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A Study in Limiting Factors for Extended Reach Drilling of Highly Deviated Wells in Deep Waters

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I hereby declare that this Master of Science Thesis is made independently and completed in accordance to all the rules and regulations at NTNU.

Samandrag

Boring på djupt vatn krev meir avansert teknologi etter som felt på stadig større djup vert oppdaga. ”Managed Pressure Drilling” og ”Dual Gradient Drilling” er to variantar som tilbyr ulike metodar for å gjere det enklare og navigere i det tronge poretrykk og brot gradient vindauge ein har under slike operasjonar. Saman med andre boring og utviklingssystem er dei introdusert som moglege løysingar på utfordringane assosiert med boring på djupt vatn.

Industrien ser på moglegheitene for å bore høgavviks brønnar på djupt vatn, då dette kan hjelpe til med og auke utvinninga av olje. Før slike operasjonar eventuelt vert gjennomførde er det vanleg å køyre ei simulering slik ein finn ut kva faktorar som vil avgrense maksimal brønnbane. Softwaren WELLPLAN™ vert brukt til å finne ut kor langt ein teoretisk sett kan bore i horisontal og vertikal retning, basert på data frå ei brønnbane i Mexicogulfen. Ut frå simuleringar finn vi at det er styrken på borerøra som hindrar oss i og bore enda lenger. To ulike riggar vert brukt som kandidatar for og gjennomføre operasjonen, og vi ser at ingen av dei er i nærleiken av maksimal pumpekapasitet og dreiemoment, so begge kandidatar er gode alternativ for operasjonen.

ECD (equivalent circulating density) ville vore faktoren som avgrensa kor langt det er mogleg og bore, men vi kan enkelt kompensere for problema knytte til ECD dersom vi kan kontrollere trykkprofilen. Dette vil ikkje vere mogleg med konvensjonell boring, då det vil krevje meir casing, som resulterar i mindre radius på boreholet, enn kva DGD gjer. Frå analysen av dei ulike bore parameterane ser vi kor viktig det er med tilgong til data frå tilsvarande brønnbaner, då ein reduksjon i friksjonsfaktor har potensiale til å auke brønnbane lengda, og korleis eit alvorleg avvik kan gjere at vi aldri når ynskja djup.

Abstract

Drilling in deep water is requiring more advanced technology as fields at greater depths are being discovered. Managed Pressure Drilling and Dual Gradient Drilling are both offering different techniques for navigating through the narrow pore pressure and fracture gradient window during an operation. Along with different drilling and development systems they are introduced as possible solutions to many of the challenges associated with deepwater drilling.

The industry is looking into the possibility of doing highly deviated extended reach wells in deep water environments. Before doing so different simulations are done to investigate which factors will limit the maximum well trajectory and to figure out of far it is theoretically possible to drill in horizontal and vertical direction. With the help of the WELLPLAN™ software a reservoir located in the Gulf of Mexico is chosen as a well candidate to run simulations on. Case study shows that for both directional extensions buckling of the drillpipe is what keeps us from drilling further. In terms of torque and pump capacity both rig candidates used for the study are well within their maximum capacities.

Equivalent circulating density (ECD) would have been the main problem for the case study, but can easily be compensated for assuming we have the potential to control the pressure profile. With conventional drilling we would not be able to handle problems associated with ECD, meaning that DGD or other methods are required. From the sensitivity study we learn the importance of having access to accurate wellbore data, as a reduction in friction factor has the potential to extend the well trajectory even further and a potential dogleg severity would make us unable to reach target depth.

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Introduction

A great deal of the world's undeveloped oil and gas resources are located in deep and ultra deep water, and pose a great challenge for future technology. But it is a necessity to get a hold of these resources as the easily accessible fields are depleting while the world still demand larger amounts of these non renewable resources. In order to do so efficiently the industry must keep evolving and pushing available equipment to its limits to reach greater depths. Drilling in deep water is changing from mainly vertical wells, to highly deviated ones as well. This might help increase recovery factor, but it will most certainly be more challenging. Drilling in this environment will push equipment to its absolute limits, increasing the possibilities for failure and leaving no room for error. The environment will suffer greatly should any accidents occur, just think of the dreadful Macondo incident a few years back. Highlighting potential areas of concern through careful planning will be a main priority.

In this thesis we will look into limiting factors of a highly deviated well located in the Gulf of Mexico. The Willcox reservoir, operated by Statoil, is used as a basic template for simulations run in the WELLPLAN^{TM} software. In WELLPLAN^{TM} we will extend the well trajectory in horizontal and vertical direction and observe the effect it has on factors like torque, drag and equivalent circulating density. The torque and drag results obtained from WELLPLAN^{TM} will be compared to some basic hand calculations. A sensitivity study will be conducted on different drilling parameters individually to see how it will affect different parameters at target depth. How big of an impact will a change in mud density and friction factor have on torque and drag? By pushing everything to its limits we will reach a theoretical maximum length extension for the well, both horizontally and vertically. The system requirements for this theoretical maximum will be compared to the specifications of two different rigs suited for operations in the Gulf of Mexico, to see whether or not the simulations could have a realistic outcome.

Deepwater drilling

General

The idea of drilling offshore came already in the 1870s, and since then the offshore drilling process has gradually evolved from shallow waters and lakes to depths up towards 3000m and beyond (Aadnoy, Cooper, Miska, Mitchell, & Payne, 2009). In 1947 the world's first "out of sight of land" well was built in the Gulf of Mexico, and a few years later, in 1953, the first floating drilling vessel was made from a navy cargo craft, and we might say that this was the oil industry's first steps towards deepwater development.

Drilling and development systems

A water depth greater than 1000 meters is considered deepwater, while greater than 1500m is ultra deepwater (Rajnauth, 2012), and drilling operations at these depths require specialized rigs. In water depths greater than 100m a semisubmersible rig is most commonly used (Aadnoy, Cooper, Miska, Mitchell, & Payne, 2009). These rigs are equipped with ballast tanks filled with air that makes it relatively easy to move them to target location. After being positioned the tanks are filled with water, submerging the lower part of the structure. Then the rig is being kept in position either by anchors or a dynamic positioning system, which by the help of thrusters and a navigation system keeps the vessel stable. Currently there are semisubmersible rigs capable of drilling in water depths up to 2400m. Drillships could be considered the ultimate deepwater drilling vessel, as operations greater than 3000m is already feasible using them. They use a positioning system with multiple anchors or thrusters, or a combination of both, and it is impossible to predict how deep operations might go considering the fast development during the last few years.

The real challenge in deepwater environments is the production of oil fields. Even though oil fields located at depths greater than 2000m are being produced, it is by no means standard procedure in the industry. Developments at this depth are extremely expensive and feasible only for large reservoirs with highly productive wells (Aadnoy, Cooper, Miska, Mitchell, & Payne, 2009). Figure 1 presents an overview of the most common production systems currently in use for deep water, and they are shortly described below:

- Fixed Platform: The jacket rests on the seafloor and a deck placed on top provides space for necessary equipment and constructions, capable of water depths up to 500m.
- Compliant Tower: A narrow flexible tower that flex with the wind, wave and current, making it suitable for deeper waters. The deck on top has room for drilling and production equipment and it is capable of water depths up to 800m.
- Tension-leg Platform: A floating platform kept in place by tension tendons, top and bottom segments used to attach it to the structure and seafloor, respectively. Capable of depths up to 1400m.

- Sea Star (Mini-TLP): The equivalent to the TLP. Has a relatively low cost, allowing it to be used in development of smaller deepwater reservoirs. Capable of water depths up to 1400m.
- SPAR: This tall vertical cylinder is kept in place by mooring lines or tethers. The cylinder is constructed with spiral flanges to reduce vortex shedding in strong currents, currently (2009) used in depths greater than 1600m, it is thought that existing technology can extend them to use in water depths beyond 2000m.
- Subsea system: Used to produce single or multiple wells. Production goes through a manifold and pipeline system to a distant production facility. Capable of water depths greater than 1500m.
- FPS (not on the figure): Consists of a semisubmersible unit equipped with drilling and production equipment kept in place by mooring or a dynamic positioning system. Used to produce subsea wells that will have their oil transported to the surface through production risers. Capable of water depths ranging from 200m to greater than 2000m.
- FPSO: A large tanker is moored to the seafloor, collecting production from nearby wells and periodically offloads it to a carrier tanker. It can be used as a temporary production system while another platform is built and for marginally economic fields as cost of pipeline infrastructure is avoided. Capable of water depths greater than 2000m.

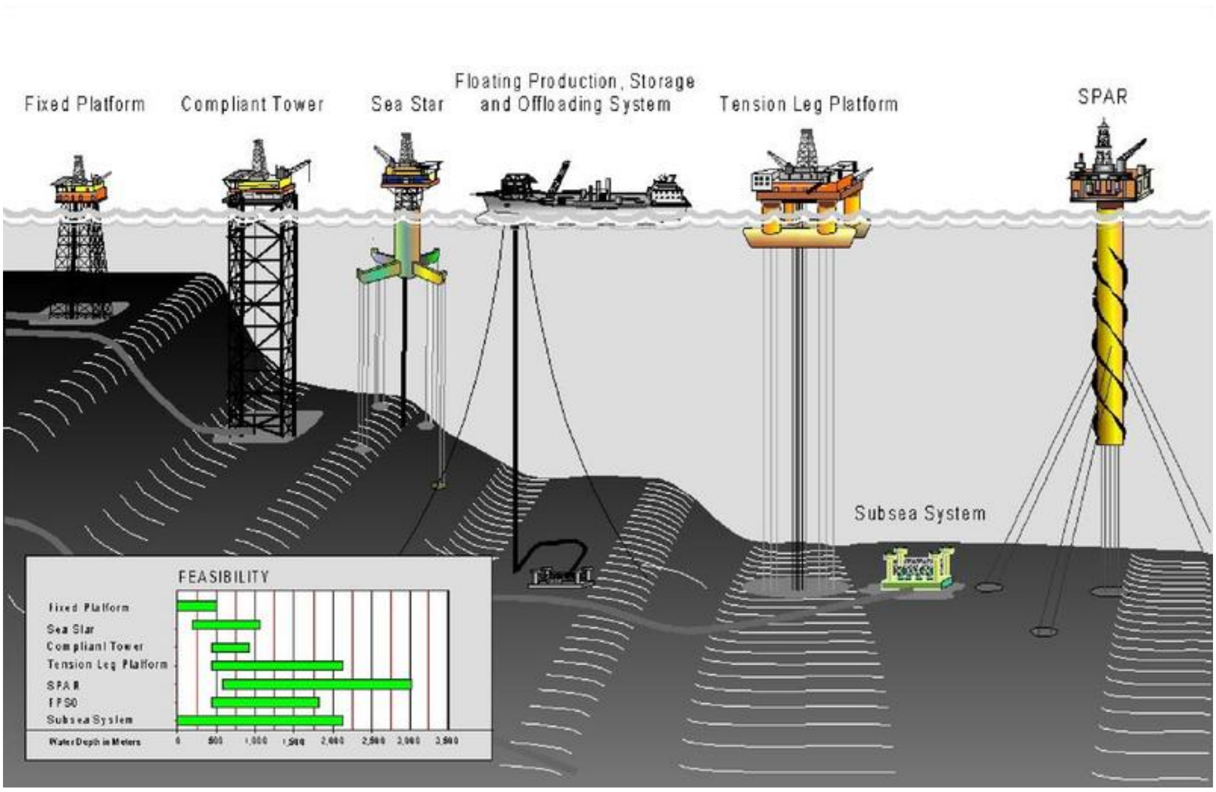

Figure 1: Deepwater drilling systems (Wikipedia, 2010).

Drilling fluids

Deepwater and ultra deepwater drilling projects are of immense complexity and require renewed technological support aiming at minimizing borehole problems and increasing well productivity. Chemical and physical properties of the drilling fluid may determine the success of such a drilling operation, and the fluids design requires extra attention (Aadnoy, Cooper, Miska, Mitchell, & Payne, 2009). Some of the factors involved in deepwater operations include low seabed temperatures, low fracture pressures and a narrow operational margin between pore pressure and fracture gradient, all of which a well design fluid could help manage. Liquid drilling fluids are generally classified as either aqueous or nonaqueous, where reservoir conditions determine which one is best suited. Aqueous fluids are water-based, while nonaqueous drilling fluids are water-in-oil emulsions.

The narrow operational window between pore pressure and fracture gradient is a problem often associated with deepwater drilling and may lead to loss of circulation and well control events. Lightweight fluids have been introduced as a possible solution, which may enable successful drilling of ultra deepwater wells. These fluids are capable of avoiding circulation losses and reduce formation damage, and developers are working on two different methods to use this:

1) Dual-gradient drilling with lightweight fluids
2) Formulation of noninvasive drilling fluids

With DGD the system has one effective fluid gradient between the surface and the seafloor, and another within the subsea well. As a consequence the effective mud weight at the previous casing is less than the effective mud weight at current drilling depth and we are able to manage the narrow pressure window. Fluid invading productive zones are detrimental to well productivity as it can cause irreversible formation damage and permeability reduction. Noninvasive fluids will help avoid excessive fluid penetration and promote pore plugging.

Cementing

Cementing jobs in deepwater wells provide many new challenges compared to onshore and shallow water jobs. Lower temperatures, different temperature gradients for the sea and the formation, formation and destabilization of gas hydrates and the narrow operational window between pore pressure and fracture gradient are some of them. (Aadnoy, Cooper, Miska, Mitchell, & Payne, 2009). Therefore it is important that cement-slurry design and cementing operations appropriately recognizes these problems. The bottomhole circulating temperature needs to be determined so the correct cement slurry can be designed regarding thickening time, compressive strength etc. Normally the API specifications are used for these design purposes, but the BHCT for deepwater wells are affected by many factors not taken into account by API correlations. Not having the correct thickening time may lead to excessive waiting-on-cement time, which leads to increased expenses as rig time for these operations are very costly.

At depths greater than 305m it can be a problem that water from shallow, overpressured formations can flow into the well compromising the hydraulic integrity of the tophole section. The water influx will cause poor cement isolation, which may lead to problems such as buckling or shear of the casing. To avoid or control shallow water flow it is recommended to make sure that rheological parameters are designed properly so they cause an efficient displacement of the previous fluids pumped into the well. Additionally; should the cement slurry have certain characteristics like fast liquid-to-solid transition, long term sealing and good control of fluids. As a way to ensure that hydrostatic pressure is transmitted to the formation, two slurries can be used with the lead slurry having longer thickening time than the tail slurry. Should gas hydrates be present it is important that the cement slurry exhibit low heat of hydration to avoid destabilization of gas hydrates.

