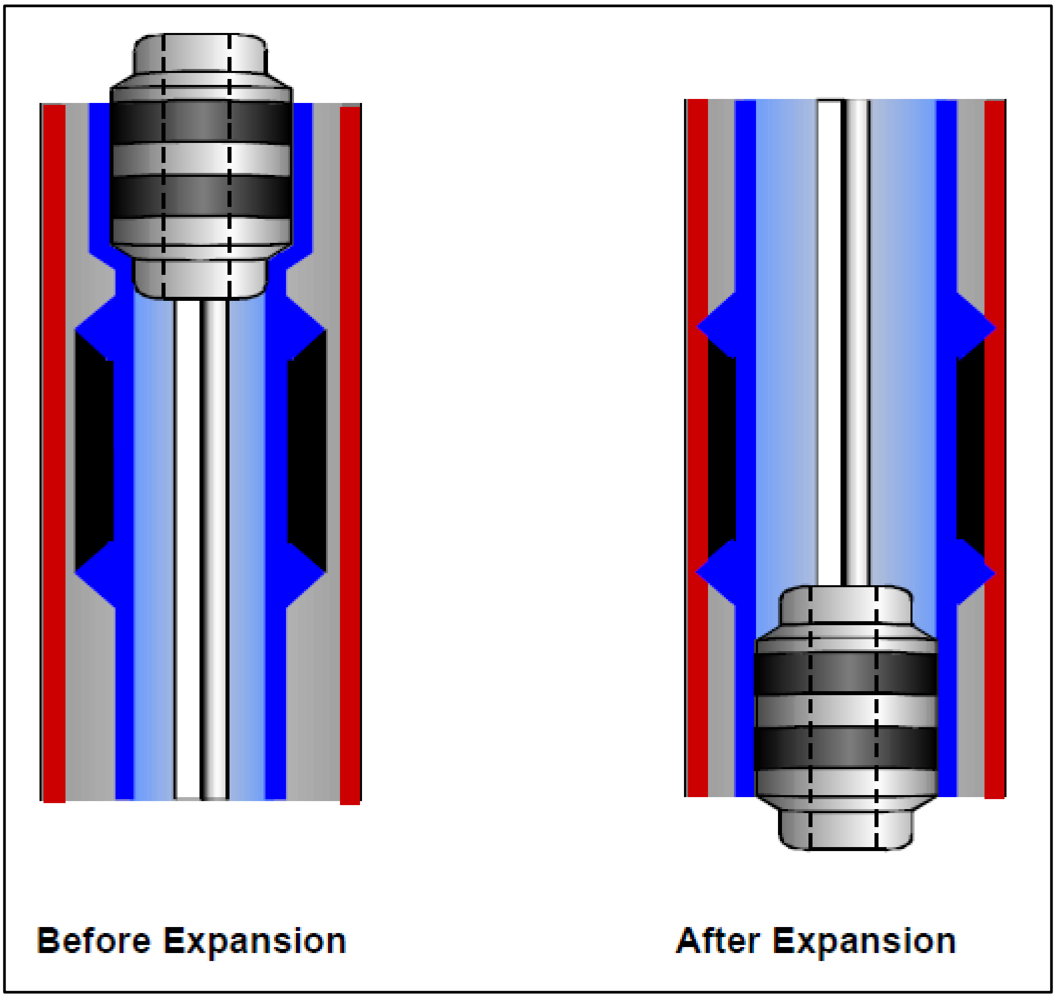

Figure 2.5: Before and after expansion of the liner (Lee Lohoefer et al. 2000).

The expansion process is shown in Figure 2.6. First the hole is drilled and the liner is put in place. After the liner is put in place, cement is pumped through the liner and out into the annulus outside of the liner. Then the liner hanger is expanded top-down using a running tool, and the running tool is thereafter retrieved to surface and the shoe can be drilled out.

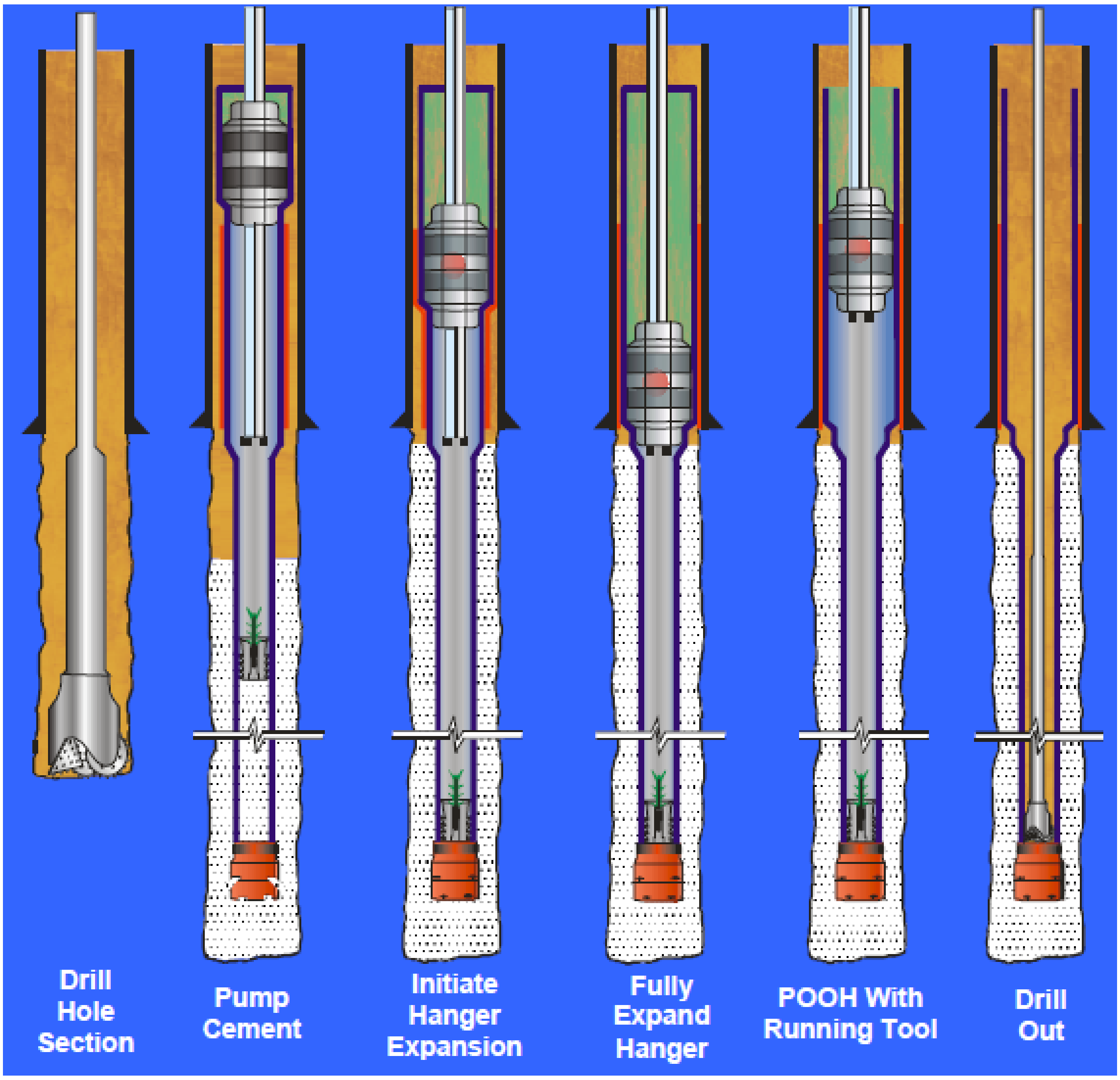

Figure 2.6: Expansion process using expandable liner hanger technology (Lee Lohoefer et al. 2000).

TIW XPAK liner hanger system is an expandable liner hanger system that is excellent for close clearance operations. The liner hanger has been a weak spot in designing slender wells, since the pressure rating of the liner hangers has been below the pressure rating of the liner itself. The TIW XPAK liner hanger has a high pressure integrity that is claimed to be equal to the pressure integrity of the liner itself. An expander mandrel is left in place inside the liner hanger after expansion, this provides full support across the expanded tube and eliminates the low collapse rating which is a problem using other expandable systems. The expanded section is relatively short, ranging from 16 to 24 inches, but still the hanger will not be a weak spot (TIW Corporation 2010). The expander and hanger are presented in figure 2.7. The liner hanger before and after expansion are shown in figure 2.8.

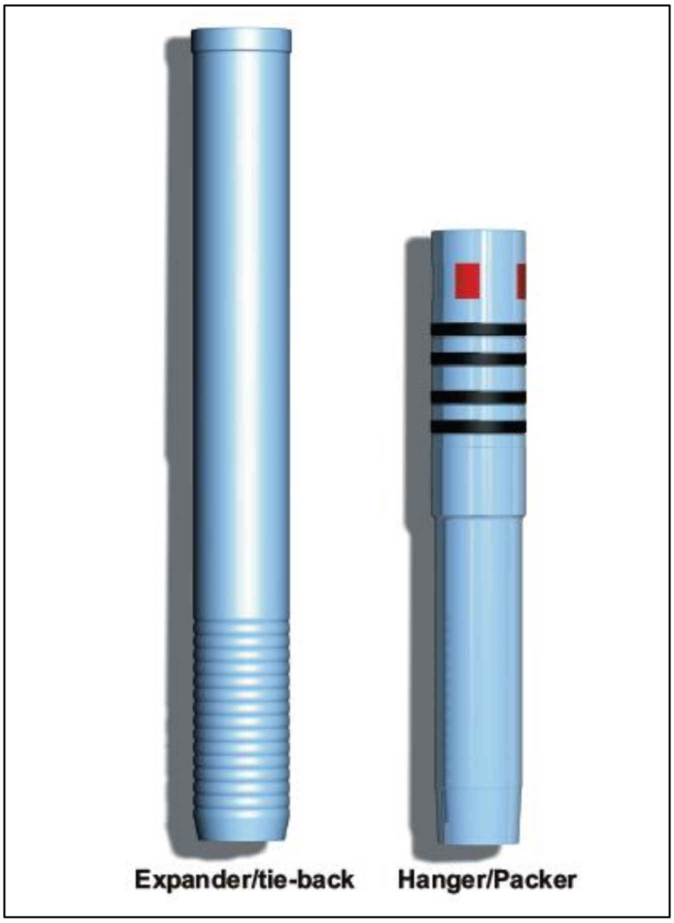

Figure 2.7: TIW expander/tie-back and hanger/packer (TIW Corporation 2010).

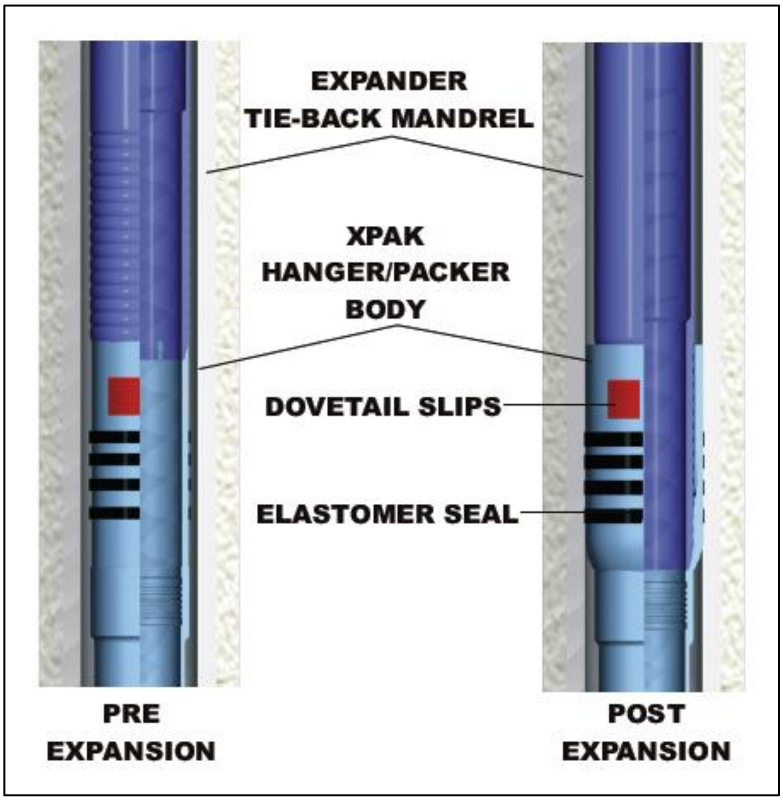

Figure 2.8: TIW expandable liner hanger before and after expansion (TIW Corporation 2010).

2.6 Expandable liners

Expandable liner strings are used to expand the liner after it is put in place down hole, to a diameter that would have been impossible to get down through the previous casing. By using a casing string with a smaller diameter while running in hole, and expanding the string when it is in place. If an expandable liner is used, the well will not lose as much of its size, and thereby the next section after setting an expandable liner can be drilled with a larger diameter than if a conventional liner is set.

The hole section is first drilled to target depth, then the expandable liner joints are screwed together till the required length of the liner is reached. There are different techniques to expand the liner, some companies deliver a system that uses top-down expansion, while others uses a bottom-up technique.

Eventure is the leading company when it comes to expandable liners (Shen 2007), they use a bottom-up expansion by using an expansion cone. After the hole section has been drilled, the expansion cone is placed at the bottom of the expandable liner, and the liner joints are screwed together while running in hole until the required liner length is achieved. When the liner has the required length, it is hung in the rotary table, and the drill string is run inside the liner and latched into the expansion cone, the drill string is then used to get the liner down to target depth. When the liner is in place it is first cemented, the cement is pumped down through the drill string. A latch-down plug is dropped right after the cement is pumped, when this plug reaches the bottom of the string it creates a pressure chamber below the expansion cone. Now hydraulic fluid can be pumped down to start the expansion process, the fluid pumped creates pressure that forces the expansion cone upwards, and the liner is expanded at a rate of 20-30 feet per minute. After the expansion is finished, the cone is retrieved to surface. After retrieving the expansion cone, the next section can be drilled by first drilling out the casing shoe. The process is shown in Figure 2.9.

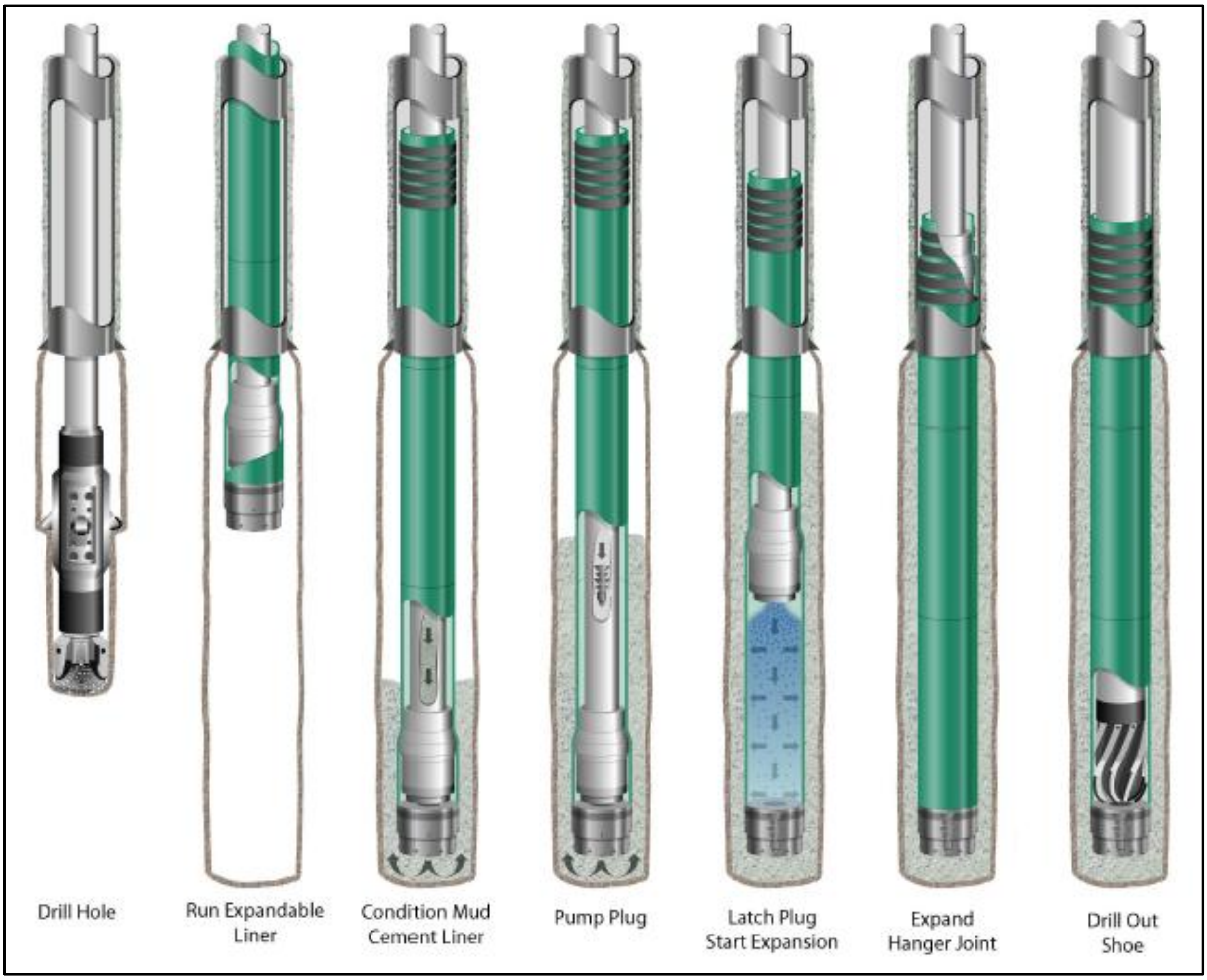

Figure 2.9: Expansion process, bottom-up (DeMong et al. 2003).

There are also some solutions where the expansion process takes place top-down, the liner is first positioned at the desired depth down hole and expanded top-down using a hydraulic mechanical system. A tapered shaped cone is used to expand the liner, the cone is pushed down through the liner using a hydraulic piston and anchor combination. The pressure that is applied to the drill pipe fluid is translated to mechanical linear force via a down hole piston attached to the expansion cone. A hydraulic anchor that is activated when hydraulic pressure is applied to the drill pipe secures the top section of the piston to the surrounding casing and thereby prevents up hole movement of the drill pipe when the piston is moving the cone downwards. When the piston is completely stroked the pressure is released from the system that holds the anchor, so the tool can move freely in the wellbore. The piston is then closed and the tool is reset by moving the whole drill pipe with the tool downwards. Pressure is then again applied to the system and the expansion process is repeated until the whole liner is expanded. The whole process is described in Figure 2.10.