Fracture-Pressure Gradient

The fracture-pressure gradient is defined as the pressure gradient that will cause fracture of the formation (Aadnoy, Cooper, Miska, Mitchell, & Payne, 2009). Meaning that if a pressure higher than the formations fracture-pressure is acting, the formation will break and lost circulation might occur. As mentioned before the pressure window between pore pressure and fracture-pressure gradients are much smaller for deepwater drilling. This is mainly because of the low stress regime as a result of the reduction of the overburden-pressure gradient. The fracture gradient might be reduced even further by structurally weak, undercompacted, and unconsolidated sediments commonly found in the shallower portion of the underground. In these conditions the mentioned operational window will be reduced more and more as the water depth increases. As a result it is not uncommon to have an excessive number of casing strings, small hole size at total depth, inability to reach total depth or fracturing of the formation during kick-control operations.

Two classifications are used when talking about methods used to estimate the fracture-pressure gradient, “direct” and “indirect”. Direct methods rely on measuring the pressure required to fracture the rock and the pressure required to propagate the resulting fracture. Indirect methods are based on analytical or numerical models and are able to estimate fracture pressure along the entire well, but required data is often difficult to obtain.

Deepwater Challenges

Long distance between the drilling vessel, the top of the well and working environment for well-control equipment provide many challenges (Aadnoy, Cooper, Miska, Mitchell, & Payne, 2009). Drilling riser and kill and choke lines represent high loads on the drilling vessel escalating capacity requirements drastically. A gas kick can be hard to detect because the gas barely expands between the reservoir and BOP, causing the gas to be in the riser before the BOP is closed. Long kill and choke lines cause large pressure losses when kicks are circulated out, complicating the use of conventional kick-control methods.

Field-development and production technology for shallow waters have been extended to the deepwater environment. This is a bit problematic as deepwater equipment is more complex and expensive than its equivalent shallow-water version. High loads, limited access and lack of long-term experience make it difficult to maintain an acceptable reliability for this equipment. Some deepwater-platform concepts such as tension leg platform use rigid risers with surface production trees to maintain access to the wells. But vertical riser loads and hydrodynamic forces make it so that these concepts can only be applied down to a certain depth.

Wellbore stability and pore pressure related issues cause problems during drilling, logging and production operations, and it will be important to overcome these when operating in deep waters. Especially the narrow pore pressure and fracture gradient window cause a lot of problems, and errors in predictions could potentially lead to significant loss of rig time and even failure of wells (Klimentos, 2005). High pressure buildup around the wellbore may lead to problems such as stuck pipe, borehole collapse, sloughing shale and excessive fill. Therefore it is important with wellbore stability analysis and pore pressure prediction considering how costly exploration and field development is in deep waters. Additionally these predictions are important in order to obtain the full benefit of directional drilling technology. Normally wellbore stability can easily be managed by critical mud weights that provide sufficient wellbore wall support to counteract the redistribution of stresses resulting from the creation of the wellbore. However, due to operational systems available there are limitations to available mud weights which could prove problematic.

"The in-situ state of stress is defined in terms of the order and magnitudes of the three principal stresses; one of which is generally vertical, the other two horizontal, and the direction of the horizontal stresses (Klimentos, 2005)." Because of the orientation of these stresses and mechanical instabilities drilling deviated wells will result in additional challenges. The two types of mechanical instability that can occur are: tensile fracturing, which is due to excessive pressure exerted by the wellbore fluid, and compressive shear failure due to insufficient wellbore fluid pressure. Mechanical factors play a dominant role in wellbore instability during drilling, and can be observed with even the most inhibitive drilling fluids (oil-based). Mechanically induced instability can create a severe environment for inclined wells if the direction and inclination of the wells is parallel with the stress field. This basically means that the chances of causing severe well damage is doubled when drilling horizontally and could be a reason why there are more vertical wells in deep water than inclined ones, as they are easier to operate. In order to deliver successful deepwater wells in the future it is critical to have very effective well planning.

One of common problem regarding deepwater drilling is whether or not target reservoir is economically feasible. This is largely due to the high costs associated with equipment that can handle the deep water challenges. Bigger and more equipment means that fourth- and fifth-generation rigs must be used, and they are generally more expensive than previous generations in addition to being fewer in numbers. A solution to this is introduced with slender well technology, which basically is to reduce the diameter of the drilling-riser from 21 inches to 15 inches (Aadnoy, Cooper, Miska, Mitchell, & Payne, 2009). By eliminating a casing string and moving away from the conventional casing design it is possible to use older generations of rigs. Another advantage with this technology is the reduction in volume capacity for the drilling riser, which means that there will be less leakage should an accident occur. However, good knowledge about the pore-pressure and fracture gradient is required as the 17 ½ inch phase has to go deeper in a riserless mode. As a result this technology is not well suited for exploratory wells. It seems that wells of this sort will be more susceptible formation damage, especially if the wells are highly deviated, and will be a greater threat to the environment. In these post-Macondo days it would be wise to take extra care if a project chooses to go with slender well technology. The disadvantages taken into account, slender wells still seem to a very attractive solution to drilling in deep waters. If this method works as intended many smaller reservoirs located in deep and ultradeep water can become economically feasible. The method might also work well in conjunction with DGD technology considering the superior pressure control it provides.

Gathering sufficient wellbore data will be of high importance because of the narrow pore pressure and fracture gradient window, as mentioned earlier. The industry drilling envelope (Figure 2) is a great tool for this, as it shows wells that have been drilled by different companies' anno 2009 (Hutchison & Robertson).This way we will be better prepared for new operations if we are able to obtain wellbore information from similar reservoirs from other companies. It will improve the accuracy of simulations as well, as we gain better values for friction factors, thermal gradients etc. Figure 2 also includes location for the reservoir used in this simulation, as green and blue squares. The green square is normalized for water depth, while the blue is not.

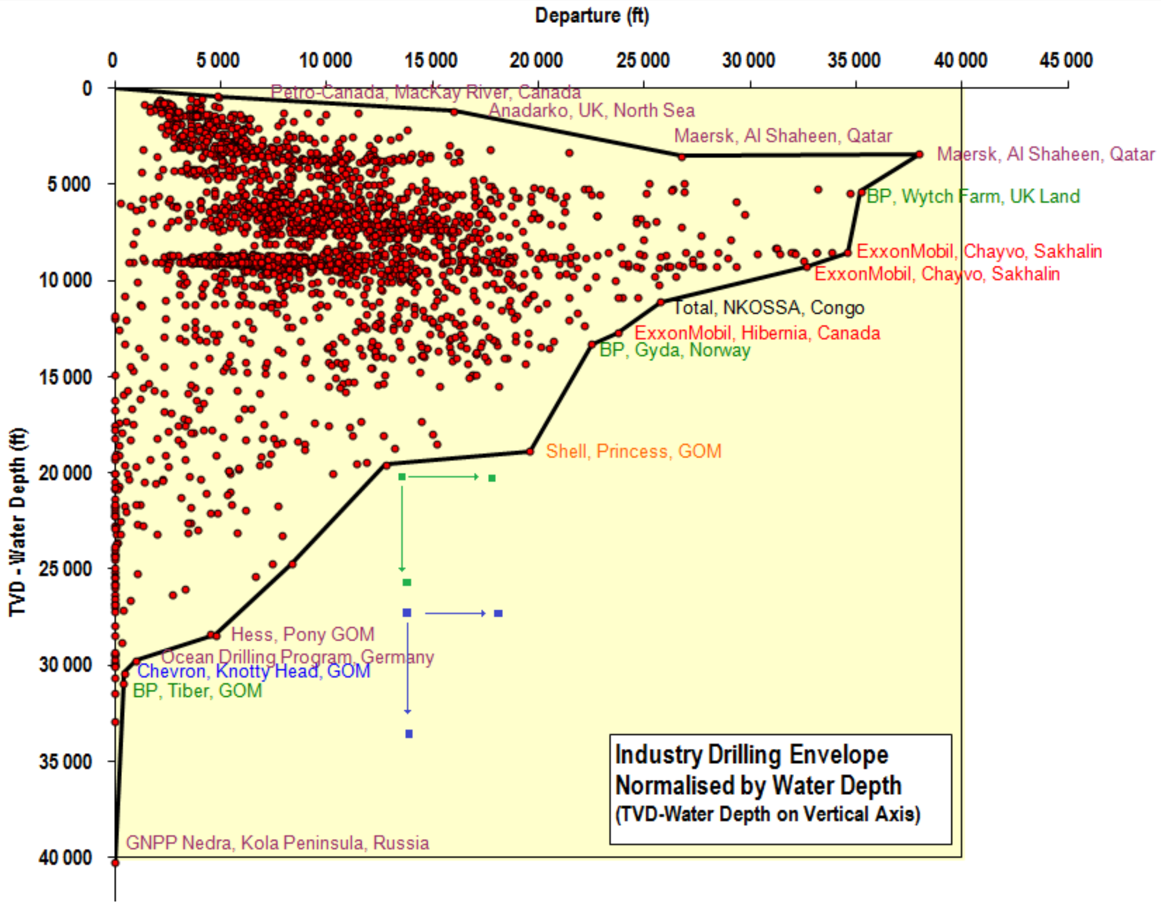

Figure 2: Industry Drilling Envelope showing target reservoir with horizontal and vertical extension (blue squares) and normalized by water depth (green squares) (Hutchison & Robertson).

Drilling in deep water is hard enough by itself, and it becomes significantly more difficult when we add inclination to the wells. High torque, drag and ECD values are some of the problems that escalate as we start drilling horizontally. The overburden pressure increases the chances of wellbore collapse, and due to the narrow pressure window and mud weight limitations some deviated wells are risky business. However, different technologies addressing these problems are being developed at a remarkable speed, increasing accessibility to reserves, improving wellbore integrity and providing a safer work environment (Aadnoy, Cooper, Miska, Mitchell, & Payne, 2009). Some of the technologies that are currently under development and/or being used to handle some of the problems listed earlier are briefly described in the next subchapters.

Underbalanced Drilling

Concept

"Underbalanced drilling is a mode of rotary drilling that is carried out with a bottom hole wellbore pressure less than formation fluid pressure (Sangesland, Xiaojun He, & Islam, 2011)." Compared to the conventional "overbalanced" drilling, where the wellbore pressure is kept higher than the formation pressure in order to prevent formation fluid influx, what is also known as a kick. In deepwater drilling it will be more difficult to keep the wellbore pressure above formation pressure, making a kick more likely to occur, which is why underbalanced drilling will be better suited for the job. By keeping the pressure at the sand face of the wellbore lower than the formation pressure we allow formation fluids to flow continuously into the wellbore. The larger this pressure difference is, the greater the inflow rate. Rate of inflow and evacuation of formation fluids at the top of the well is controlled by applying backpressure at the surface. Pressure control is obtained by a rotating control head with a rotating inner seal assembly is used in conjunction with the rotating table (Rigzone). To be able to successfully perform an UBO both drilling and completion operations must remain constant at all times during the operation.

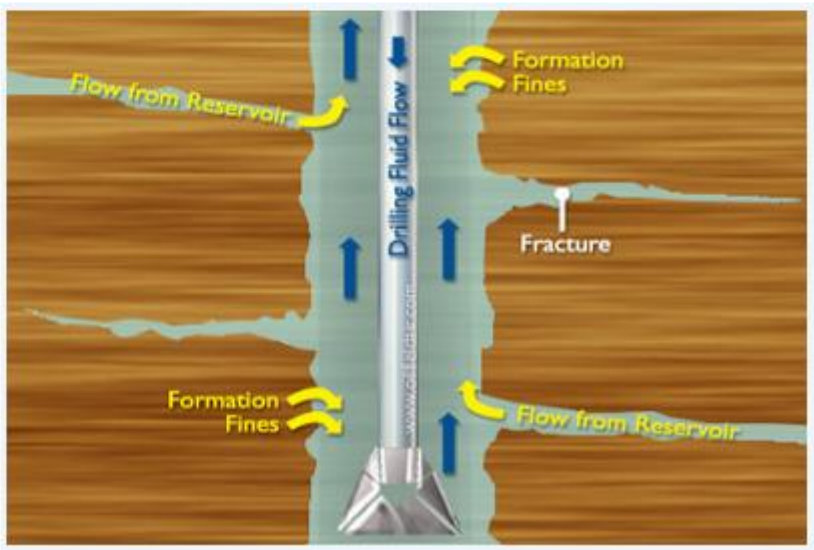

Figure 3: Underbalanced Drilling (Rigzone).

Underbalanced Techniques

Several types of fluids are used in underbalanced drilling operations depending on a wide range of considerations (Sangesland, Xiaojun He, & Islam, 2011) including reservoir pressure and depth, properties of the formation fluid and physical and chemical properties of the formation rock among others. Which fluid type is used can be categorized as different types of underbalanced drilling operations, these are (Sangesland, Xiaojun He, & Islam, 2011):

Liquid Mud
When the formation pressure is high and a liquid with no added gas is light enough to provide required underbalanced conditions this fluid type is used. It is similar to the mud used in conventional drilling and can be either water based or oil based containing a variety of additives to give desired properties. The mud used is a homogenous liquid and compressible with constant density, however, it might become compressible if mixed with formation hydrocarbon in the annulus of the wellbore.

Gasified Liquid
Most commonly used to drill with low hydrostatic pressure. In this method gas is mixed and entrained in liquid mud, which can be water or oil based, making it lighter. The mud and gas are immiscible, meaning that they do not dissolve in each other, they are non reactive and do not have a tendency to form stable foams or emulsions. Different types of gas can be used depending on the operation including nitrogen, natural gas, air and exhaust gas. Flow behavior of gasified mud is somewhat complicated and calculating pressure conditions in the well is rather involved.

Stable Foam
The foam is a mixture of two immiscible fluids that form a homogeneous emulsion in the presence of small quantities of foaming agents. Containing from 55% to 97% gas, the foam usually consists mainly of nitrogen as it is inert and environmentally friendly. Regular process is to mix the foam at the surface by injecting liquid into the compressed gas stream at the stand pipe. Foam returning to the surface is directed to a separator where it is broken into gas and liquid, which is either treated and disposed or recovered and recycled. The emulsion structure of the foam gives it excellent solid carrying capacity, enabling it to carry cutting at a relatively low annulus flow velocities. Foam is a costly method and due to temperature limits it is seldom used deeper than 3,658m (Rigzone).

Gas
Dry gas is used as the drilling medium, with no intentional adding of liquids. This is the most common used UBD method, and is used in other instances than the petroleum industry like civil engineering applications among others. Different types of gas are used depending on the situation, for instance air is widely used, but it is only suitable where the hole is dry and is thus irrelevant for deep water operations. Other types of gas include nitrogen, natural gas and exhaust gas. At locations where a natural gas compressor is already in existence gas drilling is a very attractive method as the gas can be used for gas injection, gas lift or gas transport operations.

Mist
Drilling with mist is pretty similar to gas drilling, only difference being that very small quantities of liquid, typically less than 2.5%, are injected into the gas stream. This liquid mist is introduced to assist in lifting small powder-like cutting surrounding the bit and to clean the face of the drill bit.

Comments

Underbalanced drilling has many advantages and is rapidly evolving into a main stream procedure for both onshore and offshore fields. Formation damage can be completely avoided as no invasion will occur if the underbalanced state is maintained until the well starts producing. When drilling conventionally lost circulation will occur until a proper mud cake is formed, during UBD no mud will enter the formation and lost circulation can be prevented. The pressure at the bottom of the wellbore is less than with conventional drilling, increasing ROP as it is easier to cut and remove rock (Sangesland, Xiaojun He, & Islam, 2011). UBD also has its disadvantages; it is more expensive than conventional drilling and some of the methods are not well suited for deep water operations like air drilling and foam as mentioned earlier. Both MPD and DGD seem to have greater potential when it comes to deep water and ultra deep water operations as UBD has no direct mean of handling pressure at the seafloor and the sea pressure gradient.

Managed Pressure Drilling

Concept

"Managed Pressure Drilling is a method of drilling in a balanced or overbalanced state while threading the pressure limit between pore pressure or wellbore stability and fracture pressure" (Cohen, Stave, Schubert, & Elieff, 2008). MPDs main goal is to avoid well kicks. The discipline was developed as a result of the high cost of nonproductive time caused by the close proximity between pore pressure and fracture pressure. A problem often associated with marine drilling in soft sediments, but it can be the solution to deep water drilling as it allows the drilling to continue uninterrupted for longer periods. MPD is a general description for well-bore-pressure management, solving problems including:

- Extending casing points, limiting the total number of casing strings and the subsequent hole size reduction.
- Limiting NPT associated with hole size reduction.
- Avoiding the lost circulation-well kick sequence.
- Limiting lost circulation.
- Drilling with total lost returns.
- Increasing penetration rate.
- Deepwater drilling with lost circulation and water flows.
- Reducing ECD when drilling extended reach wells and wells with narrow margins between formation breakdown and well kicks.

IADC defines MPD as "an adaptive drilling process used to more precisely control the annular pressure profile throughout the well bore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. This may include the control of back pressure by using a closed and pressurized mud return system, downhole annular pump or other such mechanical devices. Managed Pressure Drilling generally will avoid flow into the well bore." (Cohen, Stave, Schubert, & Elieff, 2008) The definition does not mention that MPD uses a single-phased drilling fluid treated to produce minimal flowing friction losses in most cases. The process employs a collection of tools and techniques to mitigate the risks and costs associated with drilling wells that have narrow downhole environmental limits, and although there are some equipment similarities to underbalanced drilling operations, MPD is in no way the "poor boy" version of underbalanced drilling (Malloy, 2007). It requires both engineering forethought and planning, even though the equipment footprint is not as extensive. MPD comes in different variations, and one method does not address all problems encountered. We will have a choice between different techniques covered under MPD.

Basic Techniques

Constant bottom-hole pressure (CBHP)

This term generally refers to actions taken to correct or reduce the effect of ECD or circulating friction loss. More specifically it is applicable to avoid changes in ECD by applying appropriate levels of surface backpressure, this causes the bottom hole pressure to remain constant during the complete drilling operation (Cook, et al., 2008). CBHP can also be used to control the situation when an underbalanced condition is obtained while drilling through an unexpected zone that has a pore pressure greater than the maximum equivalent pressure reachable by the proposed mud system. During the drilling operation we can avoid influx by increasing the annular friction pressure from pumping. A non-retrievable valve is placed inside the drillstring at the least; this is to prevent mud from flowing up the drillpipe to the surface (Malloy, 2007).

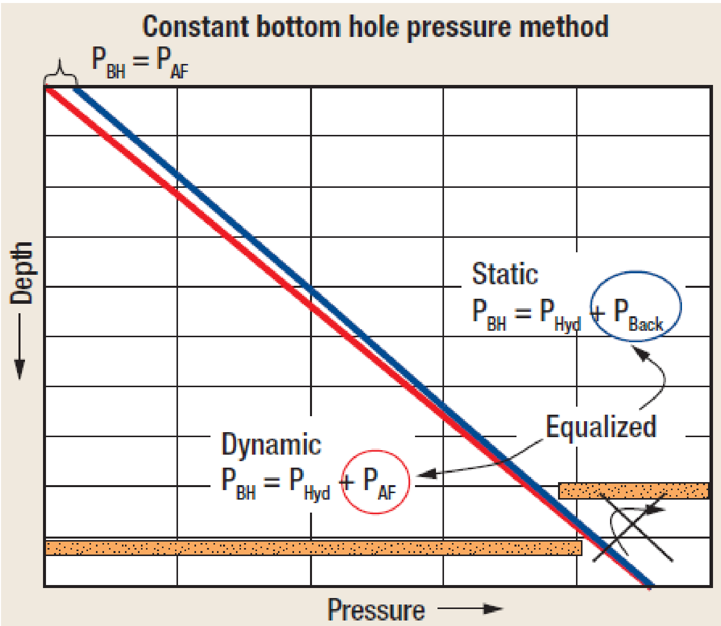

Figure 4: CBHP uses lower-density drilling fluid and imposes backpressure when static to equalize annular friction pressure (Malloy, 2007).

Pressurized mud-cap drilling (PMCD)

With this technique there are no returns going to the surface and we have a full annular fluid column maintained above a formation that is taking injected fluid and drilled cuttings when drilling. This annular fluid column requires an impressed and observable surface pressure to balance the downhole pressure. It is a technique developed to drill with total lost returns (Cohen, Stave, Schubert, & Elieff, 2008). The way it works is that a heavy, viscous mud is pumped down the backside in the annular space to a certain height. This will work as the "mud cap", serving as an annular barrier while we can use a lighter, cheaper and less damaging fluid to drill into the weak zone (Figure 5). The lightweight fluid is pumped down the drillpipe and circulated around the bit. After the circulation the fluid and cuttings are injected uphole below the last casing shoe into a weak zone, with the heavy mud remaining in the annulus acting as a mud cap above the weak zone. Should any problems occur with the annular pressure, then it is possible to apply optional backpressure in order to maintain control. The lighter fluid used will improve the ROP because of an increase in hydraulic horsepower and reduction in chip hold-down (Malloy, 2007).

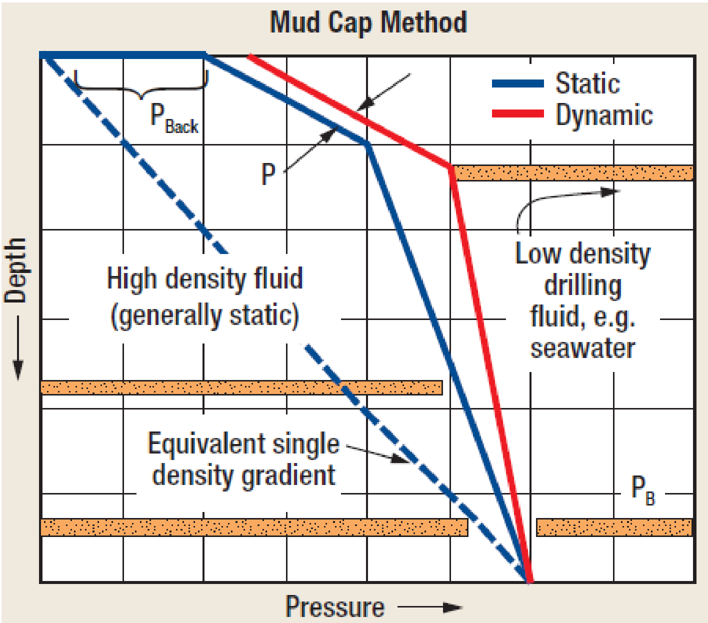

Figure 5: PMCD uses a lightweight scavenger drilling fluid, with a heavy mud in the annulus to maintain annular pressure control (Malloy, 2007).

Casing while drilling

In this method we use the casing as the drillstring so that the well is drilled and cased simultaneously (Malloy, 2007). Due to the narrow clearance between formation wall and OD, annular friction will be a significant variable in ECD control. Flow within the small annular space will contribute to an increased annular pressure from the shoe to surface (Figure 6). There is potentially a huge economical benefactor by using this method as drilling time could be cut in half and money would be saved on the liner.

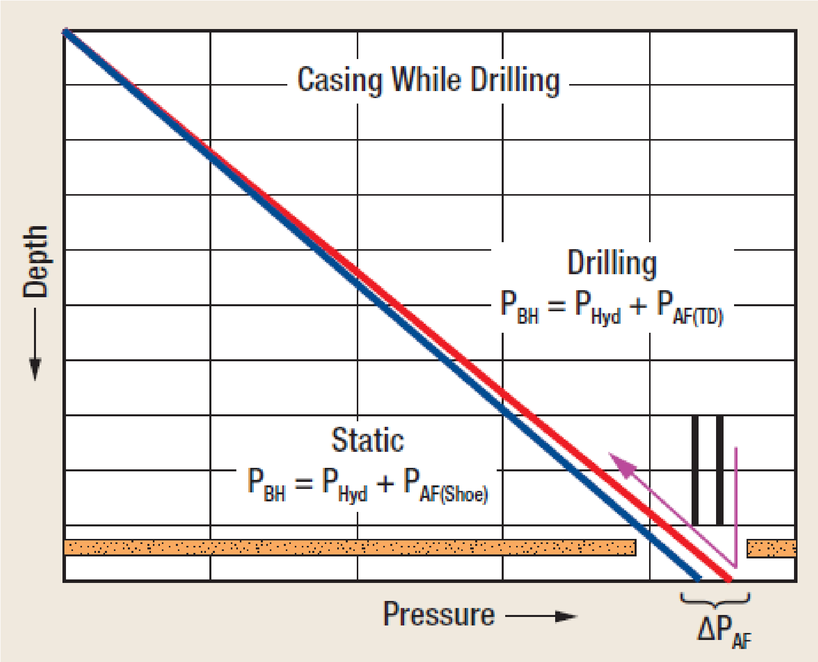

Figure 6: For casing while drilling; pumping manages friction pressure through the casing drillstring (Malloy, 2007).

Dual gradient

This might be the MPD technique with the greatest potential, and it has been developed into its own technology over the last few years with its own variations. A more thorough explanation of the method is found in the next subchapter.

Dual Gradient Drilling

Concept

Dual Gradient Drilling technology is a variant of Managed Pressure Drilling, an advanced form of primary well control that allows potentially greater and more precise control of the annular wellbore pressure profile than mud weight and pump rate adjustments alone. IADC defines Dual Gradient as: "Creation of multiple pressure gradients within select sections of the annulus to manage the annular pressure profile. Methods include use of pumps, fluids of varying densities, or combination of these ((IADC), 2008)."

In these offshore drilling operations mud returns do not travel through a conventional, large-diameter drilling riser. Instead the returns are dumped at the seafloor, so called "pump and dump", or returned back to the rig through one or more small-diameter return lines, known as "riserless mud return" (Cohen, Stave, Schubert, & Elieff, 2008). When returning the mud to the surface a seafloor or mud-lift pump is installed, taking the returns from the seafloor well annulus and pumping it back to the surface. The inlet pressure of the seafloor pump can be adjusted to near seawater hydrostatic pressure, this way a dual-pressure gradient is imposed on the well-bore annulus, similar to the way riserless drilling imposes the seawater hydrostatic pressure in the annulus of the well. From Figure 7 it can be seen that a seafloor pump will reduce the pressure imposed on the shallow portion of the well, and higher-density mud below the seafloor will achieve required bottom-hole pressure required to control the formation pore pressure.

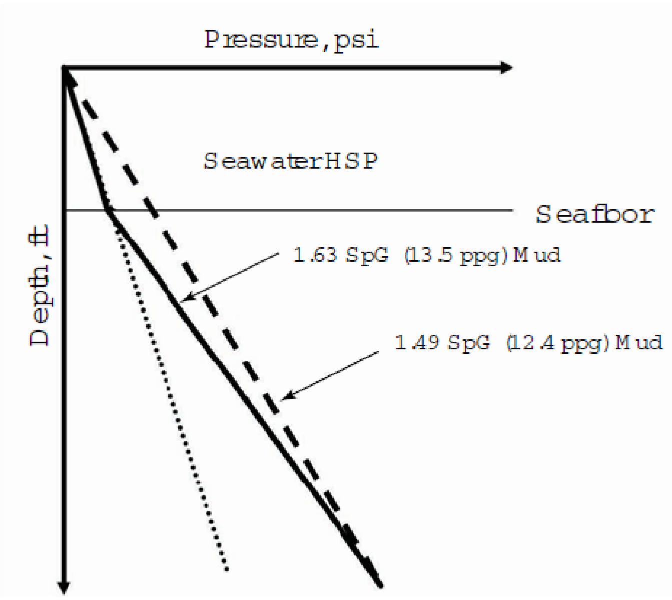

Figure 7: Single gradient vs dual gradient concept (Cohen, Stave, Schubert, & Elieff, 2008).

Implementation challenges

Even though dual gradient technology can be the solution to controlling ECD and other problems, there are a few challenges involved when using the method. The main challenges of general and DGD MPD can be divided into two categories; Operational and Technical requirements. Well control is particularly challenging and unique to the different DGD methods; from kick detection through re-establishing primary barrier control (hydrostatic) (Kozicz, Juran, & de Boer, 2006). Barriers are divided into primary and secondary, and are important to keep up during drilling operations, especially deep water operations as failures here can be of bigger impact (just look at the recent accident in the Gulf of Mexico). Primary barriers are the elements that are directly exposed to the formation pressure and include fluid column and production casing among others (Wellbore). Secondary barriers provide back-up to the primary barriers and consist of intermediate casing, wellhead etc. Another prioritized consideration is determining design and equipment requirements needed to implement the MPD (or DGD) techniques, and looking into limitations and adaptability of existing drilling equipment. For dual gradient systems the challenges are related to whether a subsea pumping or dilution system is used. For subsea pumping the primary issues are related to size, weight and power requirements of the subsea pumping assembly and its ability to pump solids of varying sizes. Fluid dilution systems usually employ aerated or lightweight fluid in order to achieve required riser fluid density. The main considerations involve fluid separation capacity, circulation rate and in the case of aerated fluids; the ability to handle explosive gases. There are also challenges considering process controlling, external differential pressure and surface applied pressure that I won't go more in depth on in this thesis.