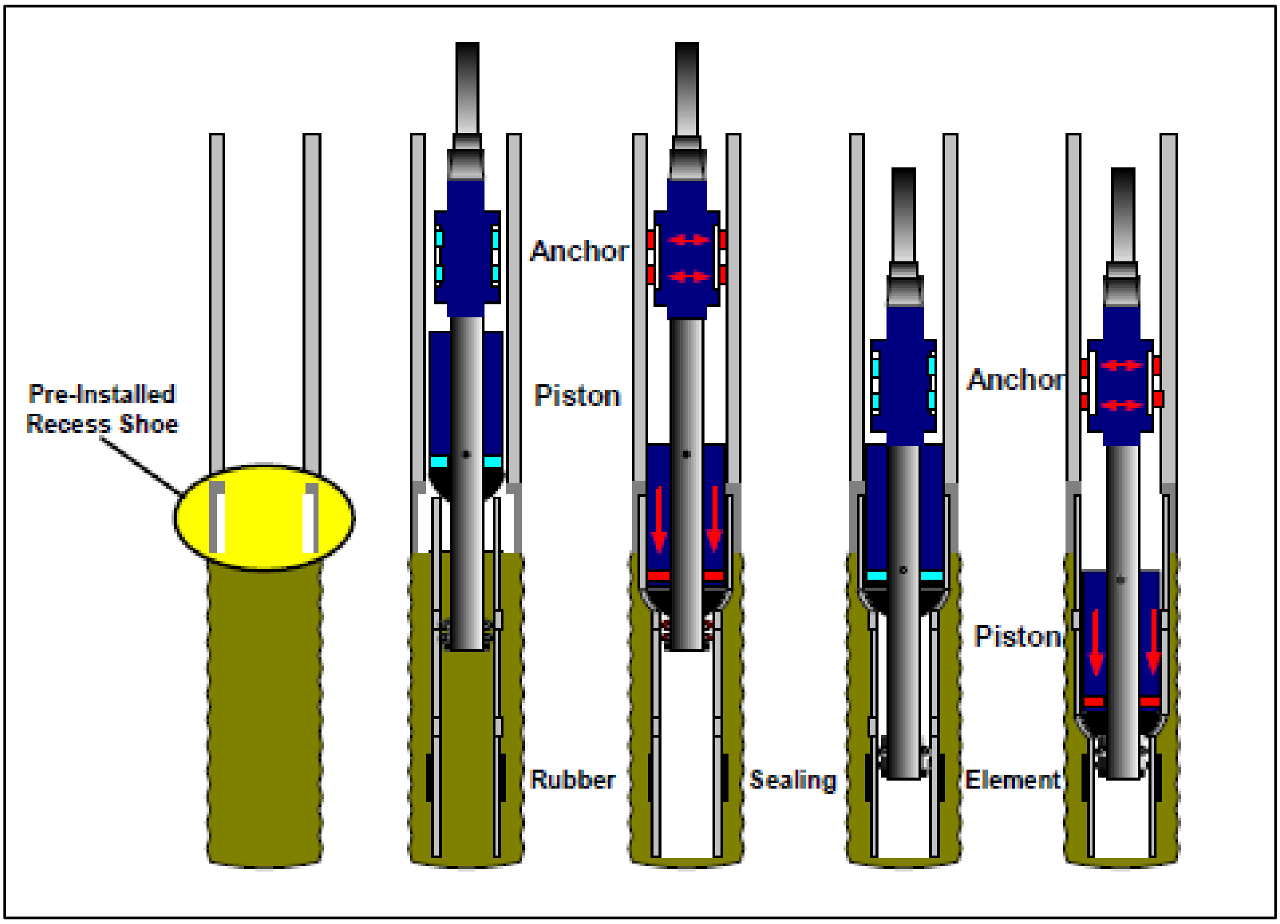

Figure 2.10: Top-down expansion process (Jabs 2004).

2.6.1 Expansion of steel

To be able to expand the liners, the following capabilities are required (Steward et al. 1999):

- The tubular have to be expanded without fracturing, bursting or damaging the tubular.
- The hydraulic capabilities have to be maintained, so that it provides sufficient resistance to burst and collapse loads.
- A constant diameter and wall thickness is required over the whole expanded length.
- The integrity of expanding tubular connections has to be maintained.
- It is desired to be able to expand long sections at high rates.

The first part of the expansion of steel is the elastic deformation, and the second part of the expansion is the plastic deformation. This is shown in figure 2.11, where the stress-strain relationship is presented. The stress is the force applied and the strain is the deformation of the steel. If the stress-strain is increased too much, the steel will fracture, which will be critical if the liner is expanded in the wellbore.

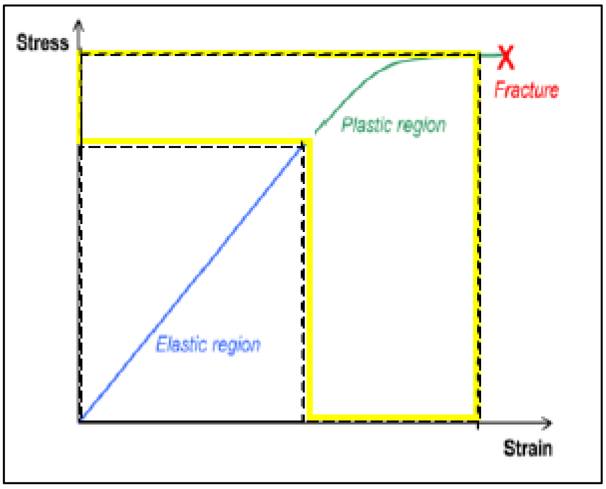

Figure 2.11: Stress-strain relationship (Shen 2007).

The elastic deformation is reversible, meaning that if the expansion force is removed, the steel will return to its original shape. After exceeding the elastic region, we move into the plastic region which is not reversible, this means that when the expansion force is removed, the steel will not go back to its original shape, but remain expanded. If we exceed the plastic region the casing will fracture.

2.7 Close clearance liners

Close clearance liners are flush jointed, and can allow for annular radial clearances as small as 1/8" in the lower reaches of the well, and 1/4" in the upper reaches of the well (Howelett et al. 2006). The use of close clearance liners, makes the loss in hole size less than for conventional liners. The most significant practical challenge is the potential swabbing and surging, because of the lack of annular flow area between the casings (Howelett et al. 2006). To prevent this, a flow diversion shoe is used, the shoe is shown in Figure 2.12. This shoe makes an artificial inner annular space, by the use of an inner tubing string and deployment tool with an internal bypass. The tool creates an inner flow area for the fluid to flow inside the liner and then over the top of the liner and around the outer diameter of the drill pipe deployment string. The effect of this tool can be seen in Figure 2.13, where we see the mud flow out of the deployment string. The artificial inner annulus makes the fluid take the path of least resistance, which will be inside the liner.

Figure 2.12: Flow diversion shoe (Howelett et al. 2006).

Figure 2.13: Effect of deployment tool (Howelett et al. 2006).

2.8 Near bit reamers

Near bit reamers, uses reamers that can expand when it passes the previous casing shoe, so that the hole section can be drilled in the same diameter as the previous section drilled. The near bit reamers can be placed anywhere in the bottom hole assembly, and expands under circulating pressure. A cut away drawing of a near bit reamer is seen in Figure 2.14, here we see the inside of the reamer, when it is not expanded.

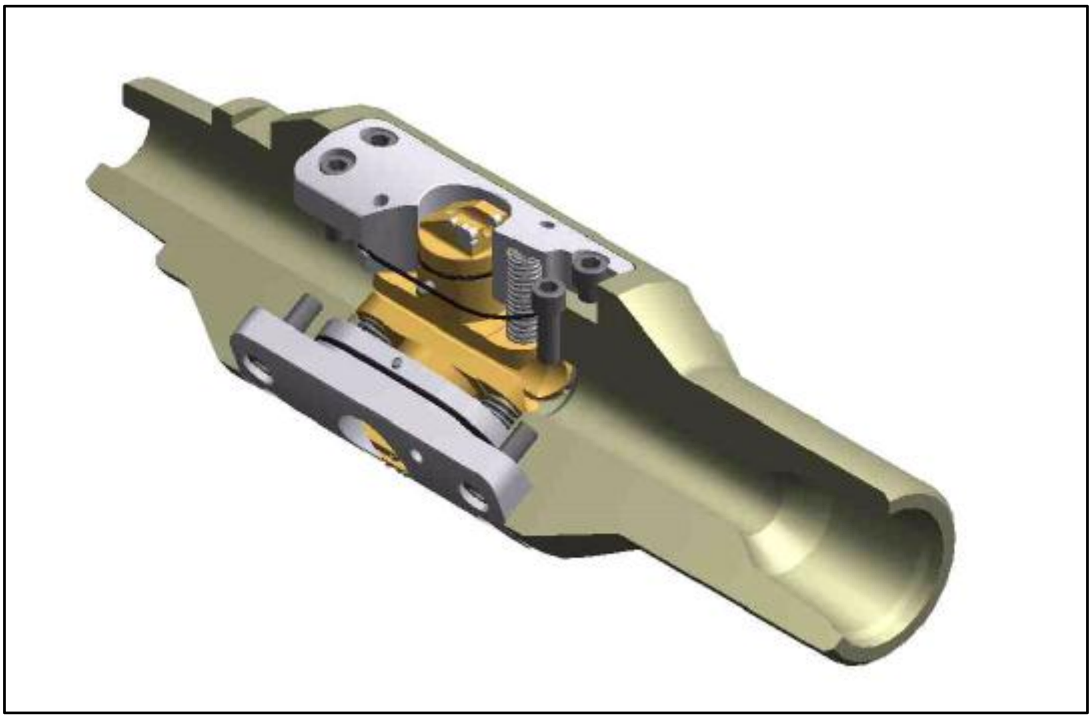

Figure 2.14: Cut away drawing of the near bit reamer, unexpanded (DeMong et al. 2003).

2.9 Bi-centre bits

Bi-centre bits can fit through the previous casing, but still drill a hole that is larger than the previous casing. It uses a bit/reamer combination consisting of a pilot bit and a reamer section, where the pilot bit drills a smaller hole and the reamer section opens the hole to the desired diameter. The pilot bit diameter of a bi-centre PDC bit is 11 – 23% smaller than the final drilled hole size (Morrison et al. 2005). The reamer is placed on only one side of the drill string, so that when it rotates it will make the hole bigger than the measured diameter of the whole tool, this is shown in Figure 2.15. In this case the pilot bit has a diameter of 6 3/4", the diameter of the reamer when not rotated is 8 1/2” but when the string is rotated it drills a hole that has the same diameter as the previous hole that was drilled, which is 9 7/8”. When tripping in the pilot bit is not in the centre of the hole, but when drilling starts the pilot bit will centre and stabilize the reamer section.

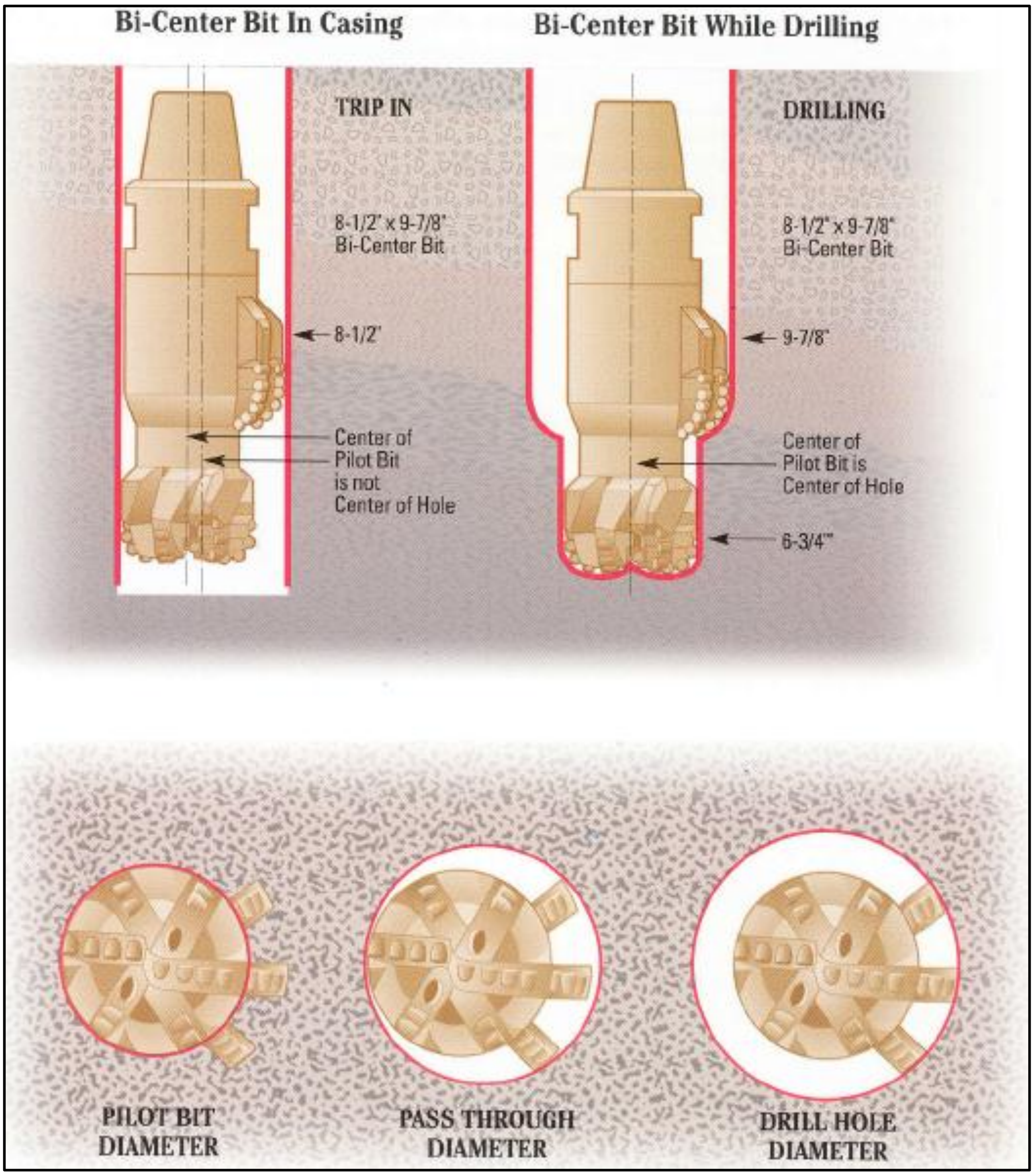

Figure 2.15: Bi-centre bit technology (Morrison et al. 2005).

3. Casing design

The casing strings in the well have to be able to withstand both burst and collapse pressures. These pressures are the differential pressure between the pressure inside the well, and the formation pressure. It is very important that the casings can withstand the worst case collapse and burst pressures, this makes the casing design important when drilling a new well. If the casing strings are too weak and break, it can cause serious problems that can be expensive and time consuming to fix.

3.1 Burst pressure

A casing may burst if the pressure inside the wellbore becomes too high compared to the formation pressure on the outside of the casing, meaning that the pressure inside the well will push the casing wall outwards, and the casing will blow as shown in figure 3.1. If the burst pressure exceeds the burst pressure rating of the casing, the casing may burst.

Figure 3.1: Burst casing (George E. King Engineering, 2009).

When calculating the worst case burst pressure for a casing string it is assumed that the worst case scenario is when the well is filled 100 % with gas while the BOP is closed. This is sketched in figure 3.2. This worst case scenario can happen if the well is taking a huge gas kick, so that high pressured gas flows into the well.

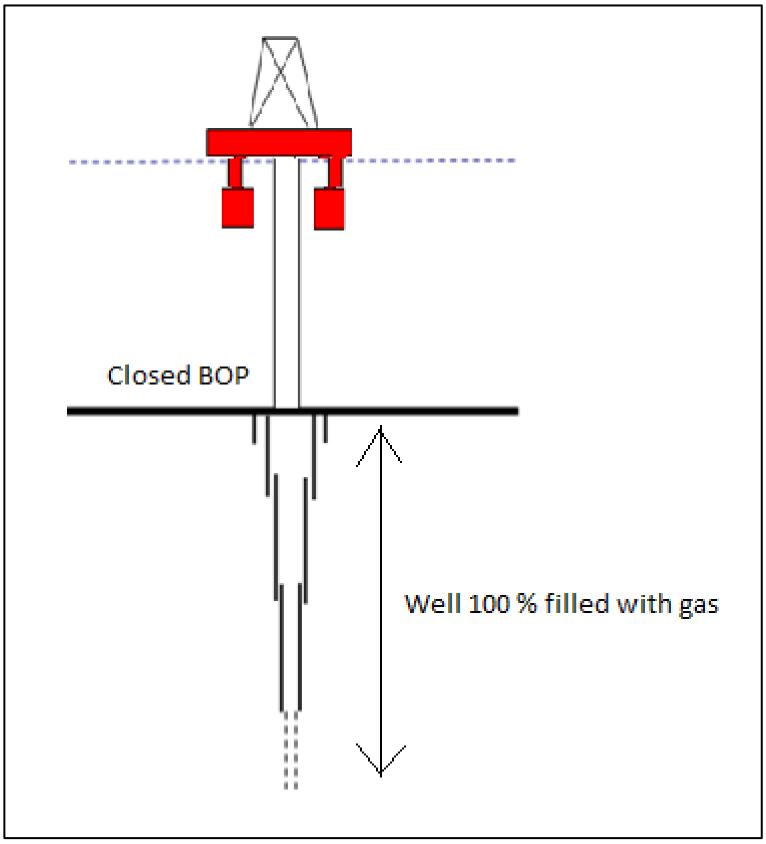

Figure 3.2: Scenario for worst case burst pressure.

Since the gas gradient will be steeper than the formation gradient, all worst case burst pressures will be calculated at the top of the casing strings since this will be where the stress is highest. This is shown in figure 3.3, we see that the differential burst pressure increases as we go further up in the well.

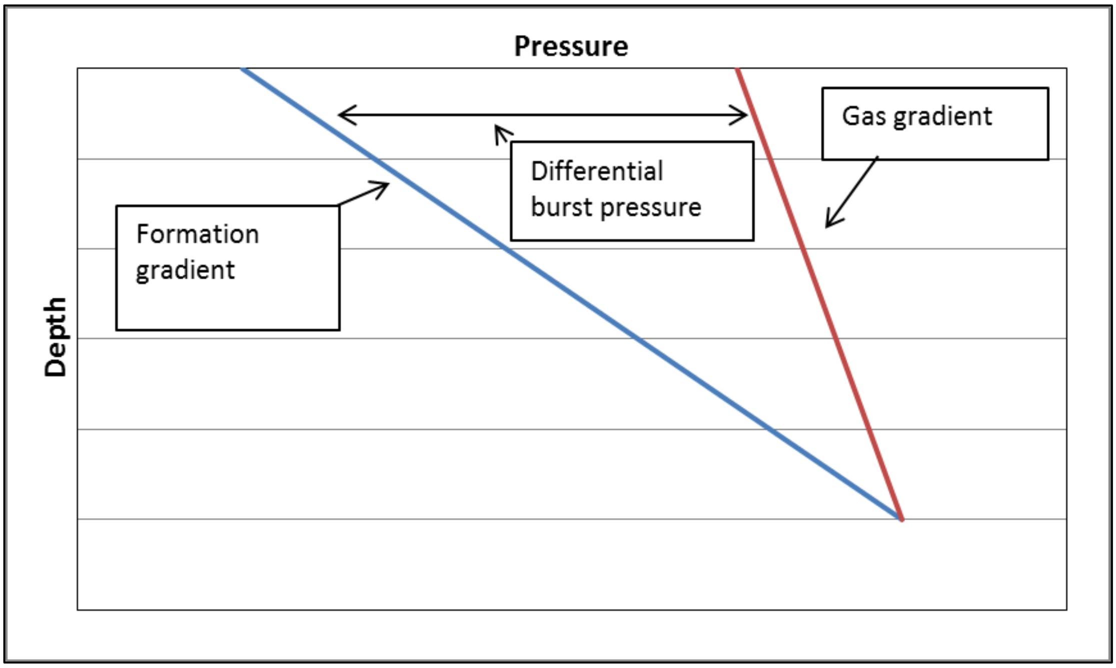

Figure 3.3: Pressure gradients for worst case burst pressure.

To be able to calculate the worst case burst pressure, we first need to calculate $P_{inside,burst}$, which is the worst case pressure inside the well for bursting the casing, this is calculated using equation 3.1.

$$P_{inside,\,burst} = P_{pore,max} - \rho_{gas} \times g \times h_{gas} \times 10^{-5} \text{ [bar]} \tag{3.1}$$

In this equation $P_{pore,max}$ is the highest predicted pore pressure in the interval the well is drilled, given in bar. ρ_{gas} is the density of the gas, which is assumed to be 230 kg/m^3, this is an ordinary gas density for gas under pressure. g is the constant of gravity which is equal to 9,81 m/s^2 and h_{gas} is the height of the gas column given in meters from the target depth of the well and up to the point where $P_{inside,burst}$ is calculated.

The differential burst pressure is now calculated using equation 3.2.

$$P_{burst} = P_{inside,burst} - P_{outside} \tag{3.2}$$

Where P_{burst} is the differential burst pressure that the casing has to withstand, $P_{inside,burst}$ is the pressure inside the wellbore and $P_{outside}$ is the formation pressure at the given depth.

3.2 Collapse pressure

A casing may collapse if the pressure inside the wellbore becomes too low compared to the formation pressure. If this happens the formation pressure can push the casing walls in towards the centre of the well, this happens since the wellbore pressure is too low to withstand the forces of the formation pressure. This is what has happened to the casing in figure 3.4.

Figure 3.4:Collapsed casing string (George E. King Enineering, 2009).

When calculating the worst case collapse pressure it is assumed that the well is filled with 40 % gas and 60 % mud. The gas will be in the upper 40 % of the well and the mud will be in the lower 60 % of the well, this is shown in figure 3.5.