Dual gradient methods

Companies are currently developing different versions of the DGD technology, using either dilution or subsea pumps as a method to manipulate two or more fluids within the wellbore and achieve desired annular pressure profile. Most methods are not yet commercially used, but are planned to be up and running within a couple of years. Hopefully this will help developing fields in even deeper water than what is currently under operation. Five DGD methods are introduced below:

Subsea Mudlift Drilling - SMD

In late 2006 Chevron's Deepwater Drilling organization decided to improve safety, predictability and economics of its operations in deep water. Several different options were evaluated and in the end using a single riser with the MLP run in-line with the riser was determined to be the most feasible solution, with optimal safety and lowest long-term cost (Dowell J. D., SPE 137319, 2010). The basic principle is the same, with mud in the drilling riser replaced with a seawater-density fluid. As a result one can use a denser mud below the mudline. It is designed to operate in water depths from 1200-3050m (Østvik, 2011).SMD requires adding significantly new hardware to the rig other than what is common for DGD; this includes Subsea Rotating Device (SRD), MudLift Pump (MLP), Solid Processing Unit (SPU) and Drill String Valve (DSV). Mentioned equipment is placed subsea, but some changes also need to be done at the surface. Six pumps must be installed, three for power fluid and three for mud, one should also be kept as backup. Additional piping is required as up to three fluids at once need handling. Two trip tanks are installed, one for the riser fluid and one for mud in the hole below, both of them being circulating trip tanks. The return line manifold provides a way to divert mud to the pits, MGS, rig choke and drilling choke. The drilling choke prevents the return line gas to expand uncontrollably. The tripping and displacement manifold allows for management of fluids in riser, choke and kill line. Additionally the drilling riser need some modifications as the MudLift pump is seawater-powered. Figure 8 shows the system layout for SMD.

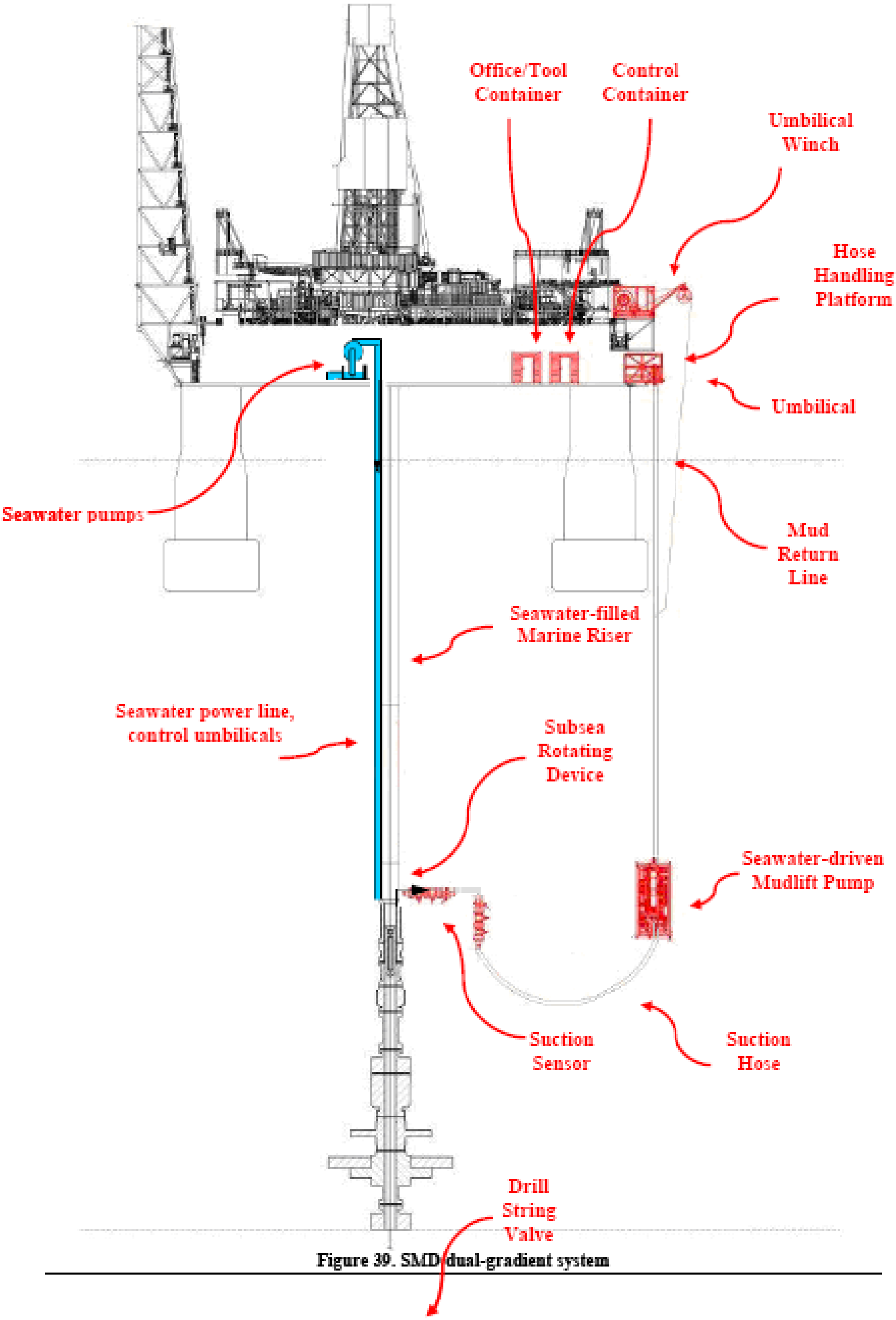

Figure 8: SMD system layout(Østvik, 2011)

Continious Annular Pressure Management – CAPM

Industry experts claim that problems related to wellbore pressure can result in downtime with an estimated value up to 15 percent of exploration and development drilling cost (Begagic, Addressing Deepwater Challenges with CAPM™). CAPM was developed by Transocean as a mean of reducing these costs by reducing operational risks and making "undrillable" wells drillable. Its intended for use in deepwater areas, but it can also be applied for shallow water with High Pressure/High Temperature (HPHT) applications. HPHT areas often suffer from lost circulation during drilling, which require additional casing strings. This means reduced wellbore diameter and desired locations can no longer be reached without the use of CAPM. CAPM combines a dilution-based, dual-gradient drilling process with a closed circulation system, and enables operators to bend the mud curve. A light drilling fluid is pumped down the annulus between the drilling riser and an inner riser; the pumping process can also be accomplished by using dedicated booster lines (Begagic, Deepwater Dual Gradient Drilling Overview, 2011). This fluid mixes with the return from the wellbore and creates a lighter density mud in the drilling riser. The mud is processed through centrifuges to separate into the light dilution fluid and the heavier drilling fluid. As a result we get drilling operations with enhanced kick detection, improved safety margins and potentially simplified well design. Figure 9 shows the system layout for CAPM.

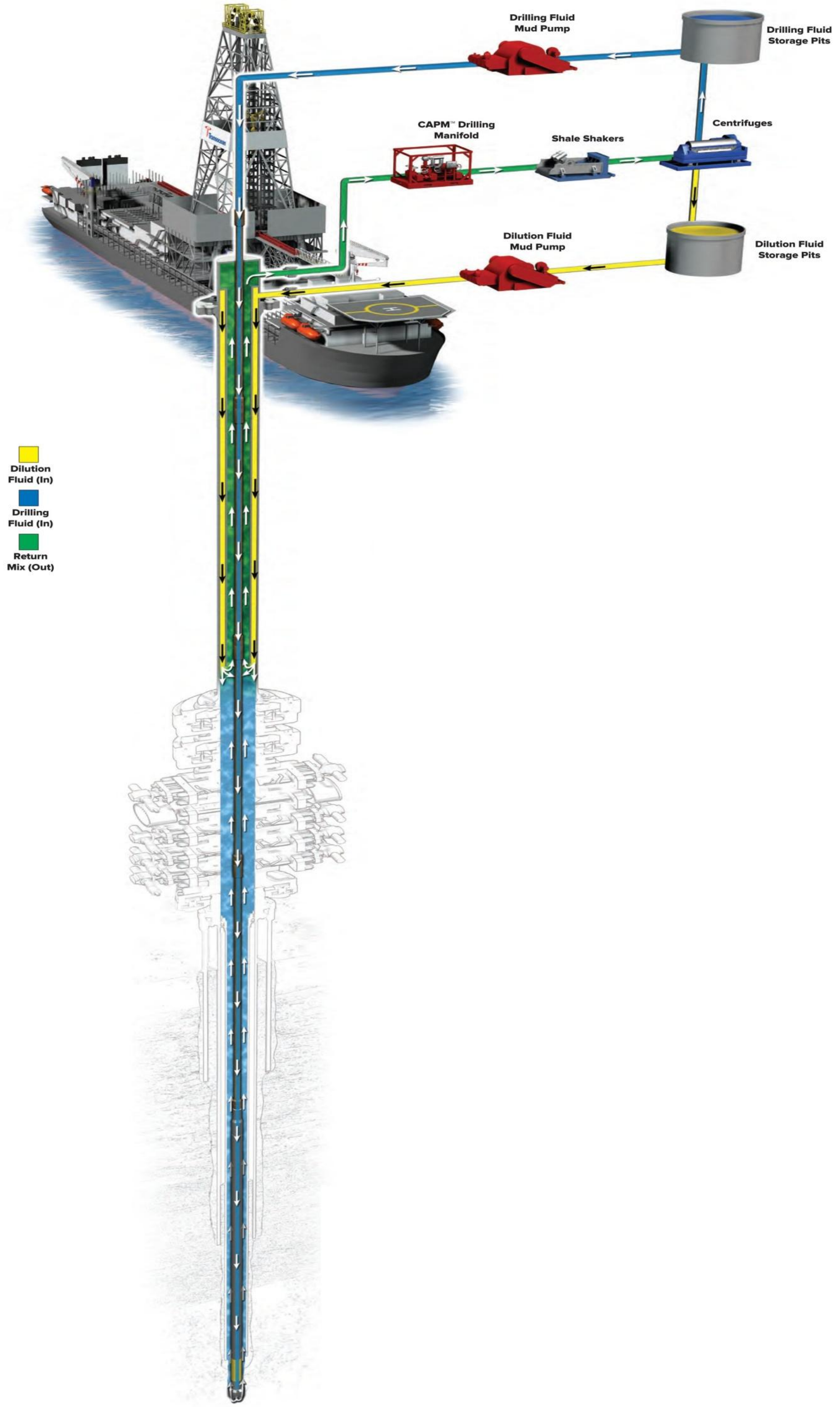

Figure 9: CAPM system layout (Begagic & Kozicz, Potential CAPM Opportunities, 2010)

Low Riser Return System – LRRS

LRRS is patented by Ocean Riser Systems. It is used as a method of managing pressure during drilling by adjusting the mud level in the marine riser and returning mud and cuttings to surface using a subsea pump and a separate conduit (Falk, Fossli, Lagerberg, Handal, & Sangesland, 2011). As a result of manageable height of mud in the riser, annular and bottom hole pressure can be changed and proactively managed. LRRS can be used for different purposes, for instance purely for ECD compensation or in combination with a heavier than conventional mud weight and lower static level in the riser. By using conventional mud weight conventional well control procedures can be used. Circulation up the annulus will increase bottom hole pressure and ECD components build up, the subsea pump will be used to lower the mud level and the control system will continuously adjust the mud level in the riser (which is full to the flowline outlet during static conditions) to compensate for increased BHP due to the ECD effect. Hence we can keep BHP or any fixed point in the wellbore within pore and fracture gradient window by controlling rig pumps and subsea lift pump rates. This is used to drill longer hole sections in wells with narrow operational mud windows, for instance depleted formations, and to avoid losses during drilling, cementing and completion. Figure 10 show the layout system for LRRS.

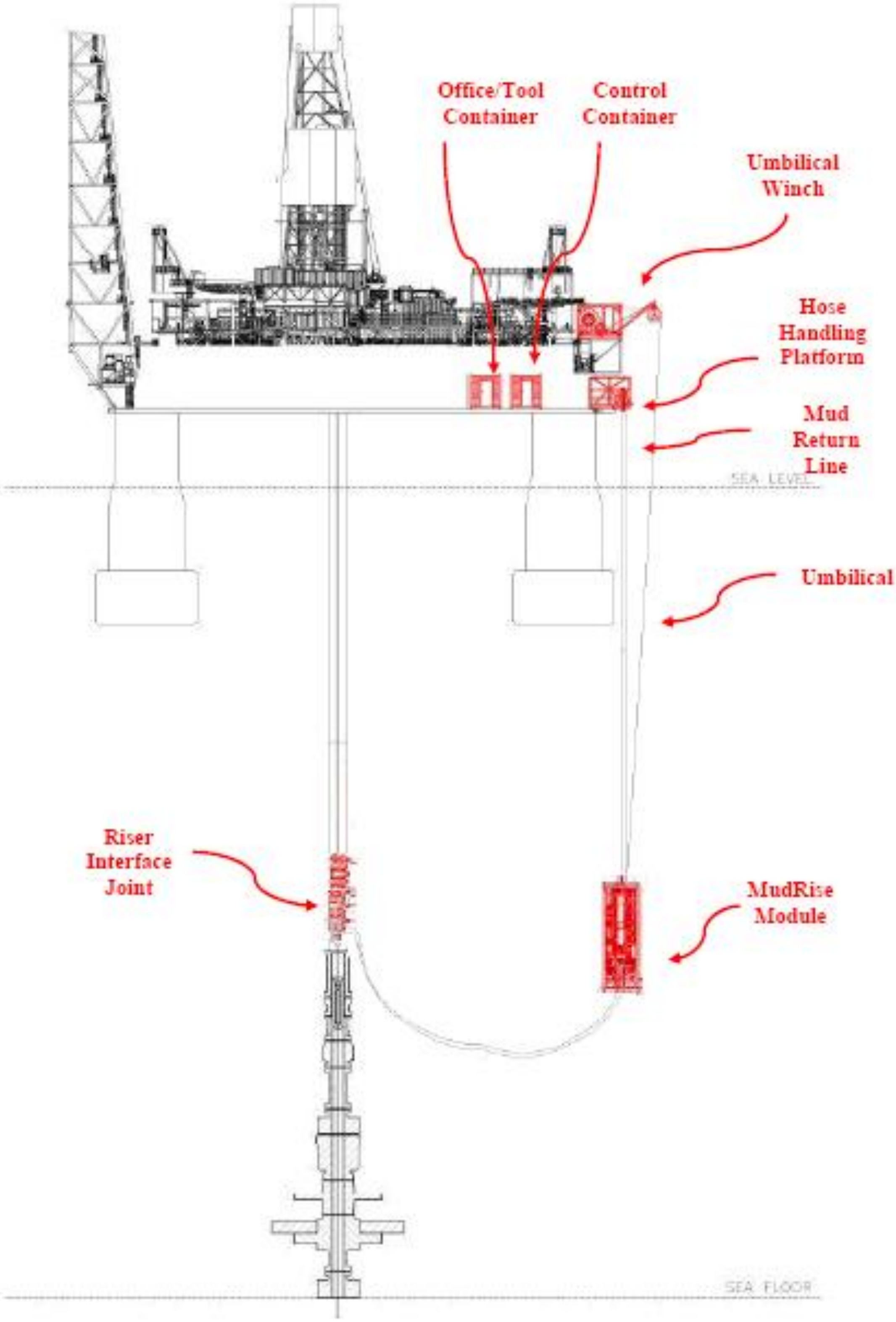

Figure 10: LRRS system layout (Østvik, 2011)

Riserless Mud Recovery – RMR

RMR is a tophole drilling tool and a closed circulation mud system without marine drilling riser. It is the only commercial DGD technology currently in use, by BP in Russia and Shell in Australia (Oljedirektoratet) among others. The method was developed to recycle and return drilling fluid and cuttings from the subsea wellhead to the surface, its main purpose being to keep costly mud in circulation. This meant that fluids previously considered too expensive could be used. It eliminates the use of "Pump and Dump", which means zero discharge and less environmental impact and pollution (AGR). Since the tophole section is drilled with a "closed loop" fluid volume can easily be monitored and any change to the total volume is quickly discovered, hence improved kick detection. Heavier mud prevents shallow gas influx which may occur during conventional drilling (Østvik, 2011). Additionally it allows for deeper surface casing and better hole stability. The method was developed for up to 400m depth, AGR and Statoil are working on using it up to 450m. RMR consists of a Suction Control Module (SMO) installed on top of the subsea wellhead that collects mud and cutting returns from the well, which is pumped to the surface via a Subsea Pump Module (SPM). Operators control the pump in order to keep the mud level full during the different operations. During the start up phase the interface between drilling fluid and seawater is observed, and the pressure measured by the SMO is set as the point for suction control. A computer system is used to control the pump speed and any changes in the interface changes the pump speed, which makes it easy for RMR to compensate for most changes during the drilling operation.

Controlled Mud Pressure – CMP

CMP is an extension of AGR's Riserless Mud Recovery (RMR) method (SINTEF, 2008); with the main difference being that CMP uses a fluid filled marine drilling riser. This allows for control of the bottom hole pressure and equivalent circulating density (Østvik, 2011). The riser docking arrangement itself is not fully finalized, but currently described with the docking above subsea wellhead and BOP. It also includes the diverter for the subsea mud pump and a docking for the riser to surface (Hansen, 2011). The module and connection to the pump module provides the connection of choke lines to the pump module. This is done to give the mud return line (MRL) and subsea mudpumps access to the well annulus during a shut-in and well control situation. The subsea pump module (SMP) sets the limit of the CMP operation and when it's connected to the riser it allows the pump to return fluid from the BOP area through the MRL that extend back to the surface. It is important that this line has a choke valve as a mean of controlling gas in the MRL in well control situations. At what sea depth the connection of the MRL happen, is determined by the lifting capacity of the pump at a desired flow rate. When the suction pressure set point is set the system starts. A computer adjusts the pump speed based on this point and mud weight is gradually increased to achieve desired BHP and keep suction pressure constant. During drilling the subsea pump circulate mud and cuttings back to the surface avoiding the riser. Figure 11 shows the layout system for CMP.

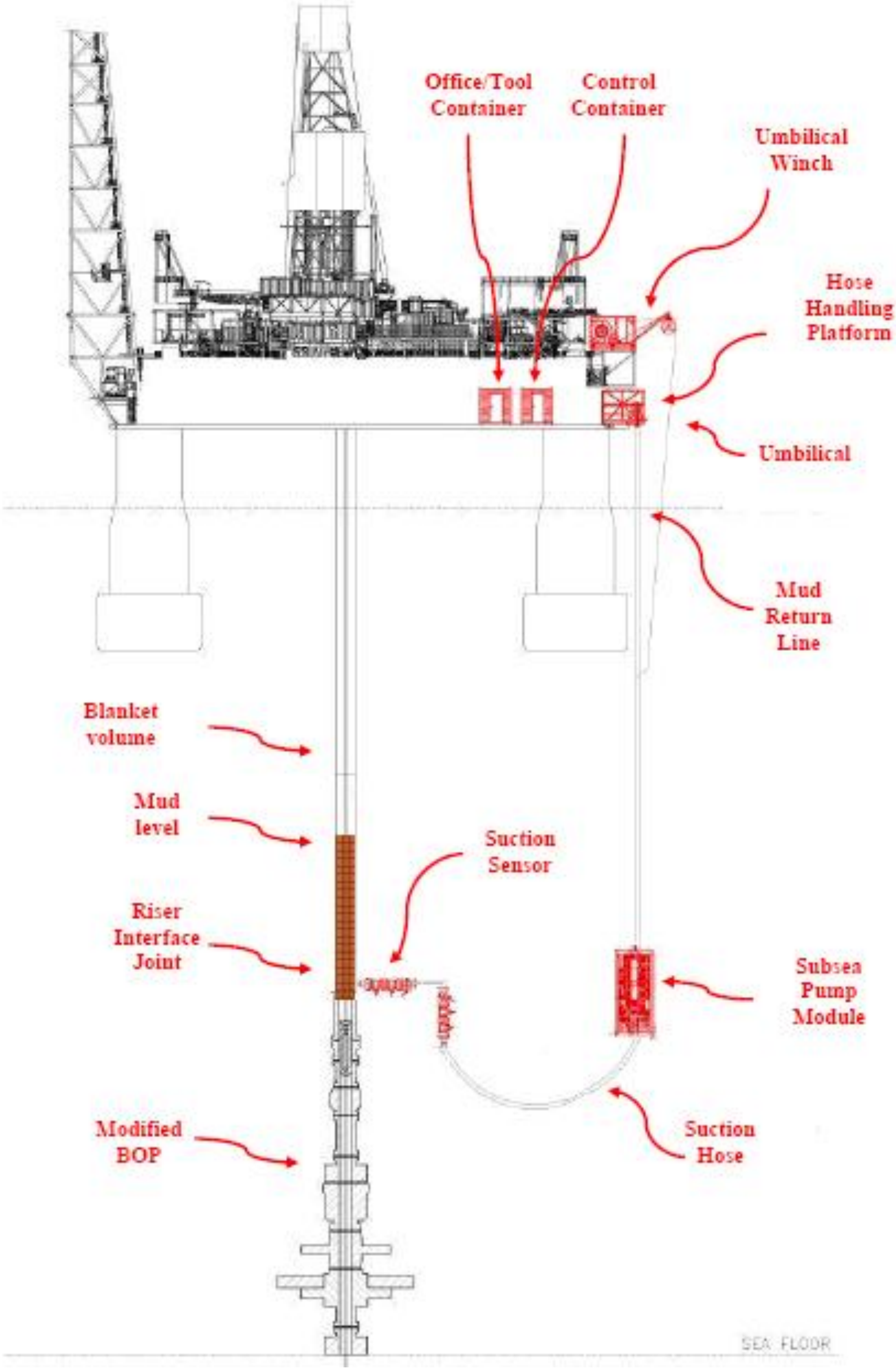

Figure 11: CMP system layout (Østvik, 2011)

WELLPLAN™

General Information

WELLPLAN™ is a component of Landmark's Engineer's Desktop™ developed by Halliburton™. This software allows the user to identify potential problems during the drilling and completion process in terms of wellbore design (Halliburton). Integrated technologies enables the user to study and evaluate BHA, torque and drag, stuck pipe, cementing, hydraulics and well kick scenarios. For this particular report the main focus will be on the torque and drag and hydraulics modules. WELLPLAN™ Torque and Drag Analysis software provides knowledge of anticipated loads for drilling and casing operations, and as a result it can be determined if the selected rig has good enough mechanical specifications to handle the well design requirements. WELLPLAN™ Hydraulics software delivers all the necessary tools for the user to study and design well hydraulics. For instance will the user be able to study ECD with regards to pore pressure and fracture pressure problems, and to select different flowrates to optimize hole cleaning. In this thesis a deep water field located in the Gulf of Mexico has been selected and chosen as a base case. With the tools available in WELLPLAN™ different parameters will be changed in order to find the theoretical drilling limit for two different rigs when considering torque and drag and ECD.

Drillpipe

WELLPLAN™ has a large selection of drillpipes stored by default into catalogues in the software. However, since WELLPLAN™ is a few years old and developed by one company alone it will not be up to speed with other companies' development process when it comes to drillpipes. As a result the available selection of drillpipes are outdated and not suited for the requirements requested in this thesis. Even though WELLPLAN™ release patches with different updates at a regular basis the default drillpipe selection fails at producing any significant results for this case. As a solution to this WELLPLAN™ allows you to add your own drillpipe catalogues from external sources.

When considering which type of drillpipes to use for a given project, it is important to evaluate whether or not the given parameters are able to handle the project at hand. Some important parameters to look at when deciding would be tensile and torosional strength and make-up torque. Values for these parameters are found in so called drillpipe charts provided by the manufacturer. For this particular case it was decided that a drillpipe selection provided by VAM drilling™ had the necessary specifications required for the simulations run in this thesis. Data was provided to me by Alasdair Fleming of Lyngaas TMC under Statoil approval. The specifications for the different drillpipes are found in Table 1 and Table 2.

Drill pipe	Grade	Class	Weight (lbs/ft)	Torosional Strength (ft-lbs)	Tensile Strength (lbs)	Make-up torque (ft-lbs)
5” NC50 VAM EIS	S-135	P	22.62	58,100	561,000	30,135
5 7/8” VAM Express VX57	S-135	P	26.70	92,500	757,000	48,300
6 5/8” FH	S-135	P	27.70	108,000	760,000	54,700
6 5/8” VAM Express VX65	S-135	P	31.20	134,000	976,000	70,000
6 5/8” FH	S-135	P	34.02	144,000	1,060,000	67,000
6 5/8” FH	Z-140	P	50.46	199,300	1,615,000	71,400

Table 1: Drillpipe chart (drilling, 2009)

Drill pipe	Pipe ID (in)	Wall thickness (in)	Tool-joint OD (in)	Tool-joint ID (in)
5” NC50 VAM EIS	4.276	0.290	5.844	3.250
5 7/8” VAM Express VX57	5.045	0.332	6.688	4.250
6 5/8” FH	5.901	0.290	8	4.250
6 5/8” VAM Express VX65	5.675	0.380	7.906	5.250
6 5/8” FH	5.581	0.418	8.500	4.250
6 5/8” FH	5.812	0.813	8.500	4.000

Table 2: OD and ID from drillpipe chart (drilling, 2009)

The different 6 5/8” drillpipes were tested with respect to torque and drag limitations in WELLPLAN. From the hook load chart we read the bottomhole values and put them into Table 3. The Grant Prideco pipe is the strongest one, but it is having problems regarding torque and drag even before we have tried to extend the trajectory and will not be suited for the case study. After evaluating data from these three tables and performance in WELLPLAN^{TM} the 34.02 lbs/ft (61.65 kg/m) is chosen for further case and sensitivity studies.

	6-5/8 IEU X 27.70 lbs/ft	6-5/8 IEU X 31.20 lbs/ft	6-5/8 IEU X 34.02 lbs/ft	6-5/8 Grant Prideco 50.46 lbs/ft
Trip in max [kN]	2616,9	2693,4	2829,1	3118,6
Trip out max [kN]	3772,1	3848,6	3984,3	4273,9
Rotate on bottom max [kN]	3118,9	3195,4	3331,1	3602,6
Rotate off bottom max [kN]	3198,9	3275,4	3411,1	3700,6
Maximum yield [kN]	3924,3	4804,4	4940,1	4444,9
Minimum buckle [kN]	2623	2699,5	2835,2	3124,8

Table 3: Bottomhole hook load values for 6 5/8” DP (WELLPLAN).

Case study

Rig specifications

The different well trajectories presented in the case studies will be compared to the limiting factors of the rigs Maersk Developer and Transocean Discoverer Americas. Both rigs are well suited for the harsh, deep water environments in the Gulf of Mexico and are operated by Statoil. Specifications for both rigs are presented below, while additional information about the pump system of each rig can be found in Appendix A.

Maersk Developer

The Maersk Developer was the first in a series of three highly advanced Deepwater Development Semi-submersible rigs constructed for Maersk Contractors in Singapore. It is optimized for field development work, but new design makes it a cost efficient exploration unit as well. It is said to be substantially larger and more sophisticated than existing rigs operating in this segment, which make it particularly well suited for deep and complicated well areas like Brazil and the Gulf of Mexico (RIGZONE, 2008).