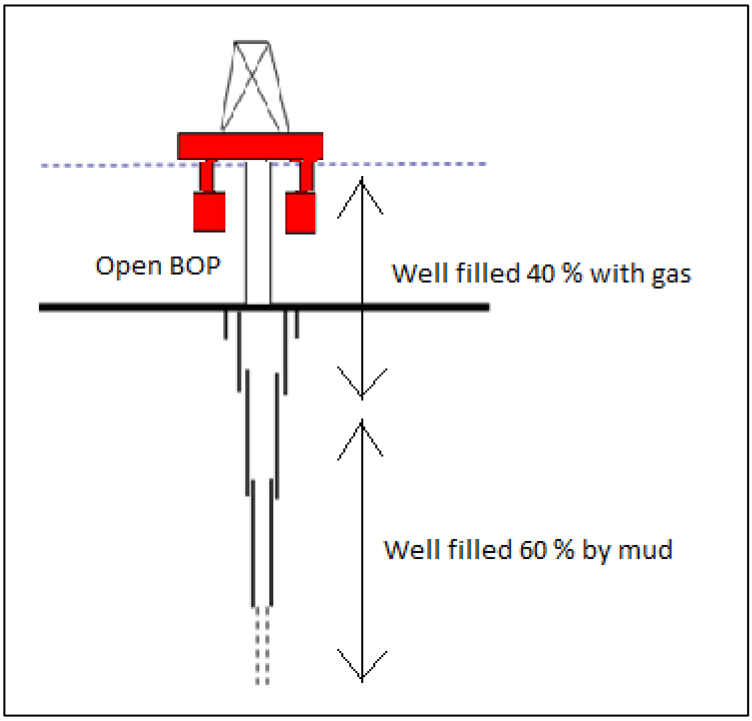

Figure 3.5: Worst case scenario for collapse pressure.

Since the BOP is open, the gas will be very close to being weightless, and the gas density is therefore assumed to be 0 kg/m^3 in the collapse calculations.

To be able to calculate the worst case collapse pressure, we first need to calculate the worst case pressure inside the wellbore ($P_{inside,collapse}$) given in bars. This pressure is calculated by using equation 3.3.

$$P_{inside,collapse} = (\rho_{gas} \times g \times h_{gas} + \rho_{mud} \times g \times h_{mud}) \times 10^{-5} \quad (3.3)$$

Where ρ_{gas} is the density of the gas given in kg/m^3, g is the constant of gravity, which is 9,81 m/s^2, h_{gas} is the height of the gas column in the wellbore measured from RKB and down to the calculation point, but not below 40 % down the well since this part will be filled with mud. ρ_{mud} is the density of the mud, given in kg/m^3, and h_{mud} is the height of the mud column from the top of the mud column and down to the calculation point, given in meters. Since the gas density is assumed to be 0, the term $\rho_{gas} \times g \times h_{gas}$ can be neglected from equation 3.3 because it will always be zero.

Now the worst case differential collapse pressure can be calculated, using equation 3.4.

$$P_{collapse} = P_{outside} - P_{inside,collapse} \qquad (3.4)$$

Where $P_{collapse}$ is the differential collapse pressure that the casing has to withstand, $P_{outside}$ is the formation pressure at the given depth and $P_{inside,collapse}$ is the worst case pressure inside the wellbore.

Whether the worst case collapse pressure is found at the upper or bottom part of the casing strings depends on the mud weight in the well and the gradient of the pore pressure in the interval. In the upper part of the well where we have gas gradient, the worst case collapse pressure is always found at the bottom of each casing. In the part where we have mud gradient, the worst case collapse pressures will be at the top of the casings if the formation gradient is steeper than the mud gradient in the interval. If the mud gradient is steeper than the formation gradient in the interval, the worst case collapse pressures is at the bottom of the casings. The worst case differential collapse pressure can also be found in the middle or anywhere on the casing, depending on the pore pressure. The easiest way to find the point for the worst case pressure is to plot the pore pressure versus $P_{inside,collapse}$ and find the point with the greatest separation between the lines. Figure 2.6 show the different gradients for a worst case collapse pressure scenario. From the figure we see that the upper 40 % of the well has gas gradient, this gas gradient is steep because the gas is weightless since it is not pressurized when the BOP is open. In the lower 60 % of the well we have the mud gradient since this part is filled with mud.

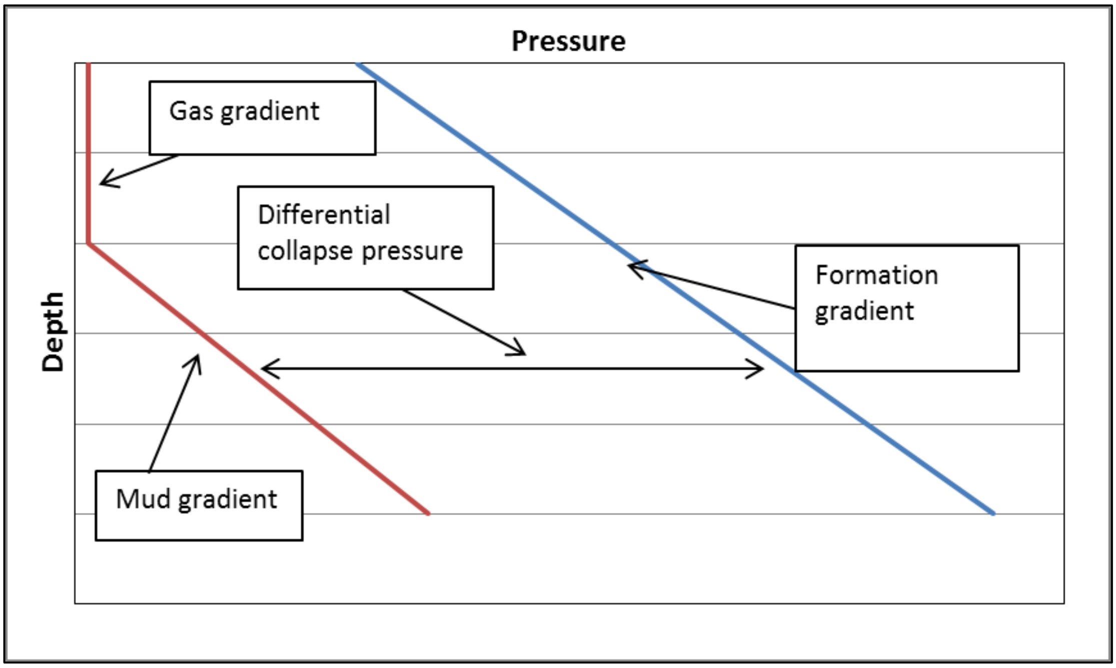

Figure 3.6: Pressure gradients for worst case collapse pressure.

3.3 Pressure rating

After the worst case burst and collapse pressures are found, the pressures are added a safety margin, this is done by using equation 3.5, this is done to make sure that the casings will hold the pressures. This is done both for the burst and collapse pressures.

Pressure rating = Worst case pressure x SF (3.5)

For burst, a safety factor of 1.10 – 1.30 is common, and for collapse a safety factor of 0.85 – 1.25 is used (Skaugen 1997). Based on this, we will add a safety margin of 1,2 both for the burst and collapse pressures.

After adding the safety factor, the pressures included safety factor is used to find the required casing strength for a safe well design.

4. Pressure loss

When mud is circulated in the wellbore there will be a frictional pressure loss. The pressure loss mainly comes from three parts of the well, this is the pressure loss in the drill string, the nozzles and the pressure loss in the annulus between the drill string and the casing/OH. The total frictional pressure loss is the minimum pump pressure that the mud pumps have to deliver to be able to circulate the mud with the desired annular velocity in the well. The pump pressure is calculated from equation 4.1.

$$P_{pump} = P_{f,drillstring} + P_{f,nozzles} + P_{f,annulus} \tag{4.1}$$

Where P_{pump} is the pump pressure that the mud pumps have to deliver, $P_{f,drillstring}$ is the pressure loss inside the drill string, $P_{f,nozzles}$ is the pressure loss in the nozzles and $P_{f,annulus}$ is the pressure loss in the annulus. The higher the velocity of the mud, the higher the pressure loss will be. The pressure loss also increases with decreasing flow area.

Since there is a pressure loss in the annulus, the bottom hole pressure will increase during circulation of mud, compared to when mud is not circulated. Calculating the bottom hole pressure when mud is not circulated in the well is easily and straightforward by using equation 4.2.

$$P_{bottom\ hole} = \rho_m \times g \times h_{well} \times 10^{-5} \tag{4.2}$$

In this equation ρ_m is the mud weight given in kg/m^3, g is the constant of gravity, which is equal to 9,81 m/s^2 and h_{well} is the vertical height of the well given in m RKB. This will give us $P_{bottom\ hole}$ in bars.

When circulating mud, ECD is used to calculate the bottom hole pressure, this is a method that takes the pressure loss in the well into consideration. It is only the pressure loss in the annulus that contributes to the ECD. The ECD is calculated given in kg/m^3 using equation 4.3.

$$ECD = \rho_m + \frac{P_{f,annulus}}{g \times l} \tag{4.3}$$

Where ρ_m is the density of the mud given in kg/m^3, $P_{f,annulus}$ is the friction loss in the annulus of the well given in Pascal, and l is the length of the well given in meters, measured along the trajectory of the well. g is the constant of gravity which is equal to 9,81 m/s^2.

After calculating the ECD, the bottom hole pressure can be calculated using equation 4.4.

$$P_{bottom,\ circulating} = ECD \times g \times h_{well} \times 10^{-5} \tag{4.4}$$

In this equation $P_{bottom,\ circulating}$ is the bottom hole pressure in the well during circulation given in bar, g is the constant of gravity and h_{well} is the vertical height of the well given in m RKB.

5. Well design

Wells can be designed in many different ways, especially for a slender well there are many different ways of designing the well. While for a conventional well there is a more standard design.

Here we will look at different designs for drilling both exploration and production wells. For designing the wells, pressure data from a field in the North Sea is used. The pore and fracture pressures for the field is shown in Figure 5.1. Raw data for the pressures are listed in appendix I. The well is a HPHT well with a reservoir pressure of 932 bar.

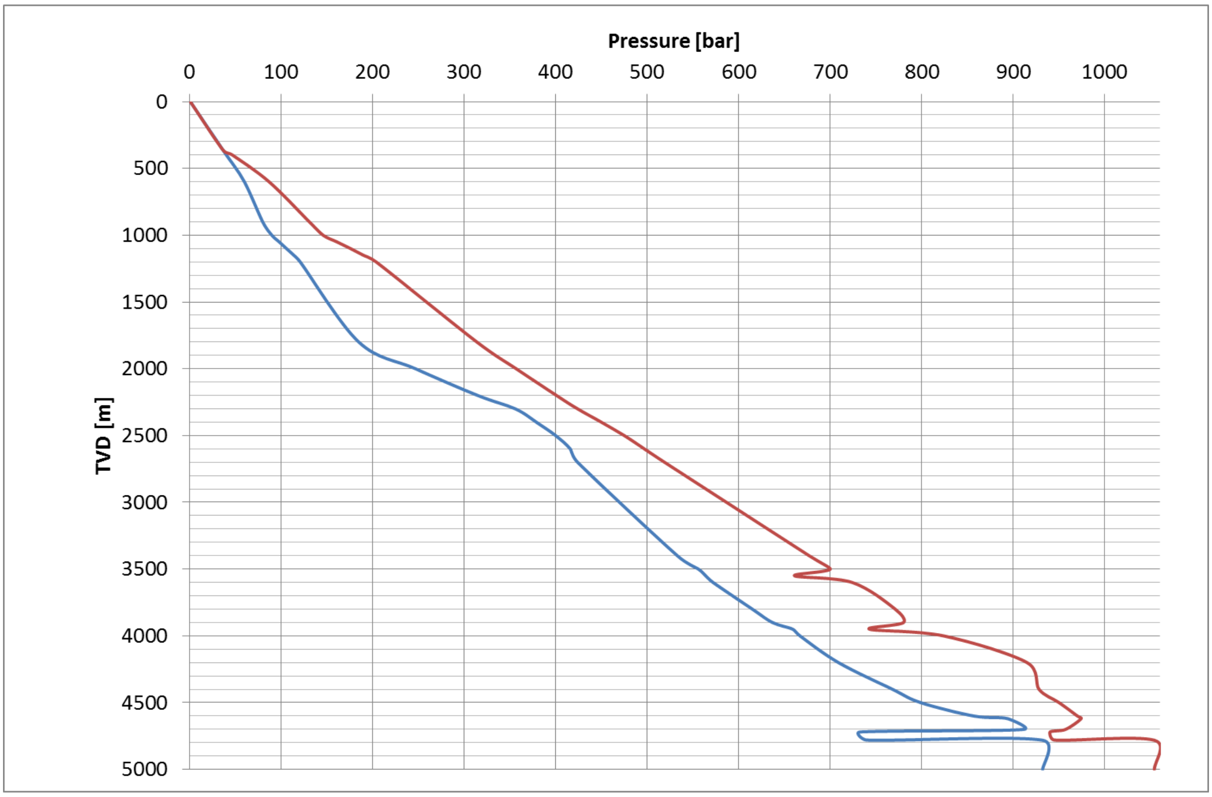

Figure 5.1: Pore and fracture pressures for the given field.

When designing a well, it might be easier to have the pressures plotted in equivalent densities. To get the pressures plotted as equivalent pore and fracture densities, the pressures are converted by using equation 5.1.

$$\rho = \frac{P}{g \times h} \times 10^5 \qquad (5.1)$$

Where ρ is the density given in kg/m^3, P is the pressure given in bar, g is the constant of gravity which equals 9,81 m/s^2 and h is the vertical depth given in m from RKB. Now the equivalent densities for the pore and fracture curves are plotted in figure 5.2. In the figure there is added a safety margin of 0,03 s.g. for the pore pressure and a safety margin of 0,01 s.g. for the fracture pressure. These margins are necessary to drill more safely. The water depth for the field is 360 m, and the RKB is located 20 m above the sea level.

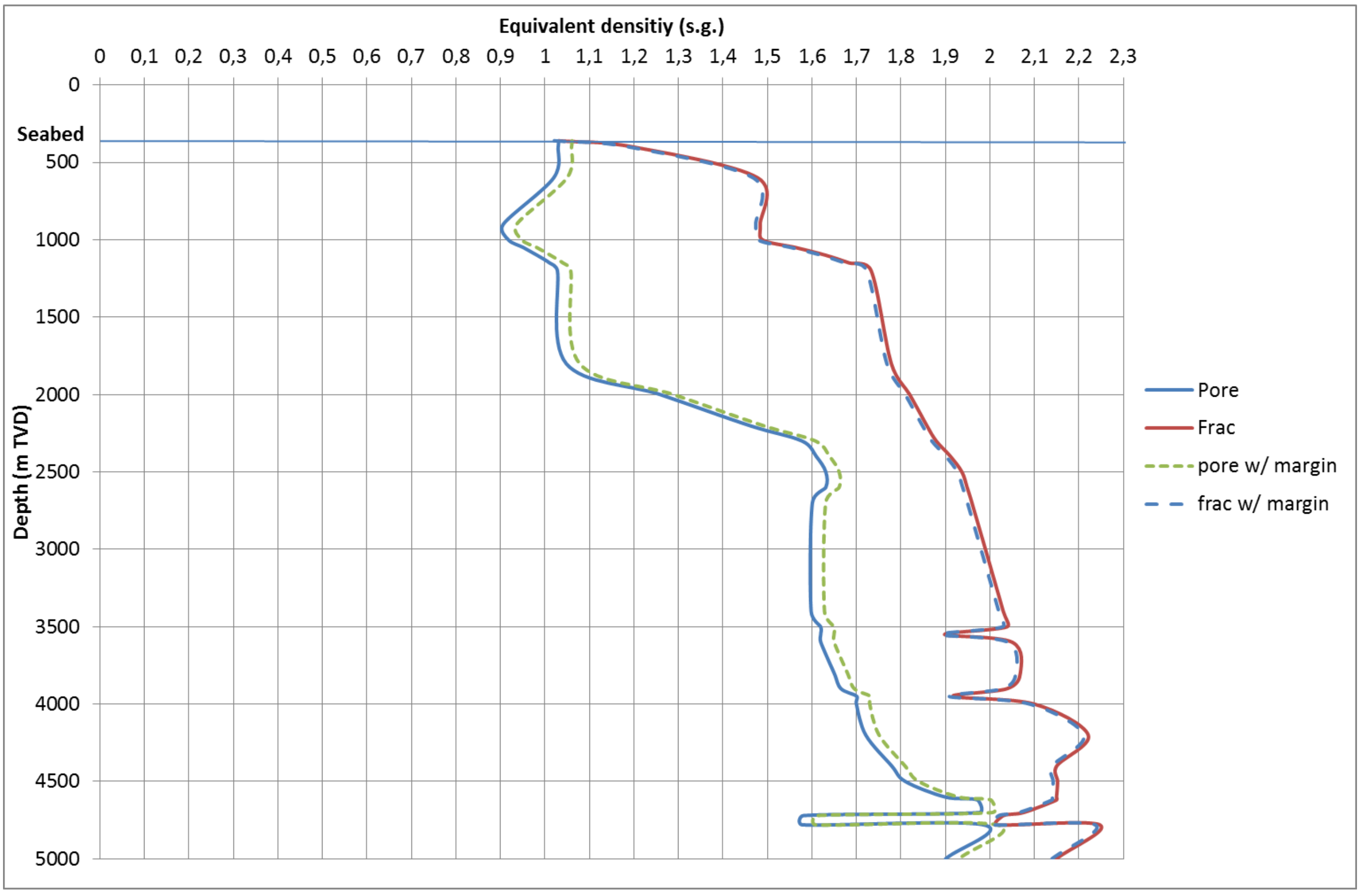

Figure 5.2: Equivalent pore and fracture- pressure curves.

After plotting the equivalent densities, the mud weight is selected so that it will be inside the mud window during drilling of the sections. It is important to drill a section with a mud weight that keeps the pressure in the well in between the pore pressure and the fracture pressure. While drilling, the mud weight always has to be above the pore pressure gradient to prevent influx from the formation. Since the pressure in the well increases when circulating in the well, the ECD always has to be below the fracture pressure to prevent the pressure in the well of fracturing the formation.

5.1 Conventional well design

The most common way to design a well is to start out with a 36” drill bit and ending up with an 8 ½” bit size in the final section. Normally the riser used has an OD of 21” and an ID of 19”, the riser is connected after installing the 20” surface casing, meaning that the two first sections are drilled riser less using sea water as mud and with return to sea bed. The drill bit sizes and casing sizes normally used are shown in table 5.1. This design is also shown in figure 5.3.

Table 5.1: Typical drill bit and casing sizes for a conventional well.

Drilled hole size (Inches)	Casing size (Inches)
36”	30”
26”	20”
17 1/2”	13 3/8”
12 1/4”	9 5/8”
8 1/2”	7” (liner)

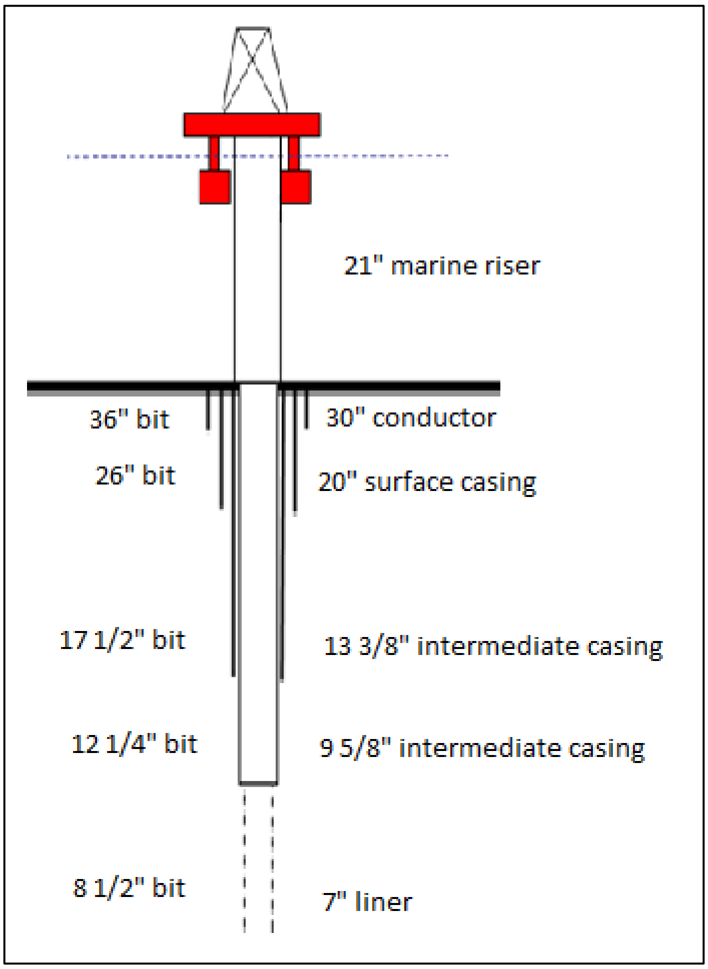

Figure 5.3: Conventional well design including bit and casing sizes.