Specifications	
Rated water depth	75 to 3,000m
Rated drilling depth	min. 10,000m
Hull dimension	117m*78m*37m
Variable load	13,500 t
Power supply	Wärtsilä 16V26,8*4,750kW
Well control equipment	15,000psi, 18 ¾"BOP; Six cavity BOP stack
Cranes	1 ea 50m boom, 50 t 1 ea 50m boom, 160t
Cement pump	15,000 PSI (on free placement)
Hoisting equipment capacity	2,500,000lb
Drawworks	4,600hp
Top drive	2,000hp 95,000 ft-lbs (torque)
Mud pumps	4*2,200hp, 7,500psi
Rotary table	Varco 1.5367m diameter
Bulk mud capacity	$4*170m^3$
Bulk cement capacity	$4*170m^3$
Liquid mud capacity	18,900bbl
Accommodation	180 people

Table 4 (Maersk drilling)

Transocean Discoverer Americas

Transocean discoverer Americas is a double hulled dynamically positioned Enhanced Enterprise class drillship capable of operating in moderate environments and ultra-deepwater (Transocean). It is currently working on operations in the GoM for Statoil Gulf of Mexico, under a four year drilling contract that started in 2009. Discoverer Americas features Transocean's patented dual-activity drilling technology. This enables parallel drilling operations, which saves time and money in deepwater well constructions. Additionally it features an enhanced top drive system, high-pressure mud-pump system and other unique features allowing target wells up to 40,000 feet of total depth (Transocean).

Specifications	
Rated water depth	3,657m
Rated drilling depth	12,191m
Length*Width*Depth	255m*38m*19m
Variable load	20,000 mt
Main Power	14 cylinder engines rated 7,000 kW each, 6 Siemens generators rated 6,456 kW.
Well Control Equipment	15,000psi, BOP: 3 x 18¾ inch 15K compact double ram preventer; 18 3/4 inch 15K Super HD wellhead connector.
Deck Cranes	Lift radius 7.8m to 45m
Derrick	68.9m*24.4m*24.4m base Racking 2,500lbs
Drawworks	2* 1,000ST with 2-inch line
Top drive	2*1,250ST 101,200 ft lbs (torque)
Mud pumps	5*NOV Hex 240, 7,500psi
Rotary table	NOV 1.9177m hydraulic forward, NOV 1.5367m aft
Bulk mud capacity	453m^3
Bulk cement capacity	453m^3
Liquid mud capacity	20,000bbl
Accommodation	200 berths

Table 5 (Transocean)

Torque and Drag

Torque and drag simulations are used to determine whether or not the tubular design, both drillstring, casing, liner, workover/completion and surface equipment can fulfill the well objectives. These evaluation criteria include max pull, compression, stresses and critical buckling loads among others, which will be discussed more in detail in the case studies. Through this simulation and analysis we can determine the adequate weight on bit capacity and adequate torque capacity, if the preferred bit is run efficiently throughout the run and if BHA composition can be changed to increase weight and/or torque available at the bit (Sangesland, Xiaojun He, & Islam, 2011).

Torque is defined as the turning force that is applied to a shaft or other rotary mechanism to cause it to rotate or tend to do so, and it is measured in units of length and force (OilGasGlossary.com). Drag is the equivalent to the hook load during run in hole and pull out of hole, and is dependent on the friction factor.

Torque and Drag Models

For a straight borehole:

$$F_2 = F_1 + w * (\cos\theta +/- \mu\sin\theta)$$

The plus sign is used for pulling and the minus sign for lowering of the string.

$$M_2 = M_1 + \mu * w * r * \sin\theta$$

Where:

F = Force

M = Friction torque

r = radius of pipe/tool joint

μ = Friction factor

w = unit weight of pipe (submerged)

$$w = \beta * m * g * \Delta L$$

β = buoyancy factor

$$\beta = 1 - \frac{A_0 * \rho_0 - A_1 * \rho_1}{m}$$

A_0 = cross section area of pipe OD

A_1 = cross section area of pipe ID

ρ_0 = Fluid density outside of pipe

ρ_1 = Fluid density inside of pipe

With conditions for sliding being:

$$\cos\theta = \mu * \sin\theta \ and \ \theta \leq \tan\left(\frac{1}{\mu}\right)$$

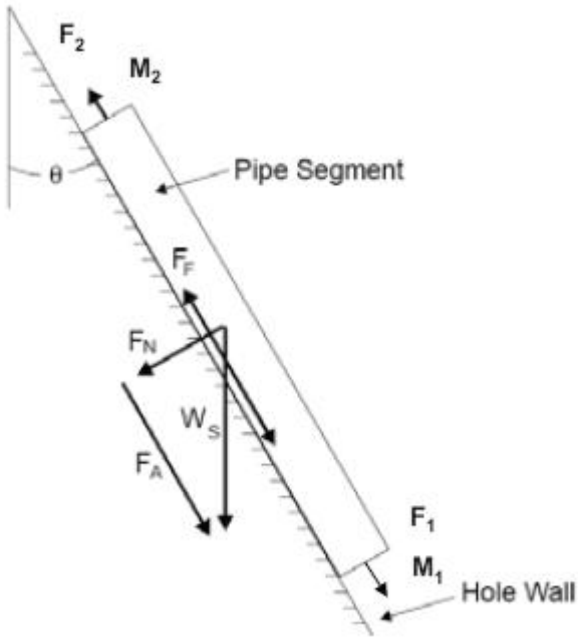

Figure 12: Straight borehole section (Sangesland, Xiaojun He, & Islam, 2011).

For a curved borehole - Analytical

Most computer programs use a discrete model, so I won't go in depth on this method.

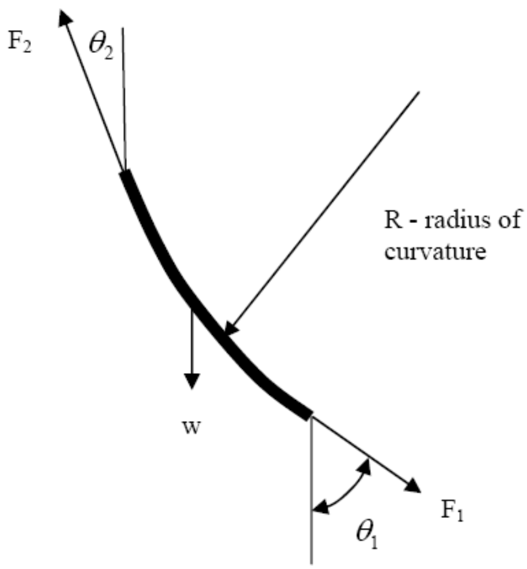

Figure 13: Curved borehole section (Sangesland, Xiaojun He, & Islam, 2011).

$$F_2 = F_1 * e^{\mu(\theta_2 - \theta_1)} = F_1 * e^{\mu\frac{2*\pi*\theta}{360}}$$

For a curved borehole – Discrete

Borehole trajectories are seldom smooth, as desired by the analytical model, with continuous changes in inclination and azimuth angles. Therefore the discrete model is for accurate, and hence used in most computer programs.

$$F_2 = F_1 + w_{curve} * \cos\bar{\theta} +/- \mu * N$$

Where "+" indicates pulling of the pipe and "-" lowering of the pipe.

$$M_2 = M_1 + \mu * r * |N|$$

Where: $$N = \sqrt{(F_1 * \Delta\varphi * \sin\bar{\theta})^2 + (w * \sin\bar{\theta} + F_1 \Delta\theta)^2}$$

For Δϕ=0 we have no changes in the azimuth direction; $N = w * \sin\bar{\theta} + F_1 * \Delta\theta$

$$\Delta\theta = \theta_2 - \theta_2 (radian)$$

$$\Delta\varphi = \varphi_2 - \varphi_1 (radian)$$

$$\bar{\theta} = \frac{\theta_2 + \theta_1}{2} (degree)$$

$$\bar{\varphi} = \frac{\varphi_2 + \varphi_1}{2} (degree)$$

Additionally it is worth mentioning that a negative value in the equation $\Delta\theta = \theta_2 - \theta_2$ means that the normal force N is reduced, since F will tend to lift the drillstring off the low side of the well in the build-up section when POOH. In a drop off section, the result will be the opposite.

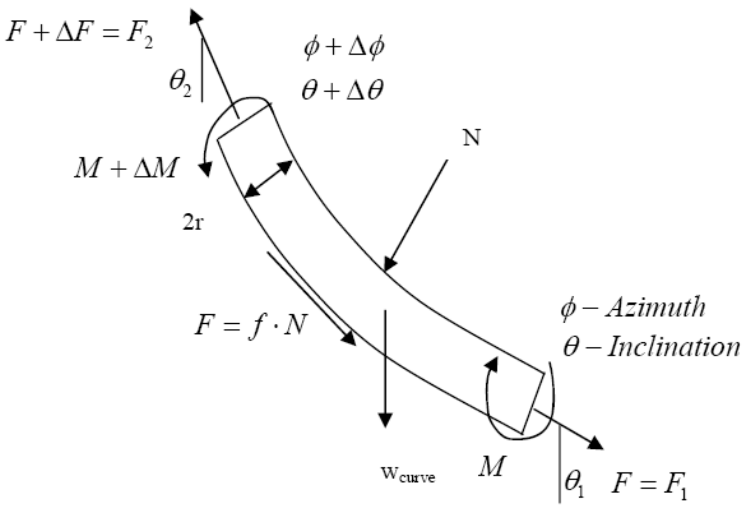

Figure 14: Torque and drag for curved hole (Sangesland, Xiaojun He, & Islam, 2011).

Simplified Calculations

Using simplified versions of the equations given above, we can calculate how the torque and drag will increase for different cases. With data from the base case used in this thesis, we can find how the torque and drag will increase with horizontal and vertical extensions of the well trajectory.

Given data:

μ	=	0.38
OD_{TJ}	=	148.43mm
OD_{DP}	=	127mm
g	=	$9.81 m/s^2$
m_{min}	=	33.66kg/m
m_{max}	=	61.65kg/m

$$\beta = 1 - \frac{\rho_{mud}}{\rho_{steel}} = 1 - \frac{1.7}{7.85} = 0.783$$

Horizontal Extension Calculation

When calculating the torque for an horizontal extension we assume that there will be no inclination. From WELLPLAN™ we obtain the maximum rotate on/off bottom values and calculate the torque for horizontal extension, assuming that the increase is linear. It is also assumed that when we extend the well horizontally the torque increase will only be affected by the 5" drillpipe and that only the open hole friction factor will be acting on the drillpipe. The result we get will later be compared to those calculated in WELLPLAN to see how the theory matches the simulations.

Simplifying the torque equation for horizontal extension we get:

$$Torque = \beta * m * g * \mu * \frac{OD_{TJ}}{2} = 0.783 * 33.66 * 9.81 * 0.38 * \frac{148.43}{2} * \frac{1}{1000}$$
$$= 7.29\ Nm\ per\ m$$

Some simulation software will use the diameter of the drillpipe when calculating torque, using that value we get:

$$Torque = \beta * m * g * \mu * \frac{OD_{DP}}{2} = 0.783 * 33.66 * 9.81 * 0.38 * \frac{127}{2} * \frac{1}{1000}$$
$$= 6.24\ Nm\ per\ m$$

The drag equation when simplified becomes:

$$Drag = \beta * N * \mu = \beta * m * g * \mu$$

However, it is important to consider which part of the drillpipe we extend, as the weight of the 6 5/8" drillpipe is nearly twice of the 5" pipe. The maximum drag increase will occur if we only extend the 6 5/8" pipe:

$$Drag_{max} = 0.783 * 61.65 * 9.81 * 0.38 = 180{,}0N\ per\ m$$

Likewise the minimum drag increase occurs when only the 5" pipe is extended:

$$Drag_{min} = 0.783 * 33.66 * 9.81 * 0.38 = 98{,}3N\ per\ m$$

ECD

General

Equivalent Circulating Density is defined as the increase in bottomhole pressure expressed as an increase in pressure that occurs only when mud is being circulated (OilGasGlossary.com). Due to friction in the annulus when mud is being pumped, the bottomhole pressure will be slightly higher than when the mud is not being pumped. Although the pressure increase is small it is of great significance as ECD is an important parameter when it comes to avoiding kicks and losses. ECD is strongly dependent on total annular pressure loss and is a function of the pipe length and width. ECD will increase with increasing outer diameter of the pipe due to less annular clearance and higher velocities. Wells with a narrow window between fracture and pore-pressure gradient are extra sensitive to ECD. ECD can be expressed as (Sangesland, Xiaojun He, & Islam, 2011):

$$ECD = ESD + \frac{\Delta P}{g * TVD}$$

Where: $$\Delta P = total\ annular\ pressure\ loss$$

$$g = gravitational\ constant$$

$$TVD = true\ vertical\ depth$$

$$ESD = \frac{Static\ P_r}{g * TVD}$$

The equivalent static density (ESD) is found when the pumps are turned off and will be similar to the mud weight value.

ECD effects will be more severe in deep water and ERD wells because of higher flow rates required to clean the hole, and also because of longer hole sections (Agbaji, 2010). Some of the direct effects of ECD include lost circulation, casing collapse, wellbore instability and reservoir damage. Additionally the surge pressure will create a “piston force” that behaves like a drag, when doing marginal casing runs this can be a crucial factor (Sangesland, Xiaojun He, & Islam, 2011). There are also some indirect effects that might occur due to ECD. When considering hole cleaning a reduction in some parameters will limit the cleaning process and start a vicious cycle where more cuttings causes higher ECD, which causes additional reduction of the parameters that leads back to more cuttings and so on. If these parameters are reduced it might affect torque and drag as well as the drilling performance.

DGD technology is able to compensate for some of the problems associated with ECD by removing the riser from the system (figuratively and/or literally depending on which DGD method is used). This will allow the pressure at the seafloor to be lower and it is easier to navigate in the window between formation-fracture pressure and formation-pore pressure (Figure 36). As a result less casing strings are needed, which will lower the total annular pressure loss and fluid velocity and thus reduce ECD. Additionally DGD will allow for a greater variety of mud weights and types to be used, which will help with ECD control.

Reservoir Information

The sensitivity study performed in this thesis is based on data from the Wilcox formation provided by Statoil. The formation is located in the northwestern GoM coastal plain covering a total area of roughly 88060km^2 (Lewis, et al.), both onshore and offshore. Wilcox is tied to the Paleocene and Eocene epochs (Internal) and the main discoveries are found in turbidite sands that have been deposited in lower slope channels and ponded fans to regionally extensive basin floor fan systems. Most parts of the targeted Wilcox reservoirs are located beneath allocthonous salt canopies ranging from 7,000 to 20,000feet in thickness, which mean that complex drilling programs and high-cost rigs are a necessity. It is estimated that the Wilcox trend has the potential for recovering from 3 to 15 BBO from current discoveries and additional untested structures (Lewis, et al.).

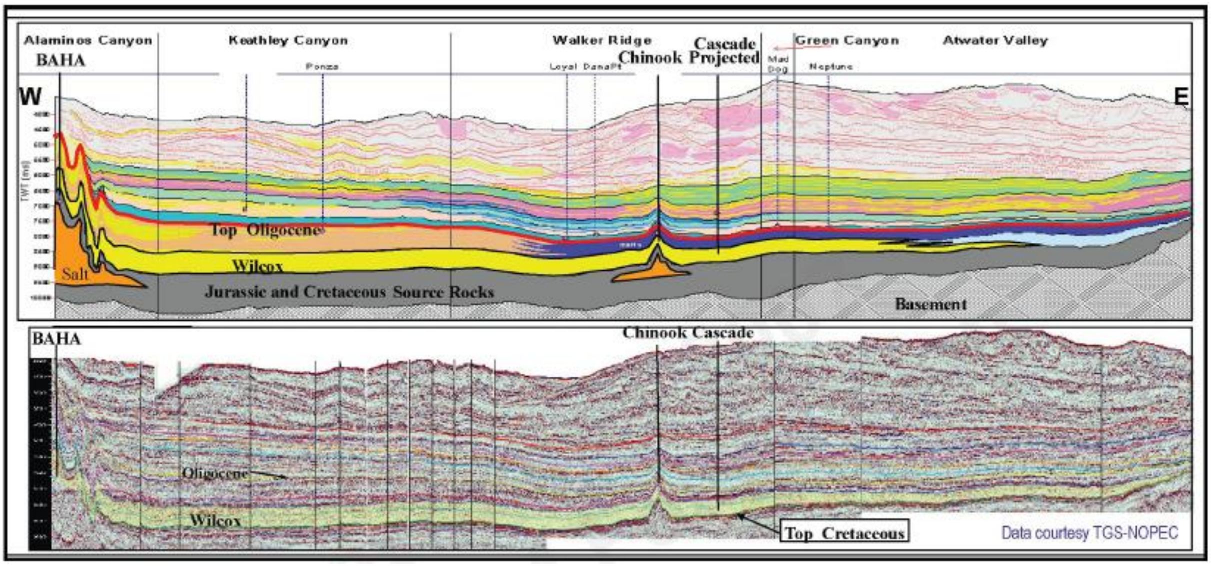

Figure 15: Example of a regional 2D seismic transet and interpreted cross section area of the Wilcox trend (Lewis, et al.).

Wilcox reservoir rocks are characterized by low permeability (measured core permeability typically less than 10 md) and core porosity ranging from 15% to 25%. Within the given porosity range, the permeability can vary over three orders of magnitude, which provides a difficult challenge for accurate permeability modeling as this order should be less than one. Without going into details on how this method works; electrofacies have been generated to group rocks with similar fluid flow properties as a solution to this problem. For the lower part (Wilcox 2) it has been observed a generally higher permeability then in the upper part (Wilcox 1). This is due to differences between sandstone depositional facies, texture, and grain composition. Some of these differences can be observed in Figure 16. A typical Wilcox reservoir rock is described as very fine-grained, lithic-rich, thinly interbedded to massive sandstone.

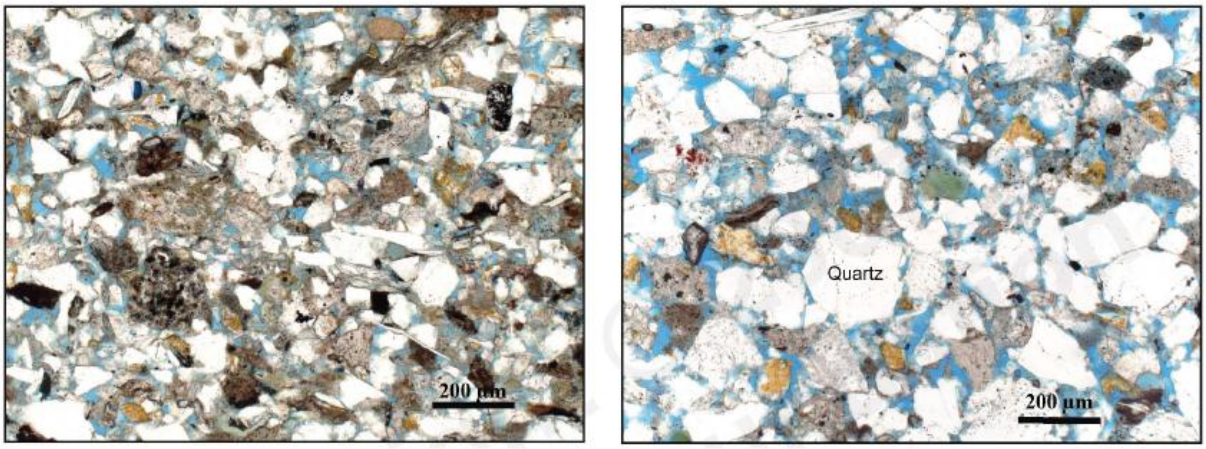

Figure 16: Photomicrographs of Wilcox 1(left) and Wilcox 2(right) (Lewis, et al.).

Base case

The Wilcox data provided by Statoil has been modified and put into WELLPLAN by Alasdair Fleming of Lyngaas TMC. From these data one well has been chosen as a base case and modified further to test how far it is possible to drill in WELLPLAN in terms of limitations to torque, drag and ECD among others. The chosen well path has a trajectory with measured well depth of 11563.75m, and is going into the Wilcox 1 part of the reservoir. At a water depth of 2300m, this is categorized as an ultra deep field, which provides additional challenges as there are very few similar projects to compare with. When testing the limit of the different parameters while extending the well horizontally, vertically or a combination of both no changes are made to the pore and fracture data or the thermal gradient. If the target depth was below given pore and fracture data depth it is assumed that the data will remain constant. The same goes for the geothermal gradient, which is set at 2,73°C per 100m increase in TVD. Seawater temperature at the mud line is set to 4°C.

The currently most used mud type in GoM is synthetic oil-based mud. To give the most accurate results the Herschel-Buckley rheology model is used. As default a mud with density of 1700 kg/m^3 will be used to best represent mud used in similar projects. Fluid data can be seen in Figure 17.

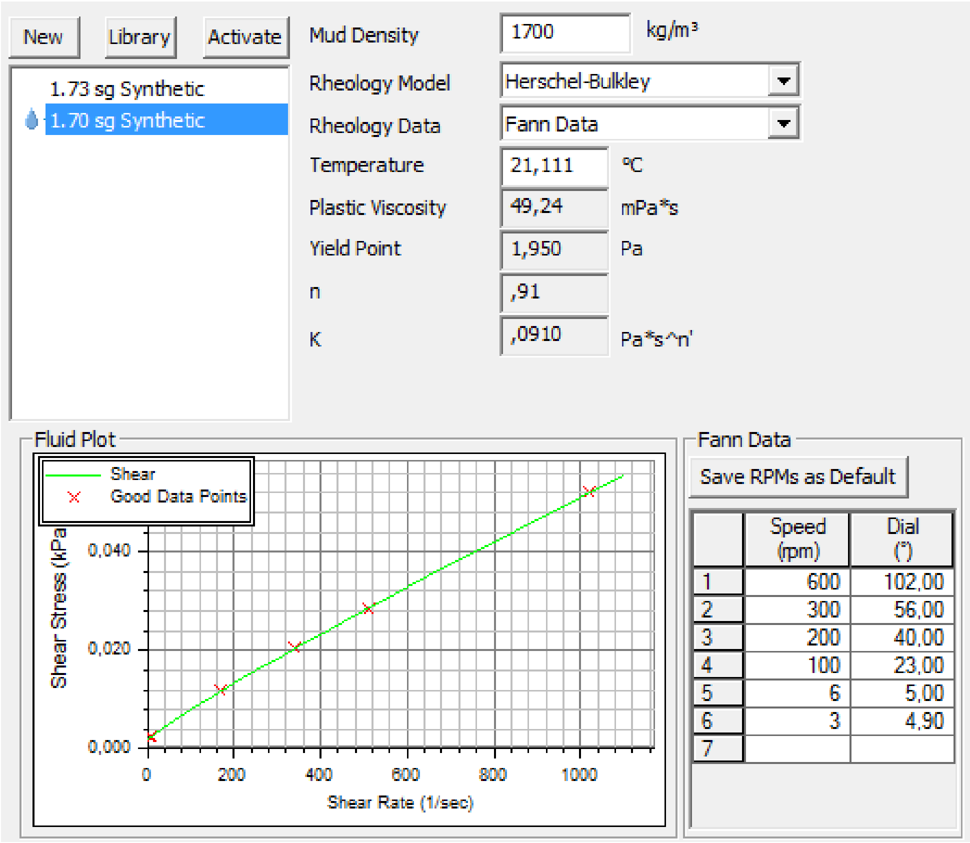

Figure 17: Fluid properties for 1.70sg synthetic mud (WELLPLAN)

When testing the limit of parameters for horizontal and vertical extension we will keep the well trajectory as similar to the base case as possible. This means that for the horizontal extension the well will be exactly the same down to measured depth, and then we add length horizontally. For the vertical extension we add length to the true vertical depth above the point where inclination starts, meaning the well trajectory during inclination will look exactly the same.

Currently there is no accurate data available on which friction factor that should be used in these reservoir conditions. The regular values of 0.18 for cased hole and 0.24 for open hole (Sangesland, Xiaojun He, & Islam, 2011) will not be realistic for this scenario and higher values are chosen. A more in depth discussion on this will be presented later in the thesis. Due to the lack of data an absolute worst case scenario is assumed, meaning 0.33 for the cased hole and 0.38 for the open hole section. This value was estimated together with Alasdair Fleming, based on his work with similar wells. Values associated with torque and drag and hydraulics modules are in general estimations based on previous cases that Alasdair has been working on, and the default settings used can be found in Appendix A. Any changes done to the default settings will be explained in the sensitivity study.

For all the different simulations the same BHA has been used. This is due to the fact that the BHA will have next to no effect on the torque and drag simulations in WELLPLAN. The assembly has been made by Alasdair and its components can be seen in Figure 18. A table with all the data used in this BHA can be found in Appendix A.

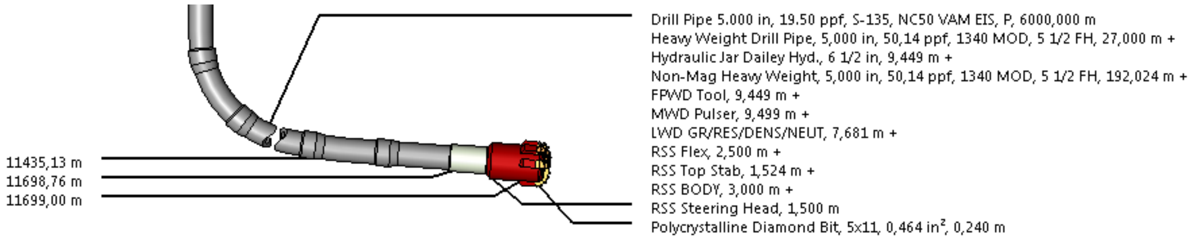

Figure 18: Base case BHA made by Alasdair (WELLPLAN).

Torque, Drag and ECD Limitations

Study 1: Horizontal Extension

To start off the sensitivity study and get a closer look on how the different parameters would react, the wellpath was extended from 11563.7m to 12150m in horizontal direction. With more drillpipe it is safe to assume that tripping in and out will increase as the total weight increases. Also, an increase in rotating on and off bottom should be observed since torque will increase as well. Compared to the torque graph for the base case (Figure 37) rotate on and off bottom has shifted to the right due to an increase in torque. From Figure 19 we can see that the torque limit for the bottom drillpipe is exceeded in the depth interval from 5486m to 7095m (values read from WELLPLAN). This tells us that somewhere along the depth interval, the string buckles. In order to prevent this, the 5" drillpipe needs to be set below 7095m. Another way to fix this problem is to use a heavier mud, which will decrease the total torque and shift rotating on/off bottom towards the left depending on how much we increase the mud weight (Table 13). By applying DGD technology increase in mud weight could be used as an alternative to changing setting depth. The new Torque chart can be found in Appendix B.

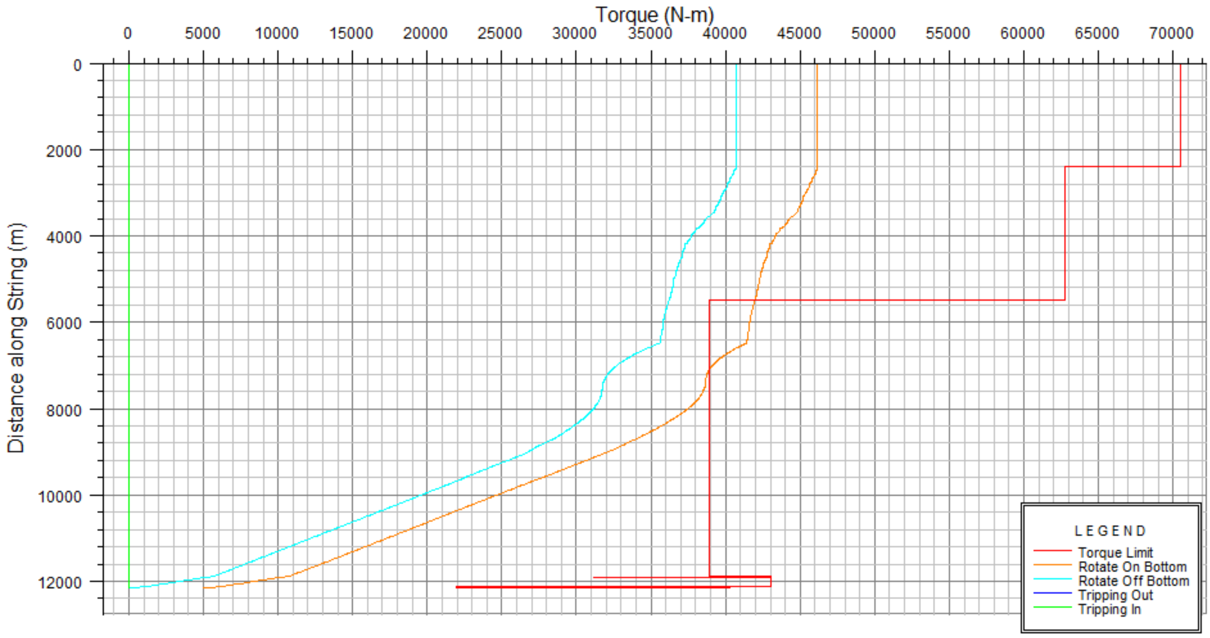

Figure 19: Torque graph for 12150m horizontal extension (WELLPLAN)

When the new depth of the bottom drillpipe has been set, we need to look into the hookload chart to see if any buckling or deformation might occur. From Figure 20 we can see that tripping out is well within its boundaries, but tripping in is crossing minimum weight helical buckling at approximately 11900m. To keep tripping in higher than minimum weight for helical buckling we can set the casing 9 5/8" 1000m deeper and thus reducing the total friction for the operation (Figure 39).