To have a base case for comparing amount of drill cuttings, steel, mud and cement, we design a conventional well. This will later be compared with some slender well designs to see the savings. The pressure data for the well included selected mud weights are presented in figure 5.4. The 17 1/2" section is set to be 950 m below the 20” casing shoe, even though this section could have been drilled deeper. This is due to that the third section of the slender well designs that will be compared to the conventional design has a 950 m third section. The reason could also be that unexpected problems were faced during drilling so that the drilling had to stop, and the casing had to be set.

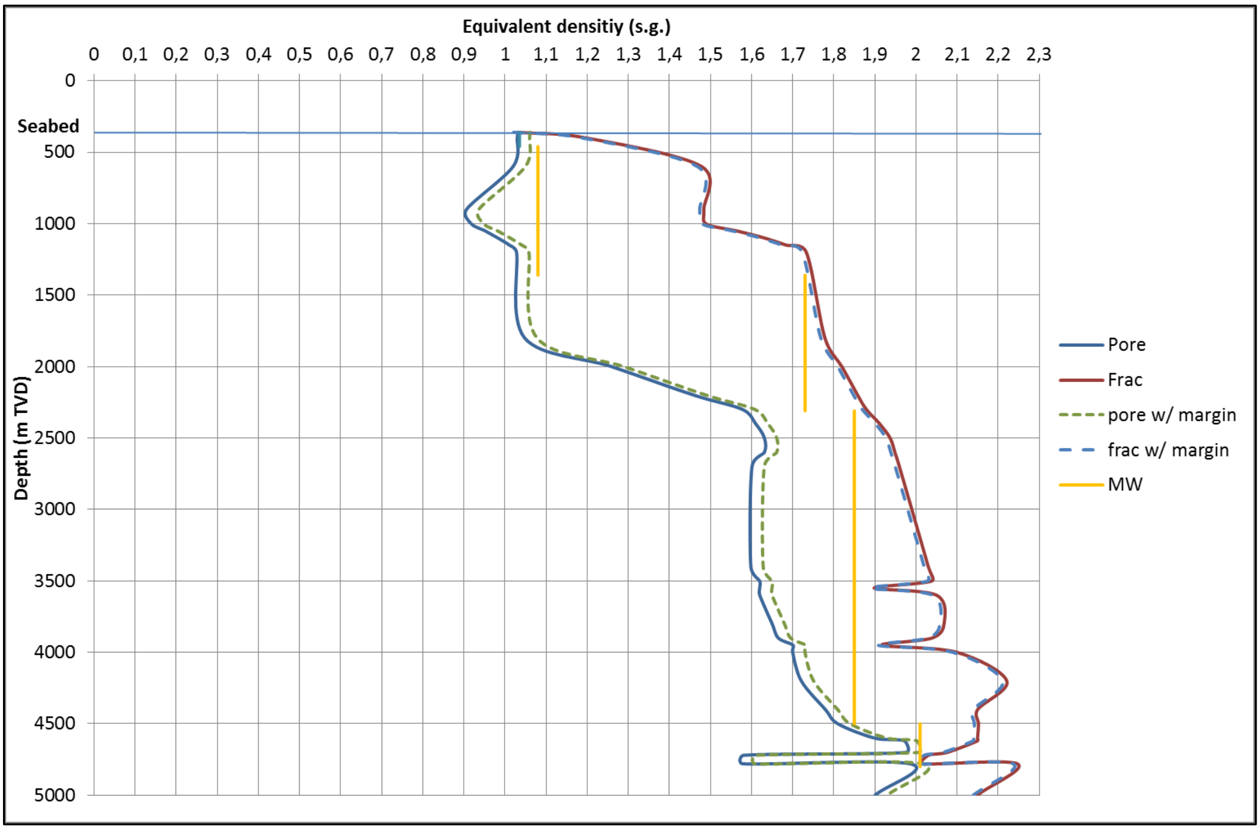

Figure 5.4: Pressure data for drilling of a conventional well including mud weights.

The sections drilled and the casing setting depths are presented in table 5.2, together with the maximum pore pressure for drilling the different sections. The maximum pore pressure for the two first sections are not included because they are not needed for the casing design since these two sections are drilled riser less and without BOP The water depth is 360 m, and the RKB elevation is 20 m.

Table 5.2: Sizes, depths and mud weights for a conventional well.

Drilled hole size [Inches]	MW [s.g.]	Casing size [Inches]	TD of section/Shoe depth [m RKB]	Maximum pore pressure [bar]
36”	1,035	30”	480	-
26”	1,08	20”	1380	-
17 1/2”	1,73	13 3/8”	2330	358
12 1/4”	1,85	9 5/8”	4520	799
8 1/2”	2,01	7” (liner)	4820	932

When doing the casing design for the well, the casings set are designed to be able to withstand the maximum pore pressure of the section below, the casing design rules from chapter 3 are used for the casing design. Since the section below the 30” casing is drilled riser less and without BOP, this casing will not be critical for the casing design, so the casing design will start with the 20” casing using the maximum pore pressure from drilling the 17 1/2" section. The next will be the 13 3/8” casing that uses the maximum pore pressure from the 12 1/4" section. Then the 9 5/8” casing that uses the maximum pore pressure from the 8 1/2" section, the 7” liner also uses the maximum pore pressure from the 8 1/2" section. The worst case burst pressures are presented in table 5.3. All burst pressures are calculated at the top of each casing/liner.

Table 5.3: Worst case burst pressures for the conventional well.

Casing/liner size [inches]	P_{pore} [bar]	$P_{inside,burst}$ [bar]	P_{burst} [bar]
20”	36	314	278
13 3/8”	159	728	569
9 5/8”	358	875	517
7”	799	925	126

For calculating the worst case collapse pressures, we first calculate the gas and mud heights in the well with the mud weights used for drilling the sections. After finding the mud and gas gradients, these are plotted together with the pressure data for the field, the worst case well pressures are plotted in figure 5.5.

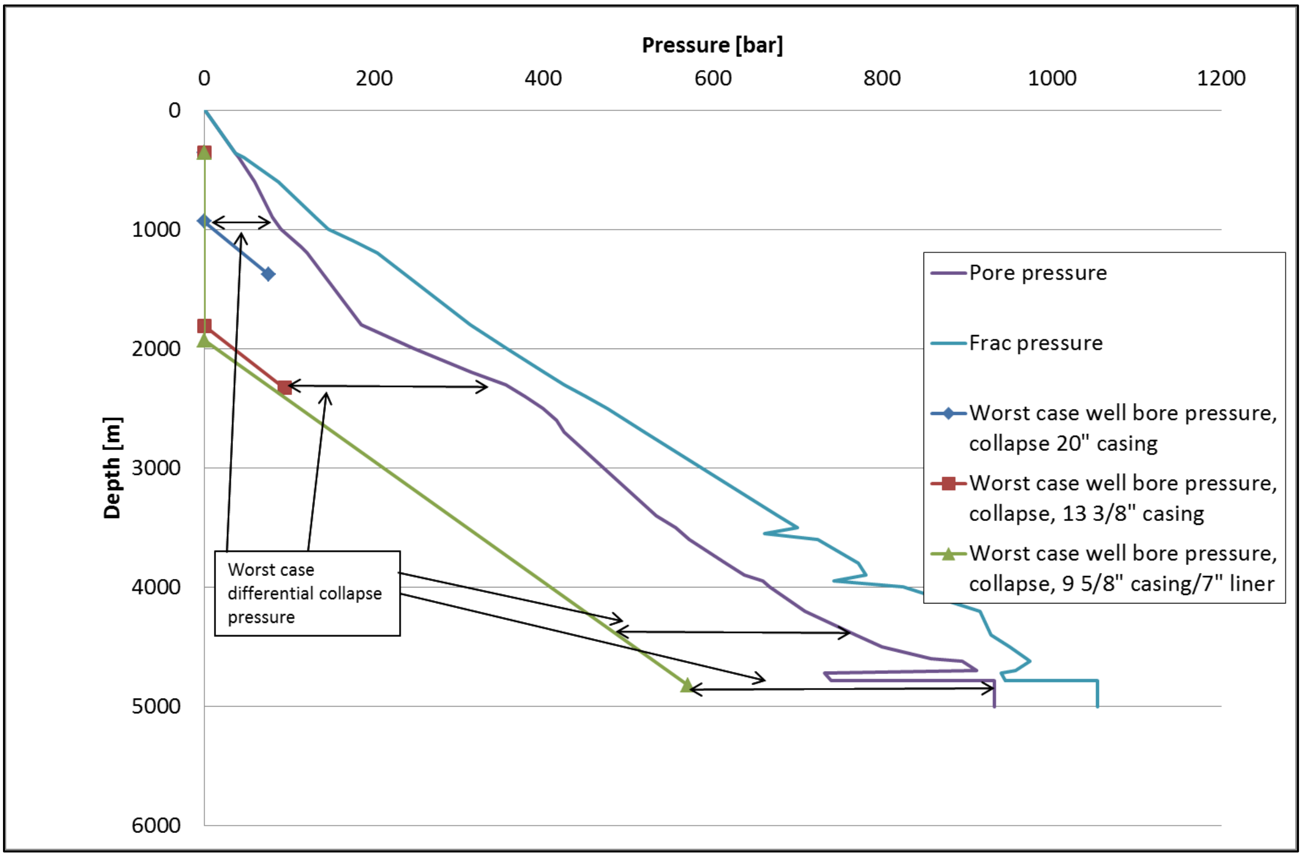

Figure 5.5: Worst case differential collapse pressures for the conventional well.

From the figure we can find the depths for the worst case differential collapse pressures for each casing. The depths that are found in the figure are presented in table 5.4, together with the collapse pressures.

Table 5.4: Worst case collapse pressures for the conventional well.

Casing/liner	Worst case collapse depth [m RKB]	Well pressure at depth [bar]	P_{pore} at depth [bar]	Differential collapse pressure [bar]
20”	932	0	81	81
13 3/8”	2330	95	358	263
9 5/8”	4520	511	799	288
7”	4820	570	932	362

Now we will add a safety factor of 1,2 to both collapse and burst pressures, this is to secure that the design is safe. The burst and collapse pressures excluding and including SF are presented in table 5.5.

Table 5.5: Burst and collapse pressures including and excluding SF for the conventional well.

Casing/liner	Collapse pressure without SF [bar]	Collapse pressure with SF [bar]	Burst pressure without SF [bar]	Burst pressure with SF [bar]
20”	81	97	278	334
13 3/8”	263	316	569	683
9 5/8”	288	346	517	620
7”	362	434	126	151

Now we can find the casings/liner that we need to design the well. Table 5.6 presents the selected casing and liners, with their specifications, the casing properties are taken from Vallourec & Mannesmann tubes. Connection ID and OD are not included in the conventional design, due to the fact that this will not be a problem using the conventional design.

Table 5.6: Casing/liner properties for the conventional well design.

Casing/liner OD [Inches]	20” casing	13 3/8” casing	9 5/8” casing	7” liner
Grade	C95	Q125HC	P110 EC	P110 EC
Weight [lb/ft]	133,00	77,00	43,50	26,00
Wall thickness [inches]	0,635	0,550	0,435	0,362
Drift [Inches]	18,543	12,119	8,599	6,151
Collapse resistance [bar]	110	301	398	554
SF collapse	1,36	1,15	1,38	1,53
Burst resistance [bar]	364	670	682	780
SF burst	1,31	1,18	1,32	6,19

5.2 Slender well designs

Designing slender wells can be done in many different ways, both for exploration and production wells. Common for all designs are that the diameters of the upper sections are significantly reduced compared to the conventional well design.

5.2.1 Slender exploration wells

For an exploration well, the limitation regarding final hole size often is the size of the logging tool and the equipment strength. There are nowadays possible to log slim holes with diameters all the way down to 3", giving the same quality of the data as for logging larger diameter holes. These tools have a short and lightweight design that are easy to navigate in wells with high dogleg severity, and are easy to push with well tractors and coiled tubing (Ariwodo et al. 2010). However in most wells a minimum hole size of 4 3/8" is desired due to the challenges of drilling small holes. The smaller the hole is, the weaker the equipment, and there are also challenges regarding frictional pressure loss while drilling narrow holes.

5.2.1.1Slender exploration well example I

Here we will take a look at a slender exploration well design. The design uses a small diameter riser with an ID of 8 5/8". Table 5.7 presents the bit and casing/liner sizes used in the well. The two first sections are drilled riser less and without BOP. The 11 3/4" surface casing has a pre-installed liner with a diameter of 9 5/8" inside, this liner is set in the third section of the well after the section has been drilled with an expandable reamer with a diameter of 12 1/4". Using a pre-installed liner is a good solution because a liner with a larger diameter than the ID of the riser can be set, due to the fact that the liner is already in the well bore before the BOP and riser are installed, and before drilling of the section where it is going to be placed. Also the 8 1/2" section has to be drilled with an expandable reamer due to the ID of the 9 5/8" liner and the ID of the riser, here a 7 7/8" bit with 8 1/2" reamers is selected. The diameter of the final section is planned to be drilled with 5 7/8" bit, with an open hole completion. A sketch of the well is shown in figure 5.6.

Table 5.7: Bit and casing/liner sizes for the exploration wells.

Bit size [inches]	Casing/liner size (OD) [inches]
22"	20" conductor
14"	11 3/4" surface casing
8 1/2" x 12 1/4" UR	9 5/8" PIL
7 7/8" x 8 1/2" UR	7" Liner
5 7/8"	5 7/8" OH

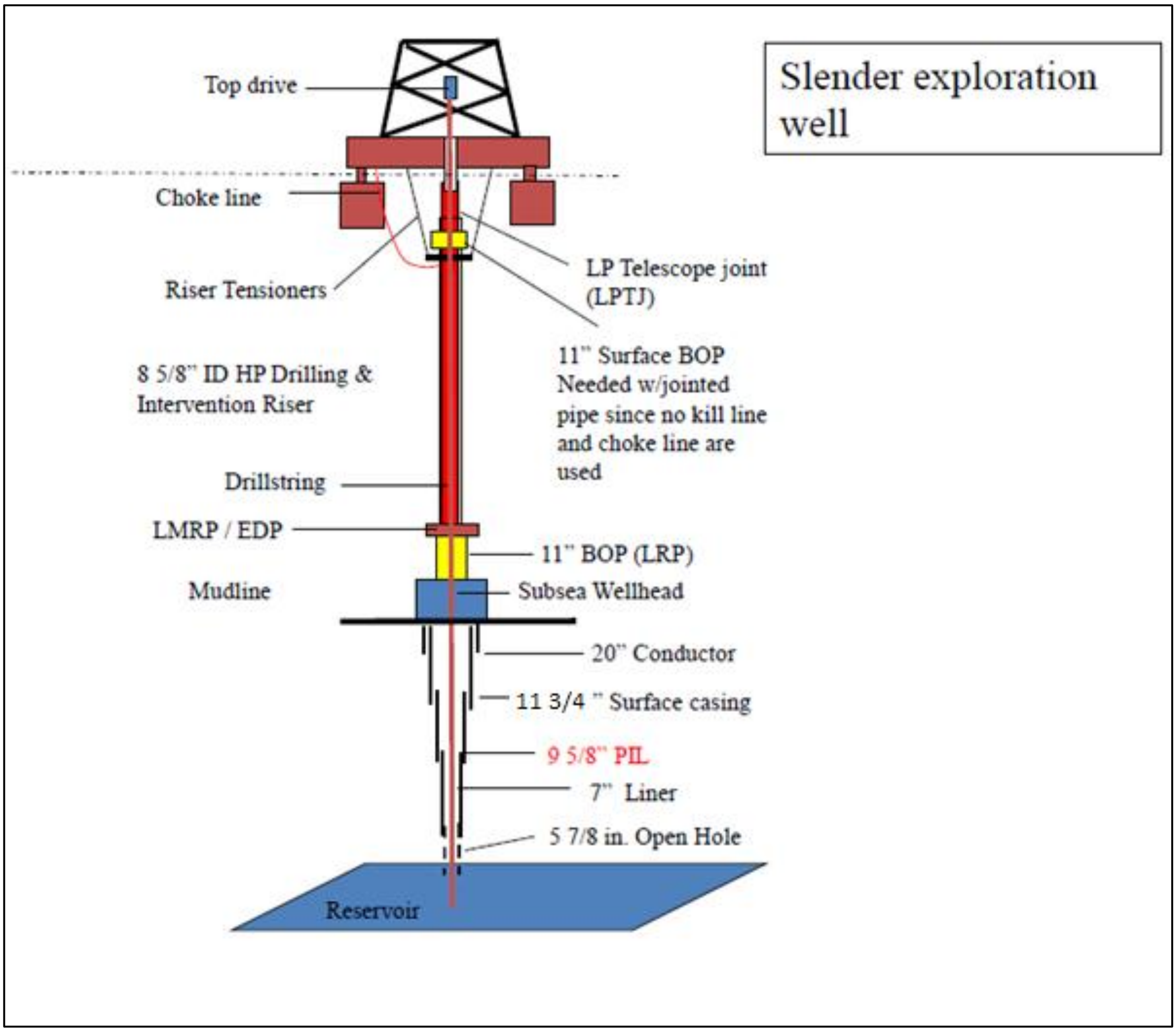

Figure 5.6: Example of a slender exploration well (Sangesland 2012).

The casing and liner setting depths are found by using the pressure data for the well, the mud weights and drilling depths are shown in figure 5.7. The third section where the 9 5/8" PIL is going to be placed, cannot be drilled more than 950 m below the 11 3/4" casing shoe due to the length limitation of using a PIL. A PIL cannot be longer than the length of the previous casing, because it is run together with the previous casing.

A drill string with an OD of 5" and an ID of 4,276" is used for drilling the two first sections, which is the 22" and the 14" section. The drill string used for drilling the sections after connection of the riser and BOP has an OD of 3,5" and an ID of 2,764". The diameter of the drill string has to be limited due to the small bore riser. It is necessary to use the larger 5" drill pipe in the upper sections due to the pressure loss inside the string, which will be very high because of the high flow rate used in the two first sections. Another important aspect about using a larger diameter drill pipe in the first sections is the large size difference between the string and the DC and bit used.

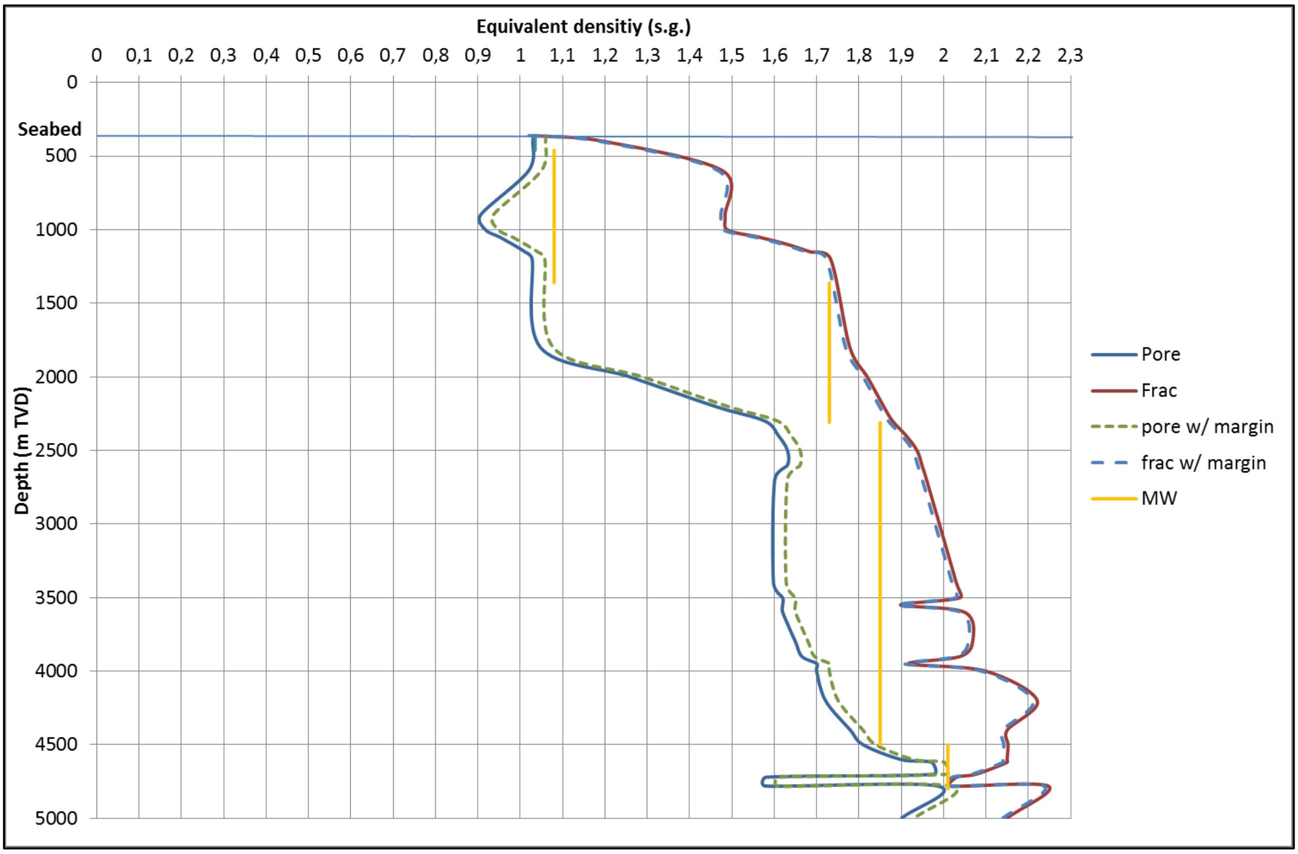

Figure 5.7: Drilling depths and selected mud weights for drilling exploration well I.

The casing setting depths from figure 5.7 are listed in table 5.8. Target depth of the well is 4820 m RKB.

Table 5.8: Sizes and depths for drilling exploration well I.

Section drilled [inches]	Casing/liner size [inches]	Target depth of section [m RKB]	Length of casing/liner [m]
22”	20” casing	480	100
14”	11 3/4” casing	1380	1000
8 1/2" x 12 1/4" UR	9 5/8” PIL	2330	950
7 7/8” x 8 1/2" UR	7” liner	4520	2190
5 7/8”	OH	4820	300 OH

The worst case burst and collapse pressures for the well are now calculated using equations from chapter 3, and are presented in table 5.9 and 5.10. The collapse calculations are done with a mud weight of 2,01 s.g.

Table 5.9: Worst case burst pressures for exploration well I.

Casing/liner size [inches]	P_{pore} [bar]	$P_{inside,burst}$ [bar]	P_{burst} [bar]
11 3/4"	36	831	795
9 5/8"	159	854	695
7"	358	875	517

Table 5.10: Worst case collapse pressures for exploration well I.

Casing/liner size [inches]	P_{pore} [bar]	$P_{inside,collapse}$ [bar]	$P_{collapse}$ [bar]
11 3/4"	159	0	159
9 5/8"	356	75	281
7"	799	507	292

The worst case well pressures for both burst and collapse are plotted in figure 5.8. Here the worst case well pressures are plotted for burst and collapse, and the differential burst pressure will be the difference between the worst case well pressure, burst and the pore pressure curve. The differential collapse pressure is the difference between the worst case well pressure, collapse and the pore pressure curve.

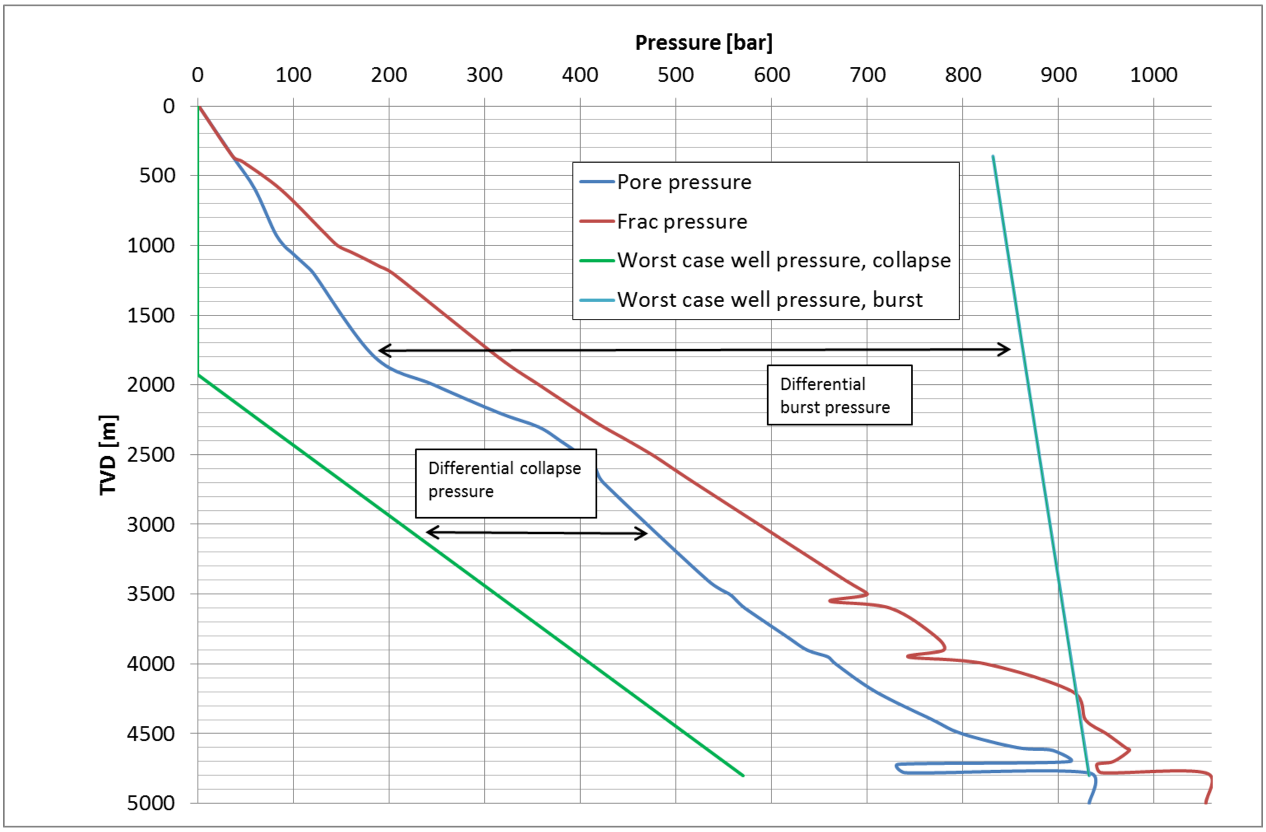

Figure 5.8: Worst case well pressures for burst and collapse in exploration well I.

The differential burst and collapse pressures are plotted in figure 5.9. Here we see that the differential burst pressure increase significantly upwards, due to the light density of the gas in the well. The differential collapse pressure increases from the top of the well and down to the part of the well that is filled with mud. From this point and down to TD of the well, the differential collapse pressure stabilizes, this is due to the fact that the density of the fluid in the well and the density of the formation fluid is almost the same. From looking at figure 5.8, the worst case collapse pressure for the 7" liner was found to be at 4520 m RKB.

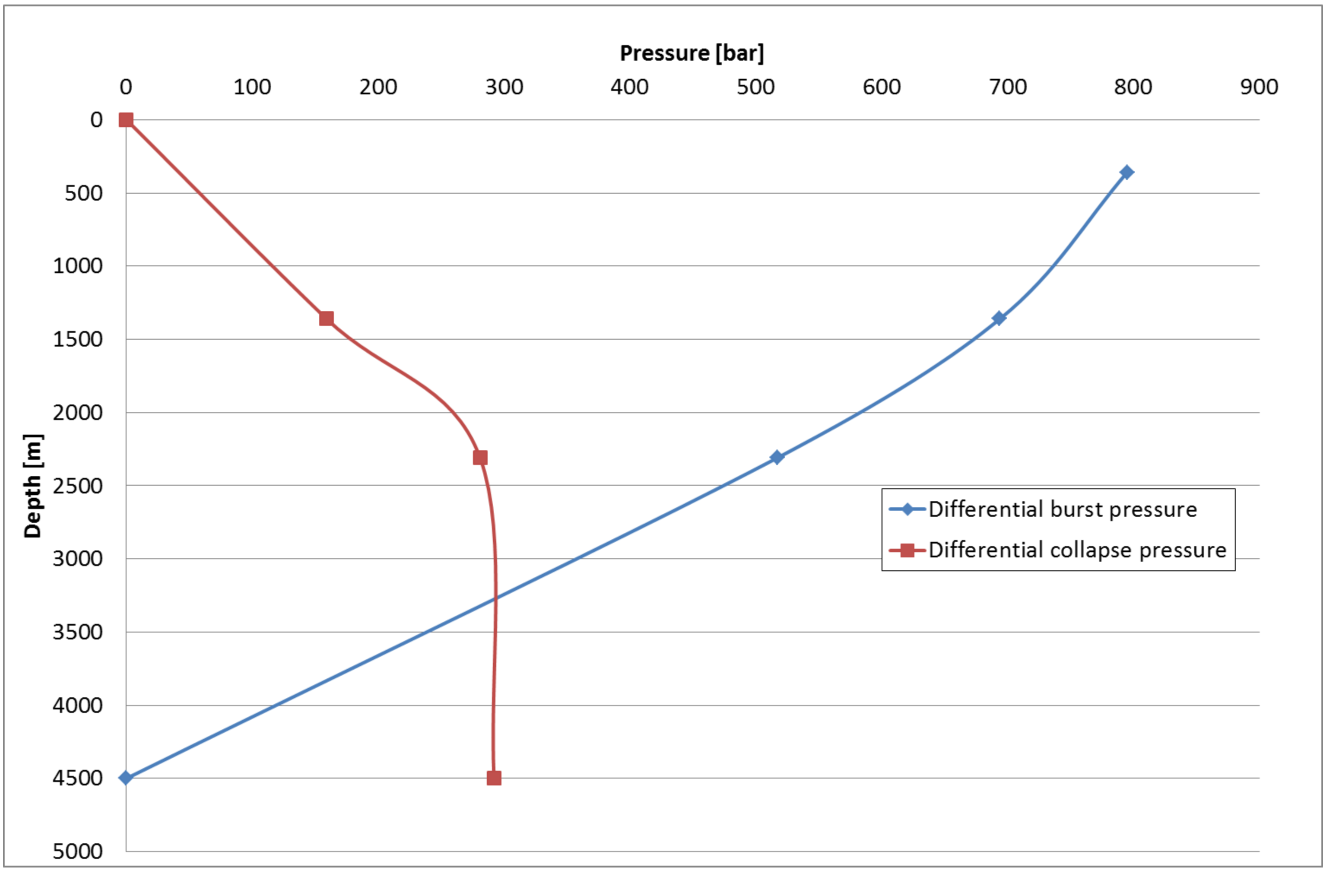

Figure 5.9: Differential burst and collapse pressures for exploration well I.

After the worst case pressures are found, they are added a safety factor of 1,2, to secure that the casings/liners can withstand the pressures. The pressures including SF are presented in table 5.11.

Table 5.11: Collapse and burst pressures including and excluding SF for exploration well I.

Casing/liner	Collapse pressure without SF [bar]	Collapse pressure with SF [bar]	Burst pressure without SF [bar]	Burst pressure with SF [bar]
11,3/4" casing	159	191	795	954
9 5/8" liner	281	337	695	833
7" liner	292	350	520	624

The next step is to select casings and liners that can withstand the pressures that where calculated. Table 5.12 presents the selected casing and liners, with their specifications, the casing properties are taken from Vallourec & Mannesmann tubes, and VAM Book. The burst SF for the 11 3/4" casing is only 1,14, but this is sufficient, because a safety factor of 1,1 – 1,2 is sufficient for burst pressures (Skaugen 1997).

Table 5.12: Casing and liner selection with properties, for exploration well I.

Casing/liner OD [Inches]	11 3/4" casing	9 5/8" liner	7" liner
Grade	Q125 HCE	P110 EC	P110 EC
Weight [lb/ft]	79,00	53,50	26,00
Wall thickness [inches]	0,656	0,545	0,362
Drift [Inches]	10,282	8,379	6,151
Coupling ID [inches]	10,361	8,558	6,220
Coupling OD [inches]	12,035	9,855	7,084
Collapse resistance [bar]	689	630	554
SF collapse	4,3	2,24	1,58
Burst resistance [bar]	910	854	780
SF burst	1,14	1,23	1,50

It is important that the OD of the coupling for the casing/liner that is going to be set is larger than the drift diameter of the previous casings/liners that are set. Now we can calculate the clearances between the casing/liner set and the previous casing/liner by taking the drift diameter of the previous casing minus the coupling OD for the next casing/liner and divide the answer by two. The clearance between the 20" casing and the 11 3/4" casing will not be a problem and is therefore not included in the calculations.

The clearance between the casings/liners is:

- Between the 11 3/4” casing and the 9 5/8” liner: **0,21” = 0,53 cm**
- Between the 9 5/8” liner and the 7” liner: **0,65” = 1,65 cm**

We see that there is clearance between the casings, this means that the design is possible to construct. Since the clearances are above the minimum radial clearance for the use of close clearance liners which is 1/8” = 0,125” (Howelett et al. 2006).

Now that the casing design is complete, the pressure losses from drilling the different sections are calculated. The drill pipe used in the 22” and 14” sections has an OD of 5” and an ID of 4,276”, while the drill pipe used in the rest of the sections has an OD of 3,5” and an ID of 2,764”. The length of the drill collars is 70 meters for the sections that are larger than 8 1/2", and 30 meters for the sections from 8 1/2" and smaller. All pressure loss calculations are done in Mud Calc. The pressure losses and the selected flow rates are together with v_{min}, which is the annular velocity in the largest section, presented in table 5.13. In addition to the pressure loss in the drill pipe, annulus and bit, there are also some pressure loss from motors, surface equipment and MWD. The minimum annular velocity is important because it affects hole cleaning, the drill cuttings will not be lifted up to the surface if the annular velocity is too low. If the drill cuttings accumulate in the well, it can cause serious problems like stuck pipe.

By using a 5” drill pipe instead of a 3,5” drill pipe in the two first sections, the pressure loss inside the drill string is reduced from 118,3 and down to 28,2 bar if the flow rate is kept constant at 4000 l/min. The pressure loss inside the drill string for drilling the 14”section will be reduced from 227,4 and down to 40,5 bar by using a 5” drill pipe, keeping a constant flow rate of 3000 l/min.

Table 5.13: Pressure losses for drilling exploration well I.

Section drilled	22”	14”	8 1/2" x 12 1/4" UR	7 7/8” x 8 1/2" UR	5 7/8”
Casing/liner set	20” casing	11 3/4" casing	9 5/8” PIL	7” liner	OH
Length of section [m]	100	1000	950	2190	300
MW [s.g.]	1,035	1,08	1,73	1,85	2,01
ECD at top of section [s.g.]	1,035	1,081	1,737	1,858	2,034
ECD at bottom of section [s.g.]	1,036	1,083	1,738	1,859	2,036
Pressure loss DP [bar]	28,2	40,5	167,7	194,3	123,2
Pressure loss annulus [bar]	0,0	0,5	1,5	4,0	12,4
Pressure loss bit [bar]	45,1	42,4	14,8	25,5	7,6
v_{min} [m/s]	0,28	0,29	0,33	0,35	0,29
Flow rate [l/min]	4000	3000	1400	1000	700
Pump pressure [bar]	145	132	210	243	158

Now all calculations are done, and the ECD is plotted together with the mud weight in figure 5.10. We see that the ECD is almost the same as the mud weight, this is due to the low circulation rate in the well.

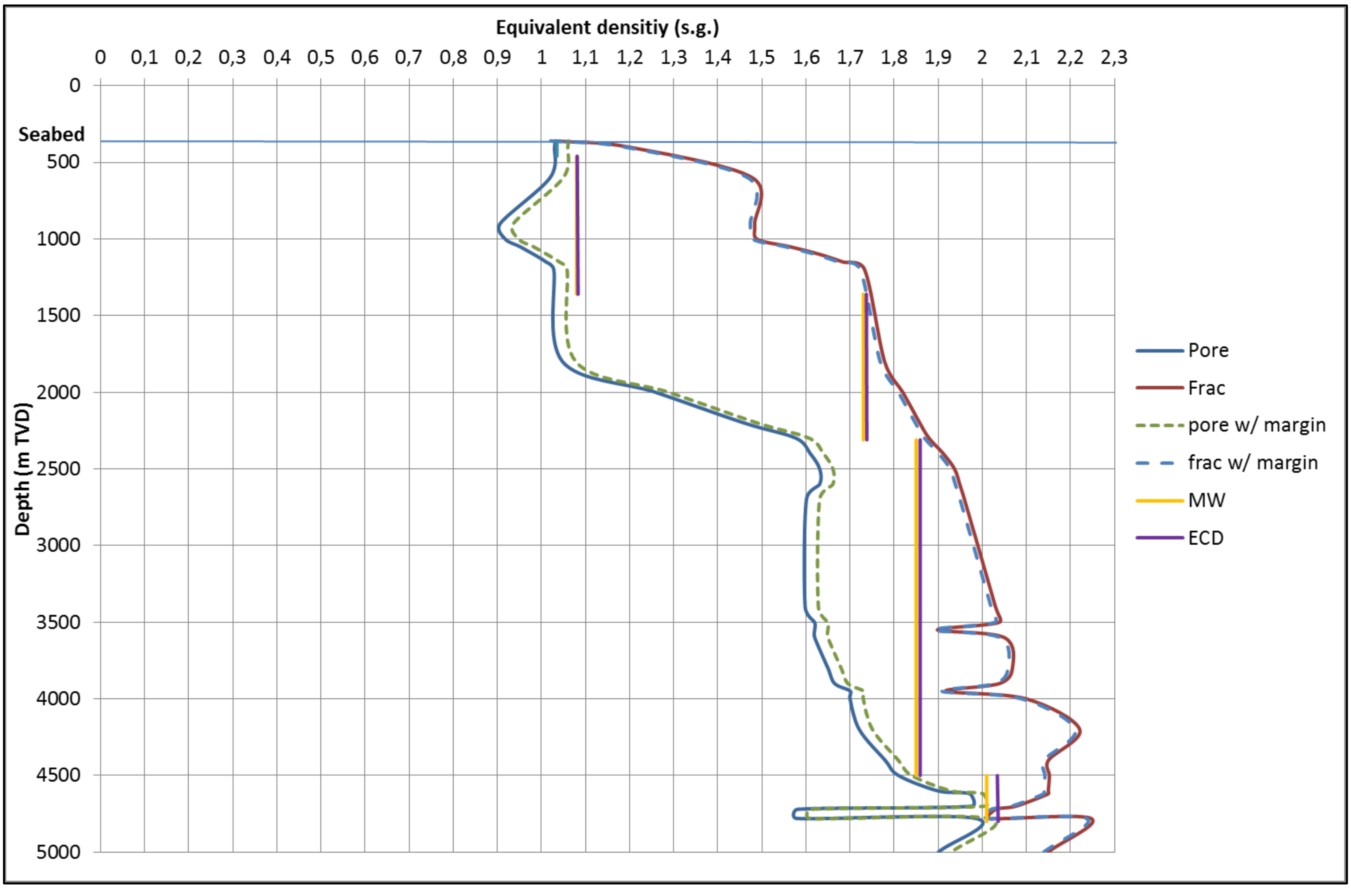

Figure 5.10: Drilling programme with mud weights and ECD for exploration well I.

We see that the last section can be challenging to drill due to the narrow mud window. If the section cannot be drilled due to ECD, different drilling techniques such as MPD can be used to be able to drill the well to TD at 4820 m RKB.

5.2.1.2 Slender exploration well example II

In this example we will try to design a 15 000 psi well, by increasing the reservoir pressure from the previous well to 15 000 psi (1034 bar). The water depth and casing setting depths remain the same. Increasing the reservoir pressure will increase the worst case burst pressures and make the casing design more difficult. The sections drilled and casings installed with their setting depths and lengths are presented in table 5.14.

Table 5.14: Sections drilled with depths and sizes for exploration well II.

Section drilled [inches]	Casing/liner size [inches]	Target depth of section [m RKB]	Length of casing/liner [m]
22”	20” casing	480	100
14”	11 3/4” casing	1380	1000
8 1/2" x 12 1/4" UR	9 5/8” PIL	2330	950
7 7/8” x 8 1/2" UR	7” liner	4520	2190
5 7/8”	OH	4820	300 OH

The mud weights selected are presented in table 5.15. For the sections from 22” – 8 1/2" the mud weights will be the same as for exploration well I, but since the reservoir pressure is increased the mud weight for the last section will also have to be increased. Calculating the equivalent density at the reservoir using 4820 m RKB as reference will give a mud weight for the last section of 1034×10^5 Pa/(9,81 m/s^2 x 4820 m) = 2187 kg/m^3. This means that the mud weight for drilling the section has to be 2,19 s.g. to balance the pore pressure. The two first sections are drilled with sea water, and with return of drill cuttings to the sea bed.

Table 5.15: Mud weights used for drilling exploration well II.

Section drilled [inches]	MW [s.g.]
22”	1,035
14”	1,08
8 1/2" x 12 1/4" UR	1,73
7 7/8” x 8 1/2" UR	1,85
5 7/8”	2,19

The next step is to do the casing design, using equations from chapter 3, the worst case burst and collapse pressures are calculated using pressure data form the well. These worst case pressures are presented in table 5.16 and 5.17. Also in this example the 20” casing is not included in the calculations, this is due to the fact that this casing will be insulated by the 11 3/4" casing. The differential collapse pressure will increase down to 1928 m RKB, since the well in this interval is filled with weightless gas, and the formation pressure thereby increases more than pressure in the well. The worst case depths for burst and collapse will be the same as for exploration well I since the same pressure data and casing setting depths are used.

Table 5.16: Worst case burst pressures for exploration well II.

Casing/liner size [inches]	P_{pore} [bar]	$P_{inside,burst}$ [bar]	P_{burst} [bar]
11 3/4”	36	934	898
9 5/8”	159	956	797
7”	358	978	620

Table 5.17: Worst case collapse pressures for exploration well II.

Casing/liner size [inches]	P_{pore} [bar]	$P_{inside,collapse}$ [bar]	$P_{collapse}$ [bar]
11 3/4”	159	0	239
9 5/8”	356	82	274
7”	799	553	246

Now we include a safety factor of 1,2 for both the worst case burst and collapse pressures. The safety factor is added in table 5.18 which presents the burst and collapse pressures including and excluding SF.

Table 5.18: Burst and collapse pressures for exploration well II, including and excluding SF.

Casing/liner	Collapse pressure without SF [bar]	Collapse pressure with SF [bar]	Burst pressure without SF [bar]	Burst pressure with SF [bar]
11,3/4” casing	239	287	898	1078
9 5/8” liner	274	329	797	956
7” liner	246	295	620	744

After finding the burst and collapse pressures included safety factor, we have to select which casings to use. The casing properties are taken from Vallourec & Mannesmann tubes, and VAM Book. The casings selected are presented in table 5.19, included all casing/liner specifications.

Table 5.19: Casings/liners selected including properties, for exploration well II.

Casing/liner OD [Inches]	11 3/4” casing	9 5/8” liner	7” liner
Grade	Q125 HCE	Q125 HCE	P110 EC
Weight [lb/ft]	79,00	58,40	26,00
Wall thickness [inches]	0,656	0,595	0,362
Drift [Inches]	10,282	8,279	6,151
Coupling ID [inches]	10,361	8,433	6,220
Coupling OD [inches]	12,035	9,882	7,084
Collapse resistance [bar]	689	757	554
SF collapse	2,92	2,76	2,25
Burst resistance [bar]	910	1007	780
SF burst	1,01	1,26	1,26

From table 5.19, we see that the 11 3/4" casing has a SF of 1,01 for burst, this is the only SF that is below 1,2, a SF of 1,01 is too low to design the well safely because the safety factor should be 1,1 – 1,2 for burst pressures (Skaugen 1997). The 79 lb/ft 11 3/4" casing is the strongest casing in the book with casing properties (Vallourec & Mannesmann tubes). To solve this problem with the low burst rating, the casing can be special ordered with a larger wall thickness, making the OD larger, but the ID remaining the same. This can be done since the spacing between the 20” casing and the 11 3/4" casing is not critical.

It is important that the OD of the coupling for the casing/liner that is going to be set is larger than the drift diameter of the previous casings/liners that are set. Now we can calculate the clearances between the casing/liner set and the previous casing/liner by taking the drift diameter of the previous casing minus the coupling OD for the next casing/liner and divide the answer by two. The clearance between the 20” casing and the 11 3/4” casing will not be a problem and is therefore not included in the calculations.

The clearance between the casings/liners is:

- Between the 11 3/4” casing and the 9 5/8” liner: **0,20” = 0,51 cm**
- Between the 9 5/8” liner and the 7” liner: **0,60” = 1,52 cm**

We see that there is clearance between the casings, this means that the design is possible to construct since the clearances are above the minimum radial clearance for the use of close clearance liners which is 1/8” = 0,125” (Howelett et al. 2006).

The next step now is to calculate the pressure losses for drilling the well, all pressure loss calculations are done in Mud Calc. The drill pipe used has an OD of 5” and an ID of 4,276” for the two first sections which are drilled riser less and without BOP, and an OD of 3,5” and an

ID of 2,764” for the remaining sections. The length of the drill collars is 70 meters for the sections that are larger than 8 1/2", and 30 meters for the sections from 8 1/2" and smaller. The pressure losses and the selected flow rates are together with v_{min}, which is the annular velocity in the largest section, presented in table 5.20. The minimum annular velocity is important because it affects hole cleaning, the drill cuttings will not be lifted up to the surface if the annular velocity is too low. Accumulation of drill cuttings can cause serious problems like stuck pipe.

Table 5.20: Pressure losses for drilling exploration well II.

Section drilled	22”	14”	8 1/2" x 12 1/4" UR	7 7/8” x 8 1/2" UR	5 7/8”
Casing/liner set	20” casing	11 3/4" casing	9 5/8” PIL	7” liner	OH
Length of section [m]	100	1000	950	2190	300
MW [s.g.]	1,035	1,08	1,73	1,85	2,19
ECD at top of section [s.g.]	1,035	1,081	1,737	1,858	2,215
ECD at bottom of section [s.g.]	1,036	1,083	1,738	1,859	2,217
Pressure loss DP [bar]	28,2	40,5	167,7	194,3	123,2
Pressure loss annulus [bar]	0,0	0,5	1,5	4,0	12,4
Pressure loss bit [bar]	45,1	42,4	14,8	25,5	7,6
v_{min} [m/s]	0,28	0,29	0,33	0,35	0,29
Flow rate [l/min]	4000	3000	1400	1000	700
Pump pressure [bar]	145	132	210	243	158

Also for this well, drilling of the last section will be difficult due to the narrow mud window when drilling into the reservoir. Techniques such as MPD can be used to drill the well to TD.

5.2.2 Slender production wells

Slender production wells often have the same diameter of the final section as the wells that are drilled with a conventional design, but the upper part of the well are scaled down. The reason that the final section often is not scaled down is that a certain diameter is needed to get the desired production rate, the larger the diameter of the final section; the more oil will flow into the well. If the final hole size becomes too small, the production may become too low to be economically beneficial. Typically a diameter of 8 1/2” is desired when drilling the reservoir section, but sizes all the way down to 4 1/2” can be accepted if the production forecast is high enough. In the following example the final section has been scaled down to 5 1/2".

5.2.2.1Example of a slender production well

Here we will look at a slender production well design, the design is presented in figure 5.11. In the design there is added one more casing point than for conventional drilling, which normally has 5 casing/liners, this design has 6. The extra casing point is added so that if unexpected problems that leads to the need of setting an extra casing is faced, we will still be able to drill the well to target depth. Or if the conventional well design is not able to reach target depth due to difficult mud windows in the formation, which leads to the use of an extra casing/liner. The riser used in this example has an ID of 12 1/2", this is necessary because we want to set an 8 5/8 x 6 5/8” casing before the 4 1/2" liner is set in the productive zone. Setting the 8 5/8 x 6 5/8” casing will make the well safer, because without this casing, the 14” casing and the 10 3/4" and 8 5/8” liner will be the only barrier between the formation and the well bore. When setting the 8 5/8 x 6 5/8” casing, this will give an extra string between the well and the formation. We want to have this string in the well before drilling into the high pressured reservoir. The reason that the string crosses over to 8 5/8” above the top of the 8 5/8” liner is to make space for the DHSV. After the 4 1/2" liner is set, a 5 1/2" tie-back production string with a crossover to 4 1/2" string is attached to the 4 1/2" liner.

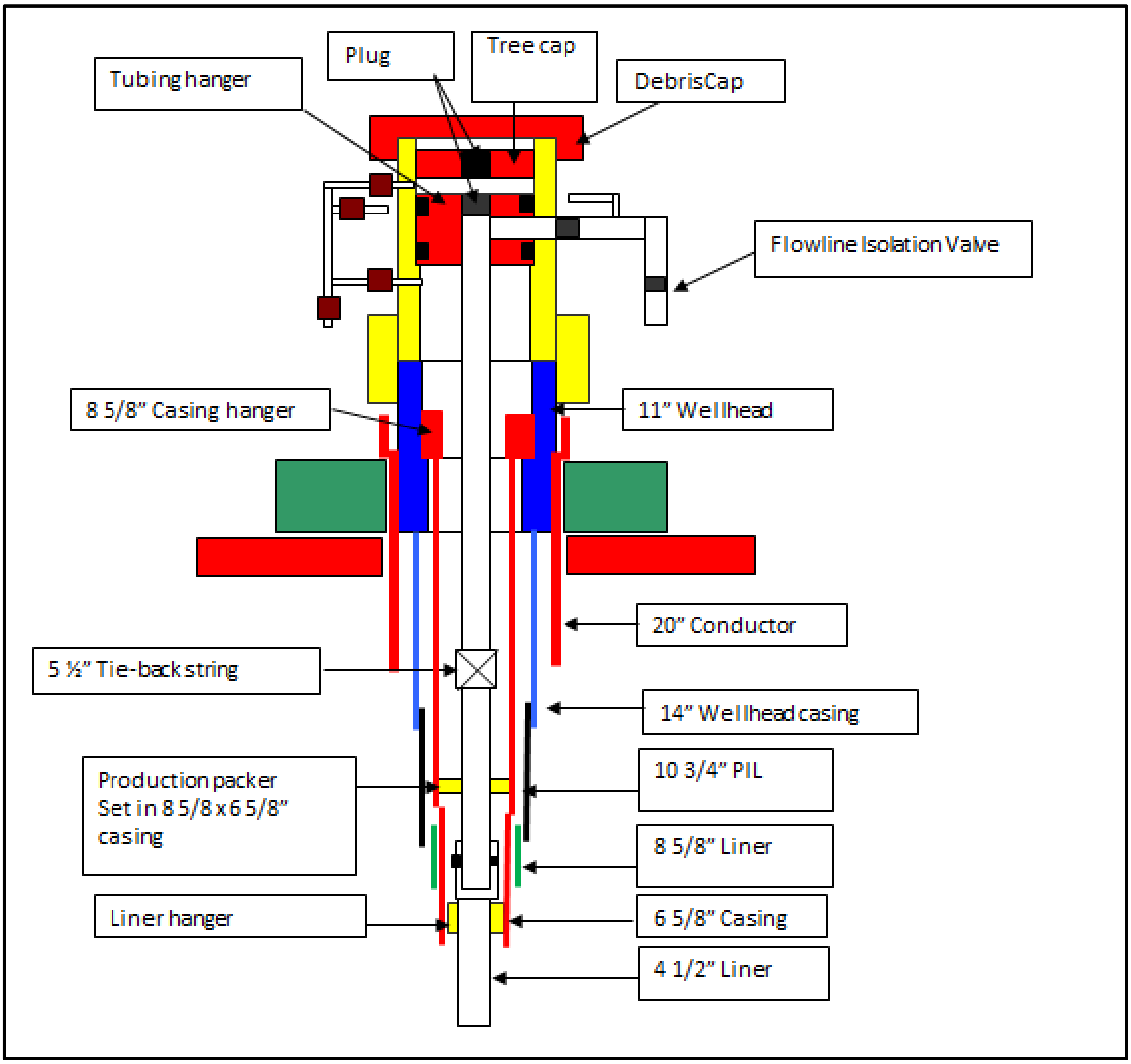

Figure 5.11: Example of a slender production well (Sangesland 2012).

In the slender production well, the production string is set as a liner with a tie-back. Another solution would have been to run the string as a long string all the way up to surface in one run. By using a liner with a tie-back the cementing will be easier due to reduced contamination of the cement because the cement travels through a smaller surface when cementing a liner, this is shown in figure 5.12. The area inside the drill pipe used for cementing the liner is much less than the area inside the casing, this means that the cement will be less exposed to mud and drill cuttings when cementing a liner. Also since the liner can be rotated, the cement job will be better, since a long string cannot be rotated. The ECD during cementing will be higher if a long string is used. The Macondo well can be used as an example of this, in this well a long string was chosen, when a liner with a tie-back would have given a better cement job. This was not the direct cause of the blowout, but it increased the risk of cement failure (Chief Counsel's Report 2011).

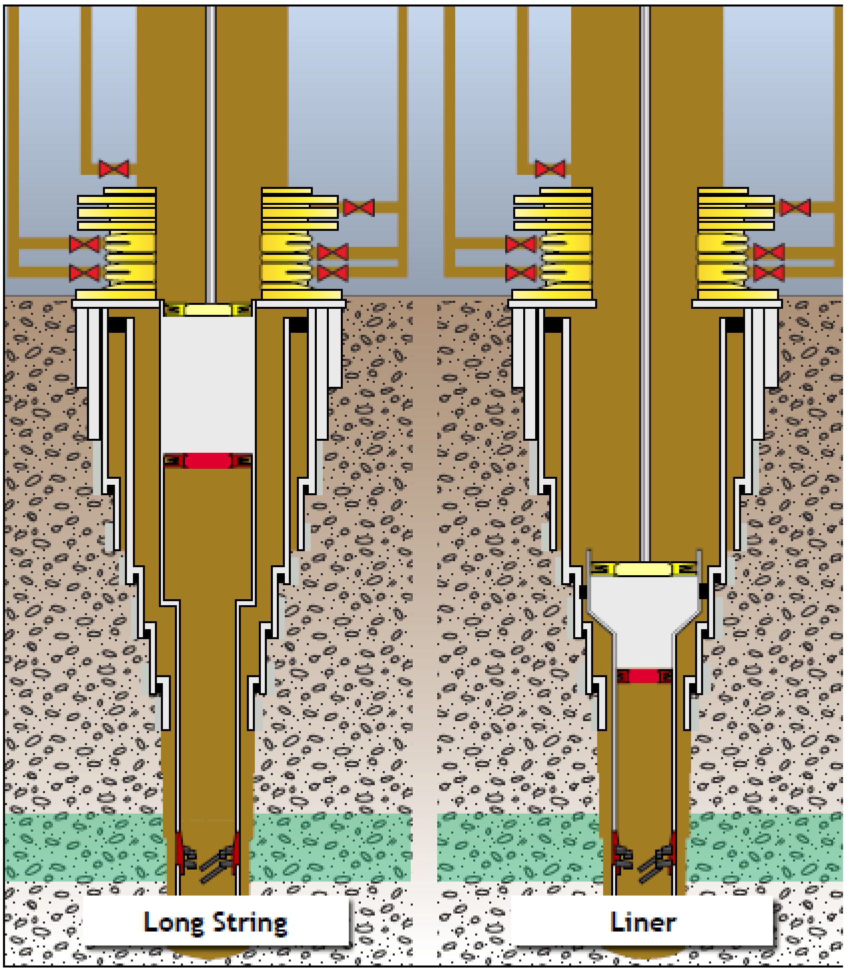

Figure 5.12: Cementing a long string versus cementing a liner (Chief Counsel's Report 2011).

Using a liner with a tie-back also has disadvantages, since it creates a trapped annulus above the liner hanger. This can cause annular pressure build up from heated hydrocarbon flow in the well that causes expansion of fluid in the trapped annulus, this is explained in figure 5.13. APB can be avoided by using rupture disks in the casing strings, this is small disks in the casings that has a pressure rating just below the pressure rating of the casing. If the pressure builds up, these disks will blow just before the casing fails, and thereby burst or collapse of the casing is avoided. Another solution is to use compressible fluid in the annular space, this will allow the fluid to be heated without expanding too much.

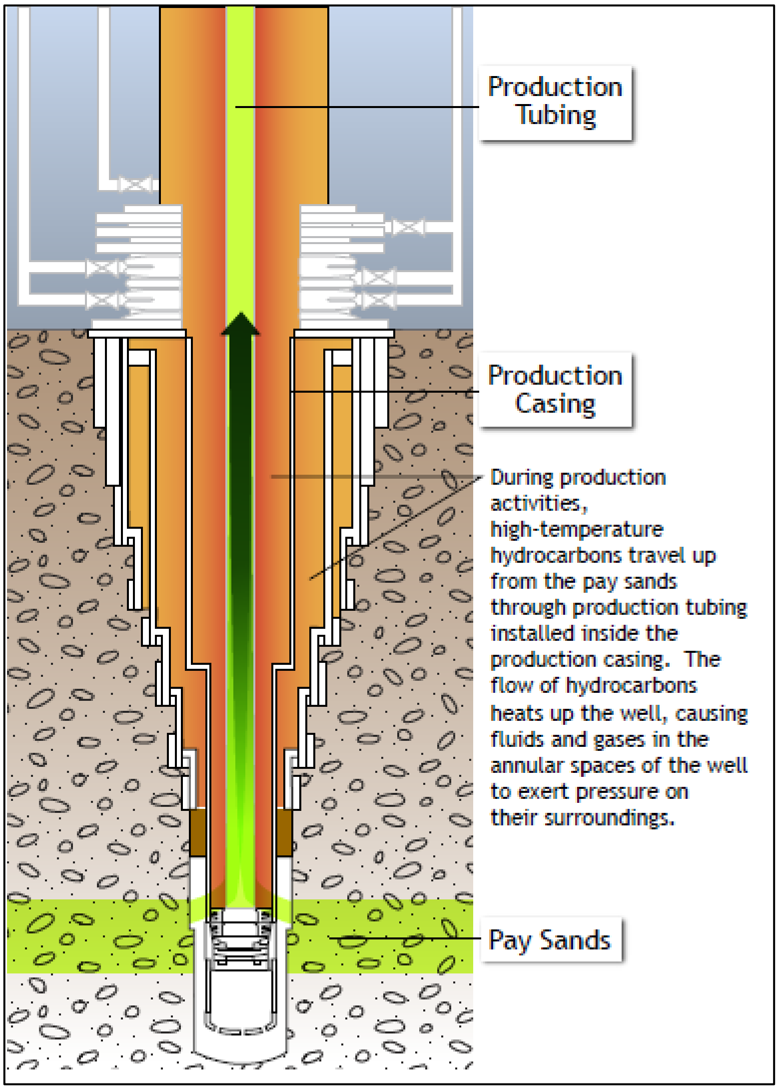

Figure 5.13: Annular pressure build up (Chief Counsel's Report 2011).

While drilling, the primary well barrier is the fluid column in the well, while secondary barriers are: casing cement, casing, wellhead, riser and BOP. During production, the primary well barriers are: Production packer, completion string and SCSSV. The secondary well barriers during production are: casing cement, casing, wellhead, tubing hanger, annulus access line and valve, and the production tree (Norsok D-010, 2004). Figure 5.14 presents the difference in barriers to flow from using a liner, liner with tie-back or a long string. We see that using a liner or a long string adds two extra barriers to annular flow. While using a liner with tie-back provides four extra barriers to annular flow.

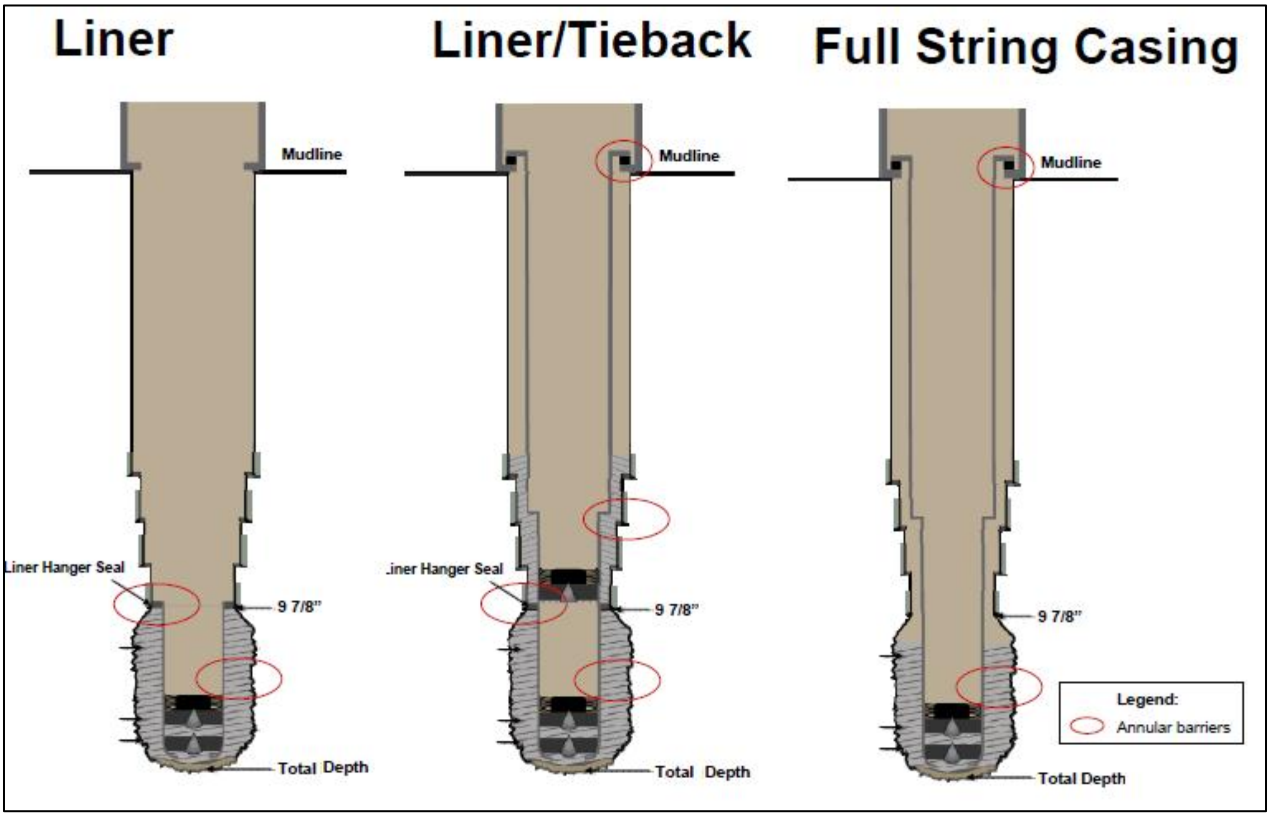

Figure 5.14: Barriers to annular flow using a liner, liner with tie-back or a long string (figure derived from Roth T. 2010).

To design the slender production well, we will use the same pressure data as for the first exploration well example, with a water depth of 380 m RKB, but here we will add an extra casing point to be able to cope with unexpected problems while drilling. The mud weights and drilling depths are presented in figure 5.15, and table 5.21. The 8 5/8 x 6 5/8" casing crosses over to 8 5/8" at 2320 m RKB, just above the 10 3/4" liner shoe.

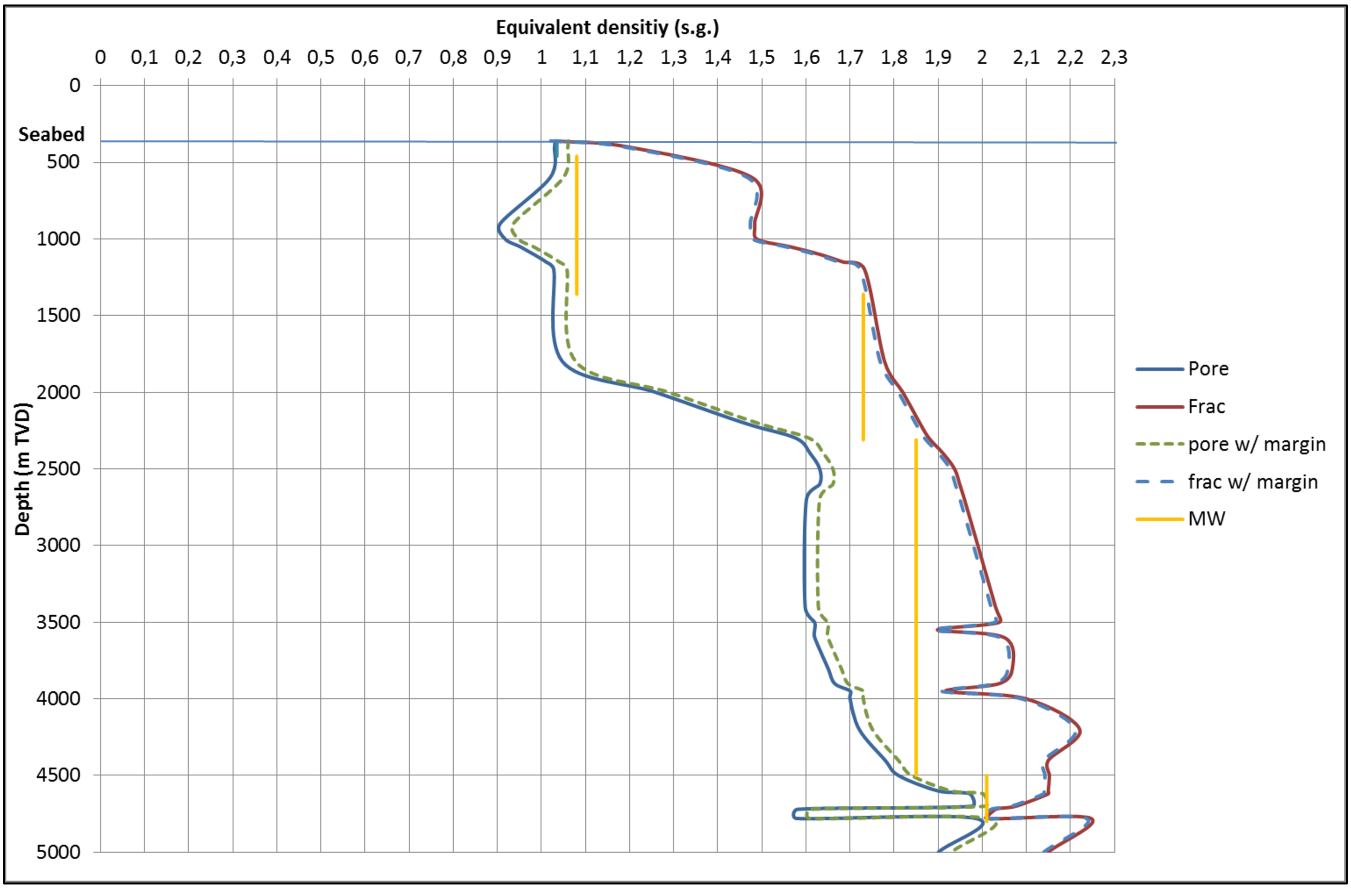

Figure 5.15: Drilling depths and mud weights for drilling the slender production well.

Table 5.21: Sizes and depths for the slender production well.

Section drilled [inches]	Casing/liner size [inches]	Target depth of section [m RKB]	Length of casing/liner [m]
22”	20” casing	480	100
17 1/2”	14” casing	1380	1000
8 1/2 x 12 1/4" UR	10 3/4” PIL	2330	950
7 7/8 x 9 1/2" UR	8 5/8” liner	3520	1190
5 7/8 x 7 5/8" UR	8 5/8 x 6 5/8” casing	4520	1940/2200*
5 1/2”	4 1/2" liner	4820	300

**The length of the 8 5/8 x 6 5/8” casing has two values, the first value is the length of the 8 5/8” part, and the second value is the length of the 6 5/8” casing.*

The casing design is done by using equations from chapter 3. The worst case well pressures for burst and collapse are plotted in figure 5.16. We know that the burst pressure increases as we go up the well, so the worst case burst pressure are found at the top of each casing/liner. To ensure that the well is safe to drill, we assume that all casings and liners will be exposed to the reservoir pressure of 932 bar when selecting casings and liners for the well, even though the 8 5/8 x 6 5/8" liner will isolate the above casings and liners before drilling into the reservoir. From the figure we have to check where the worst case collapse pressures are found for each casing, by looking at the difference between the well pressure for collapse and the pore pressure curve. We then find that for the worst case collapse pressure are found at the bottom of all casings except for the 8 5/8" liner, where the worst case collapse pressure is found at about 2500 m, this was found by looking at figure 5.15. At 2500 m the collapse pressure was calculated to 287 bars. The worst case burst and collapse pressures are presented in table 5.22.

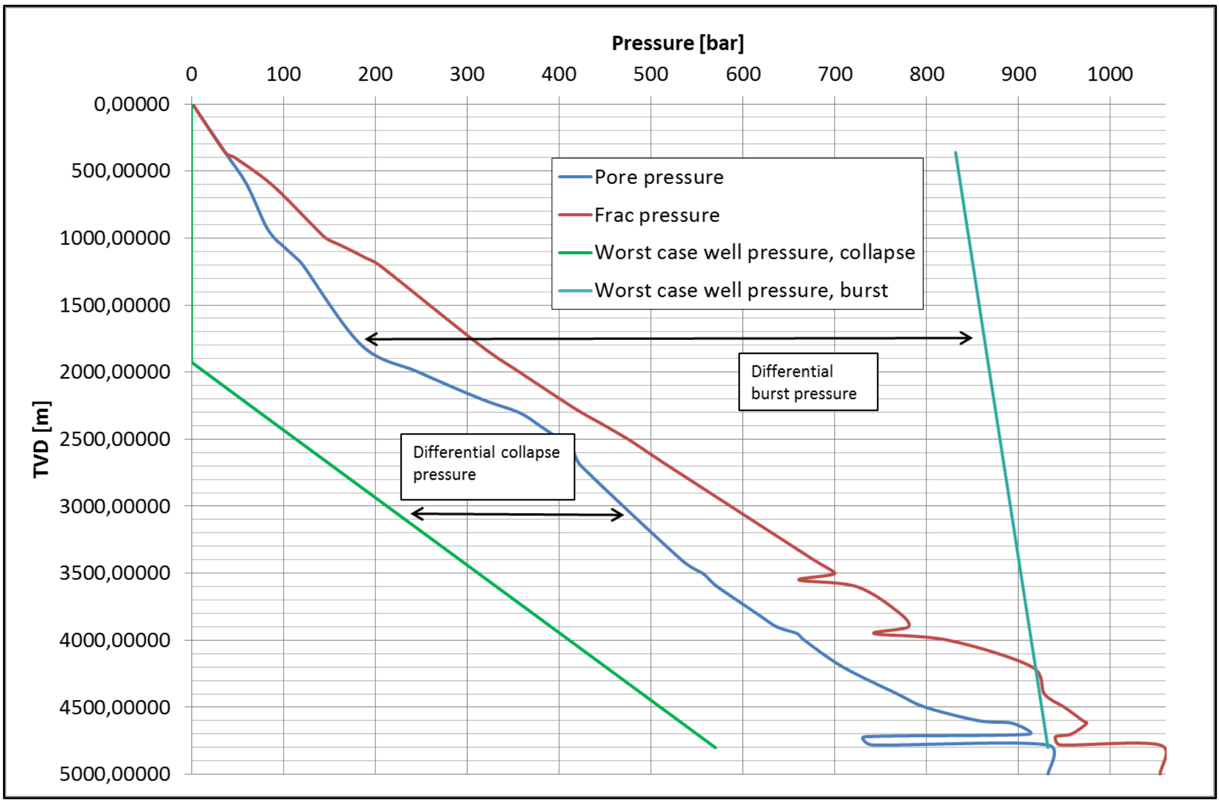

Figure 5.16: Worst case well pressures, plotted versus depth.

Table 5.22: Worst case burst and collapse pressures including and excluding SF for the slender production well.

Casing/liner	Collapse pressure without SF [bar]	Collapse pressure with SF [bar]	Burst pressure without SF [bar]	Burst pressure with SF [bar]
14” casing	159	191	795	954
10 3/4” liner	281	337	695	833
8 5/8” liner	287	344	520	624
*8 5/8 x 6 5/8” liner	281/292	337/350	795/520	954/624
4 1/2” liner	366	439	126	151

**There are two values for the burst and collapse pressures in the 8 5/8 x 6 5/8” casing, this is due to that this casing has two different diameters. The first value is for the 8 5/8” part and the last value is for the 6 5/8” part.*

Now that we know the worst case pressure that the casings and liners will be exposed to, we can find the casings we need in the well to withstand the worst case pressures. The properties of the selected casings and liners are presented in table 5.23, and the casing properties are taken from Vallourec & Mannesmann tubes, and VAM Book. The 14” casing have a SF of 1,15, which is sufficient since it is over 1,1.

Table 5.23: Casing/liner properties for the production well.

Casing/liner OD [Inches]	14” casing	10 3/4” liner	8 5/8” liner	*8 5/8 x 6 5/8” casing	4 1/2" liner
Grade	Q125 HC	Q125	T95 E	Q125 HCE/ T95 E	N80
Weight [lb/ft]	120,00	65,70	40,00	44,00/24,00	12,60
Wall thickness [inches]	0,850	0,595	0,450	0,500/0,352	0,271
Drift [Inches]	12,113	9,404	7,600	7,500/5,796	3,833
Coupling ID [inches]	12,538	9,561	7,681	7,572/5,839	3,876
Coupling OD [inches]	15,146	11,002	8,767	8,809/7,191	4,906
Collapse resistance [bar]	727	546	415	640/435	517
SF collapse	4,57	1,94	1,45	2,28/1,49	1,41
Burst resistance [bar]	916	835	630	945/641	581
SF burst	1,15	1,20	1,21	1,19/1,23	4,61

**There are two values for the properties for the 8 5/8 x 6 5/8” casing, this is due to that this casing has two different diameters. The first value is for the 8 5/8” part and the last value is for the 6 5/8” part.*

Now we can calculate the clearances between the casing/liner set and the previous casing/liner by taking the drift diameter of the previous casing minus the coupling OD for the next casing/liner and divide the answer by two. The clearance between the 20” casing and the 11 3/4” casing will not be a problem and is therefore not included in the calculations.

The clearance between the casings/liners is:

- Between the 14” casing and the 10 3/4” liner: **0,56” = 1,42 cm**
- Between the 10 3/4” liner and the 8 5/8” liner: **0,32” = 0,81 cm**
- Between the 10 3/4” liner and the 8 5/8” casing: **0,30” = 0,76 cm**
- Between the 8 5/8” liner and the 6 5/8” casing: **0,20” = 0,52 cm**
- Between the 6 5/8” casing and the 4 1/2" liner: **0,45” = 1,13 cm**

After controlling the OD of the coupling for the casings with the drift diameter of the previous casing, we see that all the casings are possible to get down through the previous casings/liners that are set. This means that the design is possible to construct in regards of the casing design. The design is possible since the clearances are above the minimum radial clearance for the use of close clearance liners which are 1/8” = 0,125” (Howelett et al. 2006).

The next step now is to find the pressure losses from drilling the well. All calculations are done in Mud calc, and the results are presented in table 5.24. The sections from 22” to 9 1/2” use a 70 m DC, and the sections from 7 5/8” and down to TD of the well uses a 30 m BHA. The drill strings used to drill the 22” and 17 1/2” section have an OD of 5” and an ID of 4,276”, while the drill string used in the remaining sections have an OD of 3,5” and an ID of 2,764”.

Since the riser has a larger ID than in the previous examples, the minimum mud velocity will be inside the riser during drilling of the last section. The velocity inside the riser will not be any problem if we boost the riser with mud. This means that we inject extra mud in the lower part of the riser to increase the flow rate inside the riser.

Table 5.24: Pressure losses for drilling the production well.

Section drilled	22”	17 1/2"	8 1/2 x 12 1/4" UR	7 7/8 x 9 1/2" UR	5 7/8 x 7 5/8” UR	5 1/2"
Casing/liner set	20” casing	14” casing	10 3/4" liner	8 5/8” liner	8 5/8 x 6 5/8” casing	4 1/2” liner
Length of section [m]	100	1000	950	1190	1000	300
MW [s.g.]	1,035	1,08	1,73	1,85	1,85	2,01
ECD at top of section [s.g.]	1,035	1,081	1,735	1,856	1,864	2,040
ECD at bottom of section [s.g.]	1,036	1,082	1,735	1,857	1,868	2,053
Pressure loss DP [bar]	71,5	40,5	167,7	302,3	333,8	123,8
Pressure loss annulus [bar]	0,0	0,3	1,1	2,3	8,1	16,0
Pressure loss bit [bar]	45,1	42,4	14,8	57,4	50,0	7,6
*v_{min} [m/s]	0,28	0,30	0,32	0,34	0,34	0,52
Flow rate [l/min]	4000	3000	1400	1500	1400	700
Pump pressure [bar]	189	132	209	391	419	163

**The minimum velocity does not include the riser, the velocity in the riser is 0,16, but by injecting mud into the lower part of the riser, the velocity in the riser will increase and will not be any problem.*

Now all calculations are done, and the ECD is plotted together with the mud weight in figure 5.17. We see that the ECD is almost the same as the mud weight for the upper sections, this is due to the low circulation rate in the well.

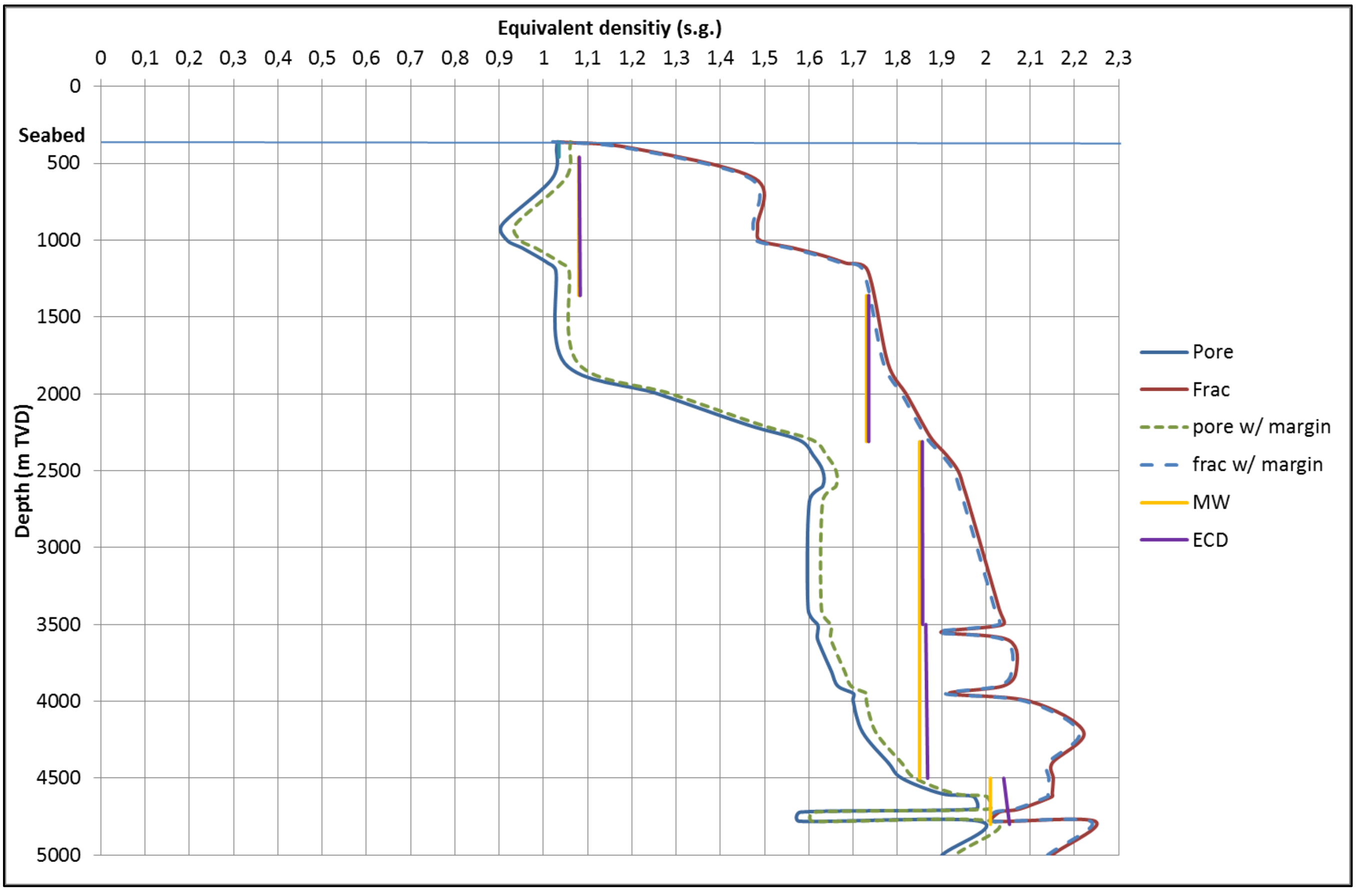

Figure 5.17: Mud weights and ECD for drilling the slender production well.

We see from the figure that the ECD when drilling the last section will be too high to drill the section conventionally because we are not able to keep the mud weight and ECD inside the mud window. Techniques such as MPD can be used to drill the section safely to TD at 4820 m RKB.

6. Savings from drilling slender wells

By using the same pressure data and drilling depths as for the previous examples, we can compare a typical conventional well against the three proposed slender well designs. The amount of drill cuttings, mud and steel can be calculated for the different designs to see the actual savings. The base case, which is the conventional design, is presented in table 6.1. The water depth is 380 m RKB.

Table 6.1: Lengths and diameters for the conventional well design.

Section drilled conventional	Casing/liner size	Target depth of section (m RKB)	Length of section (m)	Length of casing/liner (m)
36” hole	30”	480	100	100
26” hole	20”	1380	900	1000
17 1/2” hole	13 3/8”	2330	950	1950
12 1/4" hole	9 5/8”	4520	2190	4140
8 1/2” hole	7” (liner)	4820	300	300

6.1 Savings in drill cuttings amount

Here we will look at the amount of drill cuttings generated from drilling the different well design. By reducing the amount of drill cuttings we will need less storage space on the rig, and there will be less drill cuttings to handle and to transport. Equation 6.1 is used to calculate the volume of drill cuttings in a section.

$$V_{cuttings} = \pi \times \left(\frac{d \times 0,0254}{2}\right)^2 \times l \qquad (6.1)$$

Here $V_{cuttings}$ is the volume of drill cuttings given in m^3, d is the diameter of the open hole given in inches and l is the length of the section given in meters.

The amount of drill cuttings generated from drilling the well conventionally is presented in table 6.2. We see that the amount of drill cuttings for drilling this specific well is 698,9 m^3 if the well is drilled with a conventional drilling design.

Table 6.2: Drill cuttings generated from drilling the conventional well.

Section drilled conventional	Volume of drill cuttings (m^3)	Target depth of section (m RKB)	Length of section (m)
36” hole	65,7	480	480
26” hole	308,3	1380	900
17 1/2” hole	147,4	3900	950
12 1/4" hole	166,5	4520	2190
8 1/2” hole	11,0	4820	300
Total	**698,9**		

The amount of drill cuttings generated from drilling exploration well I and exploration well II, is the same because the two wells are drilled with the same bit sizes. The amounts of drill cuttings from these wells are presented in table 6.3. Here we see that the total drill cuttings amount from this well is 271,5 m^3. Compared to the conventional design, this is a reduction of 61,1 %.

Table 6.3: Amount of drill cuttings generated from drilling slender exploration well I & II.

Section drilled	Volume of drill cuttings (m^3)	Target depth of section (m RKB)	Length of section (m)
22”	24,5	480	480
14”	89,4	1380	900
8 1/2" x 12 1/4" UR	72,2	3900	950
7 7/8” x 8 1/2" UR	80,2	4520	2190
5 7/8”	5,2	4820	300
Total	**271,5**		
% reduction	**61,1 %**		

The drill cuttings amount from drilling the slender production well is presented in table 6.4. We see that the total amount of drill cuttings is 324,9 m^3. Compared to the conventional design, this is a reduction of 53,5 %.

Table 6.4: Amount of drill cuttings generated from drilling the slender production well.

Section drilled	Volume of drill cuttings (m^3)	Target depth of section (m RKB)	Length of section (m)
22”	24,5	480	480
17 1/2”	139,7	1380	900
8 1/2 x 12 1/4" UR	72,2	2330	950
7 7/8 x 9 1/2" UR	54,4	3520	1190
5 7/8 x 7 5/8" UR	29,5	4520	1000
5 1/2”	4,6	4820	300
Total	**324,9**		
% reduction	**53,5 %**		

6.2 Savings from steel consumption

The conventional design uses mostly casings, while the slender design uses more liners. The use of casings instead of liners means that a lot more steel is needed because the casings goes all the way up to the surface, while the liners only goes up the shoe of the previous casing/liner. This, in addition to the smaller diameter of the sections, reduces the amount of steel significantly if a slender well design is used. Here we will have a look at the volume of steel from the casings and liners used in the wells. The steel volume of a casing/liner is calculated using equation 6.2.

$$V_{steel} = \pi \times d \times l \times t \times (0{,}0254)^2 \qquad (6.2)$$

In this equation, V_{steel} is the volume of steel given in m^3, d is the diameter of the string given in inches, l is the length of the string given in meters and t is the wall thickness of the casing/liner given in inches.

The volume of the steel used for drilling the well with the conventional design is presented in table 6.5. A wall thickness of 0,625” is used for the 30” conductor, the rest of the wall thicknesses are taken from table 5.6.

Table 6.5: Steel amount for casings and liner in the conventional well.

Casing/liner size	Length of string (m)	Wall thickness	Volume of steel (m^3)
30”	100	0,625	3,8
20”	1000	0,635	25,7
13 3/8”	1950	0,550	29,1
9 5/8”	4140	0,435	35,1
*7” (liner)	300	0,362	1,5
Total			**95,2**

**The 7” liner is not used for exploration wells and is therefore not included in the comparing versus the slender exploration wells. The total volume of steel for the conventional exploration well will therefore be 93,7 m^3.*

We see that for this example 95,2 m^3 of steel is used for casings and liner. The numbers for this well can now be compared against different slender well designs. When comparing the steel volume against the exploration well, the 7” liner in the conventional well is not included in the calculations because the conventional exploration wells use an open hole in the last section. The volume for the 7” liner which is 1,5 m^3 m^3 is therefore subtracted from the total volume, and the volume for the conventional exploration well is therefore 93,7 m^3. First we calculate the volume of steel for exploration well I. The wall thickness for the 20” casing is chosen to be 0,500” for both sleder exploration wells, and the rest of the wall thicknesses are taken from table 5.12. The steel volume needed for drilling exploration well I is presented in table 6.6.

Table 6.6: Steel volume of casings and liner for exploration well I.

Casing/liner size	Length of string (m)	Wall thickness	Volume of steel (m^3)
20” casing	100	0,500	2,0
11 3/4” casing	1000	0,656	15,7
9 5/8” PIL	950	0,545	10,1
7” liner	2190	0,362	11,2
Total			**38,9**
% reduction			**58,5**

Next is the slender production well, the steel volume for this well is presented in table 6.7. The wall thickness of the 20” conductor casing is chosen to be 0,500”, this is the same as for the slender exploration wells. The rest of the wall thicknesses are taken from table 5.23.

Table 6.7: Steel volume of casings and liners for the production well.

Casing/liner size	Length of string (m)	Wall thickness	Volume of steel (m^3)
20" casing	100	0,500	2,0
14" casing	1000	0,850	24,1
10 3/4" PIL	950	0,595	12,3
8 5/8" liner	1190	0,450	9,4
8 5/8 x 6 5/8" casing	1940/2200*	0,500/0,352*	27,4
4 1/2" liner	300	0,271	0,9
Total			**76,1**
% reduction			**20,1 %**

**There are two values for the properties for the 8 5/8 x 6 5/8" casing, this is due to that this casing has two different diameters. The first value is for the 8 5/8" part and the last value is for the 6 5/8" part.*

6.3 Savings in mud amount

The amount of mud needed can be significantly reduced only by reducing the size of the riser. Equation 6.3 is used to calculate the volume of mud in the well, when drilling the last section, because this will be the section which requires the largest amount of mud.

$$V_{mud} = V_{riser} + V_1 + V_2 + \ldots + V_n \qquad (6.3)$$

Where V_{mud} is the total amount of mud needed in the well, V_{riser} is the amount of mud in the riser and V_1 up to V_n is the volume of each section of casings/liners or open hole. V_n is given by equation 6.4, in this equation the ID is given in inches, and l is the length of the section. The drilling of the two first sections is not included in the calculations because they are drilled riser less and with sea water.

$$V_n = \frac{\pi}{4} \times (ID \times 0{,}0254)^2 \times l \qquad (6.4)$$

The amount of mud needed for drilling the conventional well, is calculated and presented in table 6.8. After finding the amount of mud required for drilling each section we can find out which section requires the most mud, and this will be our mud volume. Length of the riser is 380 m, and the riser has an ID of 19". The ID of the casings and liners used is the OD minus 2 x wall thickness of the string.

Table 6.8: Volume of mud needed for drilling the conventional well.

Section drilled	Mud filled sections	Volume of mud needed in the well (m^3)
17 1/2" hole	380 m of riser (ID = 19") + 1000m of 20" casing (ID = 18,730") + 950 m of 17 1/2" OH	69,5 + 177,8 + 147,4 **Total: 394,7**
12 1/4" hole	380 m of riser (ID = 19") + 1950 m of 13 3/8" casing (ID = 12,275") + 2190 m of 12 1/4" OH	69,5 + 148,9 + 166,5 **Total: 384,9**
8 1/2" hole	380 m of riser (ID = 19") + 4140 m of 9 5/8" casing (ID = 8,755") + 300 m of 8 1/2" OH	69,5 + 160,8 + 11,0 **Total: 241,3**

From table 6.8, we see that the section that requires the biggest amount of mud is drilling of the 17 1/2" section, with 394,7 m^3 of mud. In this example the amount of mud needed is reduced the further down we go, this is due to the large diameters in the upper sections. The large sections are eliminated when a new and smaller casing is set for the next section.

Now we will use the conventional design as our base case and compare the mud amount of this well versus the mud amount needed for the slender wells. The mud volume needed for drilling exploration well I is presented in table 6.9. Here we find the highest mud volume when drilling the 7 7/8 x 8 1/2" section, with a total mud volume of 184,8 m^3. This is a reduction of 53,2 % compared to the conventional well. Drilling exploration well II will require nearly exactly the same amount of mud as exploration well I, the only difference of the two wells is an extra 0,05" of wall thickness that is added to the 9 5/8" casing in exploration well II.

Table 6.9: Mud volumes needed for drilling exploration well I.

Section drilled	Mud filled sections	Volume of mud needed in the well (m^3)
8 1/2" x 12 1/4" UR	380 m of riser (ID = 8,625") + 1000m of 11 3/4" casing (ID = 10,438") + 950 m of 12 1/4" OH	14,3 + 55,2 + 72,2 **Total: 141,7**
7 7/8" x 8 1/2" UR	380 m of riser (ID = 8,625") + 1000 m of 11 3/4" casing (ID = 10,438") + 950 m of 9 5/8" liner (ID = 8,535") + 2190 m of 8 1/2" OH	14,3 + 55,2 + 35,1 + 80,2 **Total: 184,8**
5 7/8"	380 m of riser (ID = 8,625") + 1000 m of 11 3/4" casing (ID = 10,438") + 950 m of 9 5/8" liner (ID = 8,535") + 2190 m of 7" liner (ID = 6,276") + 300 m of 5 7/8" OH	14,3 + 55,2 + 35,1 + 43,7 + 5,2 **Total: 153,5**

Now we will look at the mud volume needed for drilling the slender production well. The volumes are presented in table 6.10. Here we see that the section that requires most mud is the 5 7/8 x 7 5/8" with 216,3 m^3. This is a reduction of 45,2 % compared to the conventional well.

Table 6.10: Mud volumes needed for drilling the slender production well.

Section drilled	Mud filled sections	Volume of mud needed in the well (m^3)
8 1/2 x 12 1/4" UR	380 m of riser (ID = 12,5”) + 1000m of 14” casing (ID = 12,300”) + 950 m of 12 1/4” OH	30,1 + 76,7 + 72,2 **Total: 179,0**
7 7/8 x 9 1/2" UR	380 m of riser (ID = 12,5”) + 1000 m of 14” casing (ID = 12,300”) + 950 m of 10 3/4” liner (ID = 9,560”) + 1190 m of 9 1/2” OH	30,1 + 76,7 + 44,0 + 54,4 **Total: 205,2**
5 7/8 x 7 5/8" UR	380 m of riser (ID = 12,5”) + 1000 m of 14” casing (ID = 12,300”) + 950 m of 10 3/4” liner (ID = 9,560”) + 1190 m of 8 5/8” liner (ID = 7,725”) + 1000 m of 7 5/8" OH	30,1 + 76,7 + 44,0 + 36,0 + 29,5 **Total: 216,3**
5 1/2”	380 m of riser (ID = 12,5”) + 1940 m of 8 5/8” casing (ID = 7,625”) + 2200 m of 6 5/8” casing (ID = 5,921”) + 300 m of 5 7/8" OH	30,1 + 57,2 + 39,1 + 5,2 **Total: 131,6**

7. Discussion

If unexpected problems are faced during the drilling of the wells, expandable liners can be a solution to still be able to drill the well to TD. By using an expandable liner the well can be drilled with an extra casing point without losing to much/any hole size. Even if this cannot fix the problem, and the well is lost this can be acceptable due to the fact that 3 – 4 slender wells can be drilled at the cost of 2 conventional wells (strand 1994). The risk of not reaching TD with the desired final hole size will of course be higher due to the reduced diameter of the top hole section.

If the mud velocities in the well are too low, the flow rates can be increased without causing any problems, since the pump pressures are low compared to the capacity of the mud pumps.

Slender exploration well II has a reservoir pressure of 15 000 psi, in the attempt of designing a 15 000 psi well. This seems to be possible by the use of expandable reamers, since both the radial clearances and pressure losses for drilling are practicable. We know that the casings, liners, wellhead and BOP used for slender well design is available with a pressure rating of 15 000 psi. One thing that can be discussed is the pressure integrity of the liner hanger, TIW XPAK claims that their liner hanger has a pressure rating that is equal to the pressure rating of the liner itself, but can we trust that it can withstand 15 000 psi?

By reducing the size of the casings and liners in the well, the wall thickness can also be reduced. This is due to that smaller diameter pipes needs less wall thickness to be able to withstand the pressures, the reduction of wall thickness is due to the reduced inner area of the string. The less the inner area of the casing, the less wall force is applied to the casing wall. This can be explained by equation 7.1.

$$F = P \times A \qquad (7.1)$$

In this equation, F is the force applied to the casing wall, P is the pressure applied on the casing and A is the area of the casing. We see that if A is reduced, F which is the force applied to the casing is also reduced, and thereby the wall thickness can be reduced and the casing can still take the pressure.

An 11” wellhead and BOP stack has been selected for designing the slender well designs, this is the smallest possible wellhead and BOP we can use, and will give the lowest possible material costs for the well. The 11” wellhead allows us to reach TD with a sufficient hole diameter, and has enough casing hanging point to complete the well.

After checking the radial clearances for the casings and liners it seems that both the slender exploration and production designs are possible by the use of close clearance liners. The smallest radial clearance that were calculated was 0,20” this is above the minimum radial clearance for the use of close clearance liners which is 1/8” = 0,125” (Howelett et al. 2006). Since also the clearance between the casings and the drill bit is small while running in and out of hole, we have to run in and out of hole slowly and carefully to avoid swab and surge pressures where there are small clearances.

For the casing design it is the surface casing that has to withstand the highest burst pressure, if the regular surface casing is too weak it can be special ordered with a larger diameter. This will be possible to fit in the well since there is plenty of room between the conductor casing and the surface casing, meaning that the surface casing can have a larger wall thickness outwards. In this way the ID of the string will not be reduced.

The use of the 8 5/8 x 6 5/8” casing string instead of a liner in the slender production well means that more steel is needed in the well since a casing is longer than a liner. Setting the string will also require more time. However the casing string makes the well safer due to the extra barrier in the well. If only liners are used in the well, the liner and the cementing of the liner would have been the only barrier between the well bore and the formation. Wear of the liners from the drill string and mud circulation could have weakened the liners. Also effects of temperature and corrosion can have a weakening effect on the strings.

Setting a liner with a tie-back instead of setting a long string as production string will make the cementation easier and safer since the liner can be rotated and there is less contamination of cement when cementing a liner. However there can be problems with annular pressure build-up since a tie-back creates a trapped annulus, but this can be solved using rupture disks or compressible fluid in the trapped areas.

When comparing the exploration well and the production well versus the conventional well we will look at exploration well I and the slender production well. These three wells are drilled with the same water depth and the same pressure data in the well.

There is a lot of money and time to save by drilling slender wells. Looking at the amount of drill cuttings generated from drilling the wells we see from table 7.1 that the drill cuttings volume are reduced by 61,1 % for the exploration well and 53,5 % for the production well. This means that there will be less drill cuttings to handle and to store on the rig, and also the transportation is reduced.

Table 7.1: Reduction in drill cuttings volume from drilling slender wells.

Well	Amount of drill cuttings [m^3]	Reduction in drill cuttings volume [%]
Conventional	698,9	-
Exploration	271,5	61,1
Production	324,9	53,5

The volume of steel needed in the well is also reduced significantly by drilling slender wells. If we compare the slender exploration well and the slender production well versus the conventional well, we see that the steel volume for slender exploration well I is reduced by 59,1 %. For the slender production well the reduction of steel volume needed is 20,1 %. The savings in steel volume is presented in table 7.2. The reduction of the steel volume from the exploration well is significantly higher than the reduction from the production well. This is mostly due to the use of 6 5/8 x 8 5/8" casing which is set inside the liners to have more pressure barriers, to ensure that the well is designed safely.

Table 7.2: Reduction in steel volume from drilling slender wells.

Well	Amount of drill cuttings [m^3]	Reduction in drill cuttings volume [%]
Conventional	95,2	-
Exploration	38,9	59,1
Production	76,1	20,1

The amount of mud is significantly reduced by drilling slender wells, the smaller bore riser contributes highly to this reduction. In table 7.3 we have presented the savings in mud volume from drilling slender wells versus drilling the well conventionally. Here we see that the mud volume is reduced by 53,2 % for drilling slender exploration well I, and a reduction of 45,2 % is achieved from drilling the slender production well.

Table 7.3: Reduction in mud volume from drilling slender wells.

Well	Amount of drill cuttings [m^3]	Reduction in drill cuttings volume [%]
Conventional	394,7	-
Exploration	184,8	53,2
Production	216,3	45,2

All these savings together will lead to the possibility of using a smaller rig for drilling the wells. This is due to the reduction in storage volumes on the rig, and the use of smaller equipment. Since the day rate of hiring a drilling rig is high, there are huge amounts of money to save by drilling slender wells.

8. Conclusion

- Drilling slender wells will reduce the amount of drill cuttings with about 50 – 60 %, depending on the well design.

- The volume of steel needed for casings and liners is reduced with up to 60 % if slender well drilling is applied.

- The mud volume is reduced by about 50 %, this volume will depend on the well design and the riser size and length.

- Using slender well technology will reduce the storage need on the rig, leading to the use of a smaller rig which will save a lot of money. In addition to using a smaller rig, also the transportation is reduced.

- The wells are drilled more safely due to the use of smaller equipment which is easier and safer to handle. This is important since the oil companies have a high focus on HSE.

- It is possible to design slender wells in high pressure fields with narrow mud windows.

- It seems to be possible to design a slender 15 000 psi well, using pressure data from a HPHT field.

- If unexpected problems are faced, slender wells still ensure that target depth can be reached by the use of an extra casing point. Expandable liners can be used without losing too much/any hole size.

- The ECD from drilling slender wells are low due to the low circulation rate in the well bore.

9. Future Work

- Investigate the potential cost savings by drilling slender wells by finding rig, mud, steel, transportation costs etc.

- Investigate potential increase in ROP by drilling slender wells.

- Perform study on conventional and expandable liner hangers for 15 000 psi.

- Investigate the effect of increasing the pressure rating from 10K to 15K.

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Appendix I: Pressure data

Depth [m TVD]	Pore pressure [bar]	Fracture pressure [bar]	Margin [bar]
0	1	1	0
360	36	36	0
400	40	47	7
600	60	87	27
900	80	131	51
1000	90	146	56
1050	98	161	63
1100	106	176	70
1150	114	190	76
1200	121	204	83
1800	185	314	129
2000	247	357	110
2200	315	401	86
2300	356	424	68
2400	379	450	71
2500	400	475	75
2600	416	497	81
2700	424	519	95
3400	533	677	144
3500	556	700	144
3550	564	661	97
3600	572	724	152
3800	615	771	156
3900	637	780	143
3950	659	743	84
4000	667	824	157
4200	709	915	206
4400	768	928	160
4500	799	950	151
4600	857	970	113
4620	894	974	80
4700	911	957	46
4720	732	940	208
4780	740	945	205
4781	932	1054	122
5000	932	1054	122