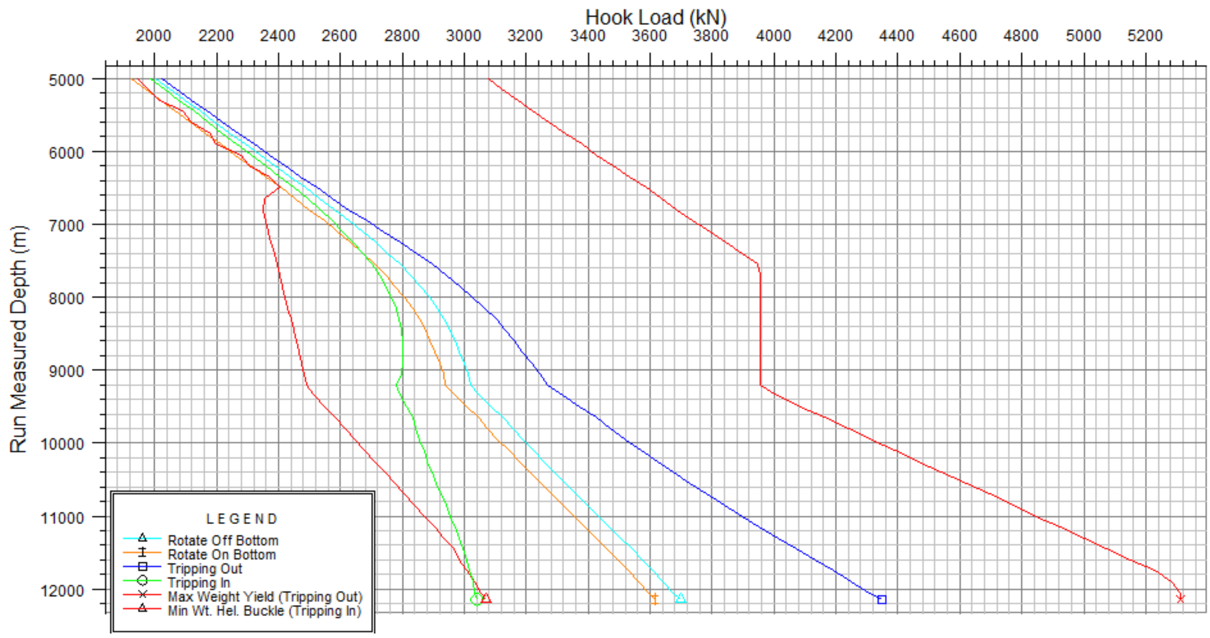

Figure 20: Hook load chart for 12150m horizontal extension (WELLPLAN)

Now that the torque and drag values are kept within their limits we need to take a closer look at the hydraulics module, to see whether or not it can handle the given depth. It is important to note that we might get two slightly different results at the given depth as Transocean Discoverer Americas and Maersk Giant have different mud pump systems (Table 16 and Table 17), as these systems provide many of the parameters needed for the hydraulics module. First off we take a look at the pressure losses at different pump rates in Figure 21. Here one of the main differences between Transocean and Maersk are shown when it comes to mud pump systems. Transocean has the possibility to work with maximum surface working pressures peaking towards 6700psi (46195 kPa) whereas Maersk is peaking somewhere along the line of 6000psi. We will use the peak pressure as our parameter in these studies since it will tell the max pump rate for allowable system pressure loss. It is not realistic that the rigs can operate at a constant peak pressure for a longer period of time, so the constant surface working pressure would typically be 6000psi for Transocean and maybe as low as 5000psi for Maersk. At a pump rate of approximately 2.26m^3/min, the system pressure loss vs. pump rate exceeds the maximum surface working pressure for Maersk (Figure 21).This could lead to problems regarding ECD and should be avoided. The same value will be greater for Transocean and is ignored for now.

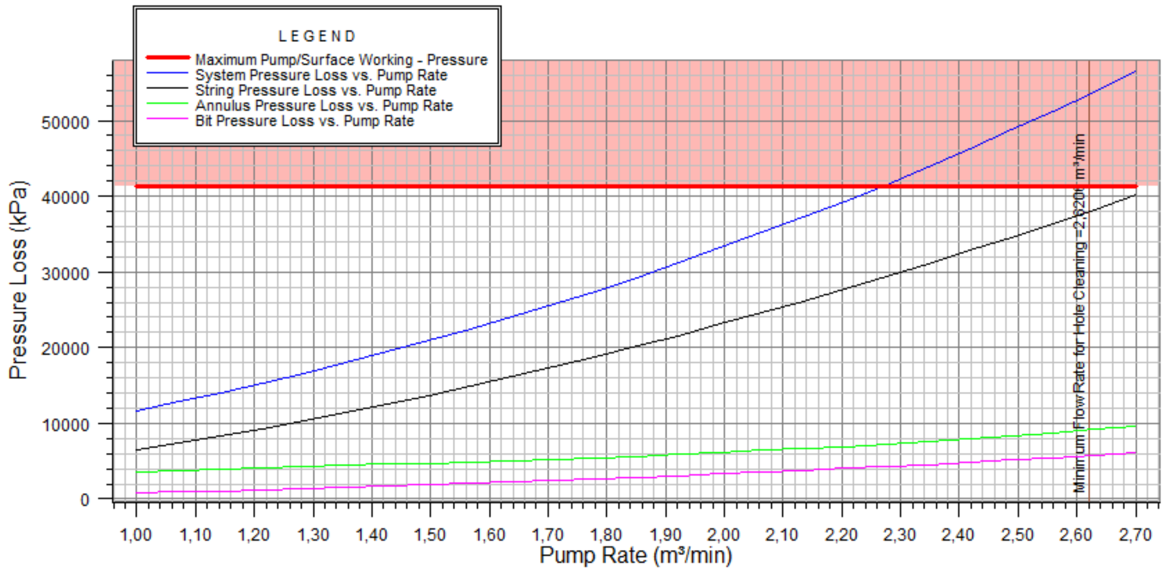

Figure 21: Pump rate range pressure loss for Maersk at 12150m horizontal extension (WELLPLAN).

On the right hand side of the figure we can see that the minimum flow rate for hole cleaning is at 2.62 m^3/min, meaning that we have to go well beyond the maximum surface working pressure in order to clean the hole. However, by investigating the hole cleaning graph we observe that the given value for hole cleaning from the previous figure is that high only above the mud line. This flow rate can be compensated for by using a booster pump, meaning that the actual minimum flow rate is found below the mud line. DGD and MPD are both methods that can be used for this purpose, as they will use a subsea pump or other method to compensate for the flow rate requirement above the mud line. On Figure 22 the given minimum flow rate is 1.3123m^3/min, which in this case turned out to give the same result for Transocean (Figure 40). Hole cleaning parameters can be found listed as transport analysis data in Figure 35 (Appendix B). As the actual minimum flow rate is half the value of what was originally assumed the system pressure loss is kept well within its boundaries, and both Maersk and Transocean could operate at a pump rate of 2.0m^3/min. The new figures for pressure loss are found in Appendix B.

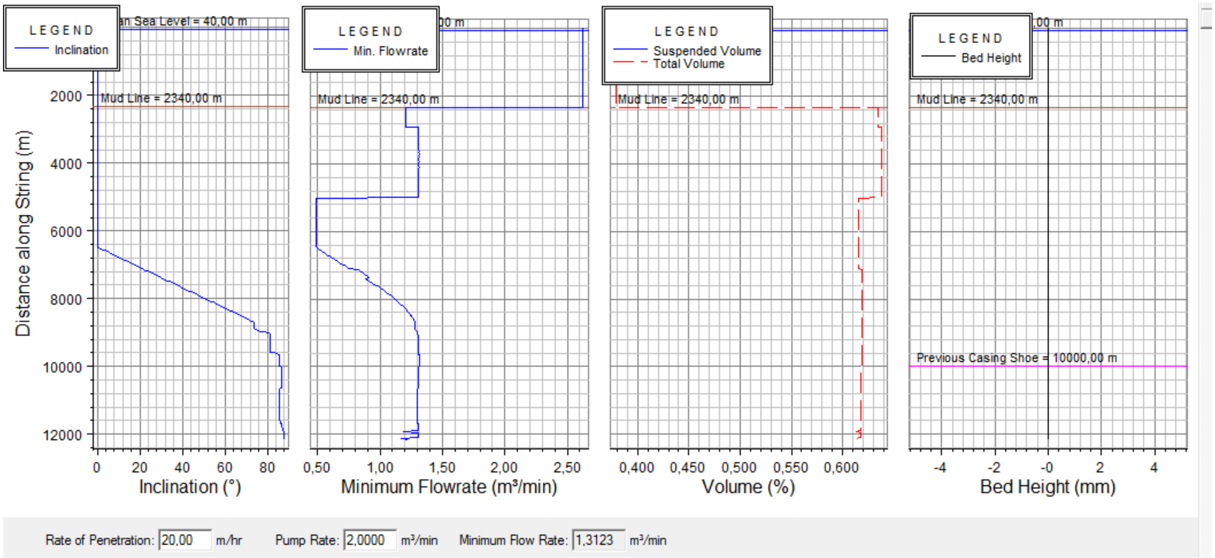

Figure 22: Hole cleaning operational graph for Maersk at 12150m horizontal extension (WELLPLAN)

The first major problem of this case is encountered when looking at the distance along string vs. ECD graph (Figure 23) when operating with a pump rate of 2.0m^3/min. Within the interval from previous casing shoe at 10000m to the end of the hole section at 12150m the annulus ECD is of greater value than the fracture gradient. This could lead to problems regarding lost circulation and reservoir damage and should be avoided at all cost. When reducing the pump rate to the minimum flow rate required for hole cleaning the annulus ECD is below the fracture gradient down to approximately 12000m (Figure 43). This means that pump rate adjustments alone are not sufficient to handle the ECD, so we have to go back and change some other parameters in order to be able to drill down to this depth.

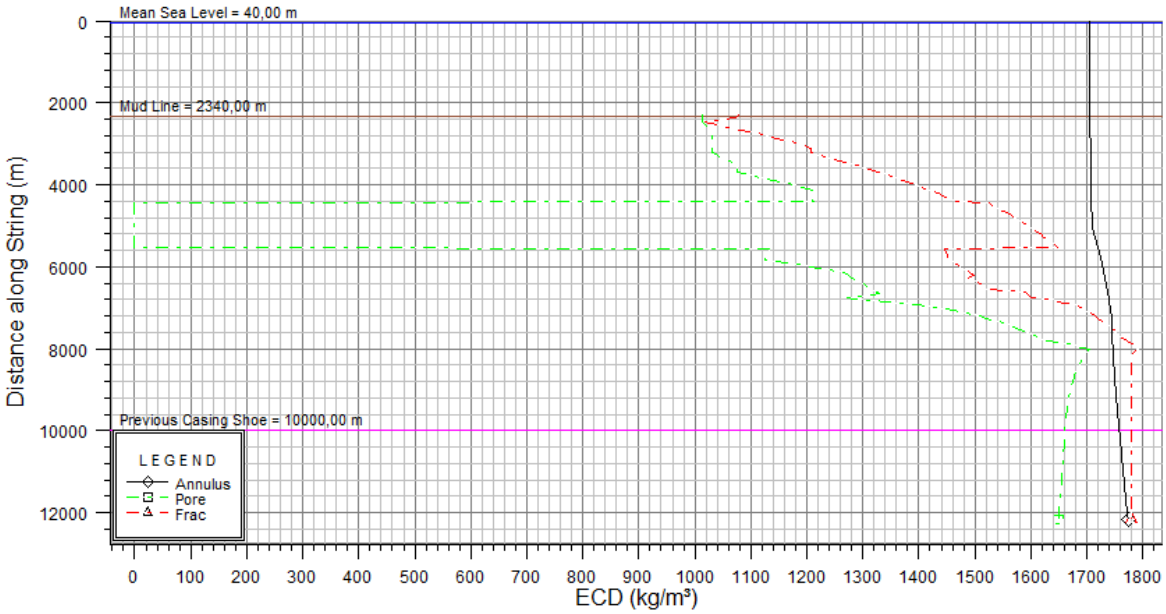

Figure 23: Maersk ECD vs. Depth at 12150m horizontal extension, pump rate at 2.0m^3/min (WELLPLAN).

Another solution to this is to add an additional larger casing in the hole section editor and "turn" the 9 5/8" casing into a liner. This way we create a larger flow path which will reduce the fluid velocity and reduce the back pressure. As a result of decreased back pressure we achieve less total pressure and ECD will decrease. By adding 13 3/8" casing down to 5000m the annulus ECD will move in between the pore and fracture gradients (Figure 44) and problems associated with ECD is prevented.

These small adjustments have been sufficient to extend the well trajectory an additional 450m in horizontal direction, and it has pushed some of the parameters to their limits. By implementing additional changes on the previously tested parameters we will try to find an optimal solution to how far it is theoretically possible to extend this well. It is important to note that this study is solely based on the tools available in WELLPLAN, and that some assumptions are made in order to make this possible. In study 1 the focus will be on extending in horizontal direction only, while study 2 focuses on vertical extension.

As a start we can extend the well trajectory to 13000m. Considering how close for instance tripping in is to its limit, it is likely that we will have to stop the operation before this length is reached. By adjusting the different parameters further we will try to get as close to 13000m as possible, and if the adjustments can get us past 13000m we will push towards a new target depth. The procedure will be the same as at 12150m depth, starting out with the torque and drag module where we analyze hook load among others before cross checking with the hydraulics module if all parameters are kept within limits.

At the torque graph we can observe that the torque limit for the 5” pipe needs to be set below a certain depth so it won’t cross the rotate off bottom line. By right clicking on the graph and choosing the option graph to grid, we find that the minimum depth for the 5” pipe is approximately 8836m, where depth is meant as length of the well trajectory. When that is taken care of, we get a graph looking like Figure 24. We might need to make some depth adjustments for the different pipes, but we will leave it like this for now.

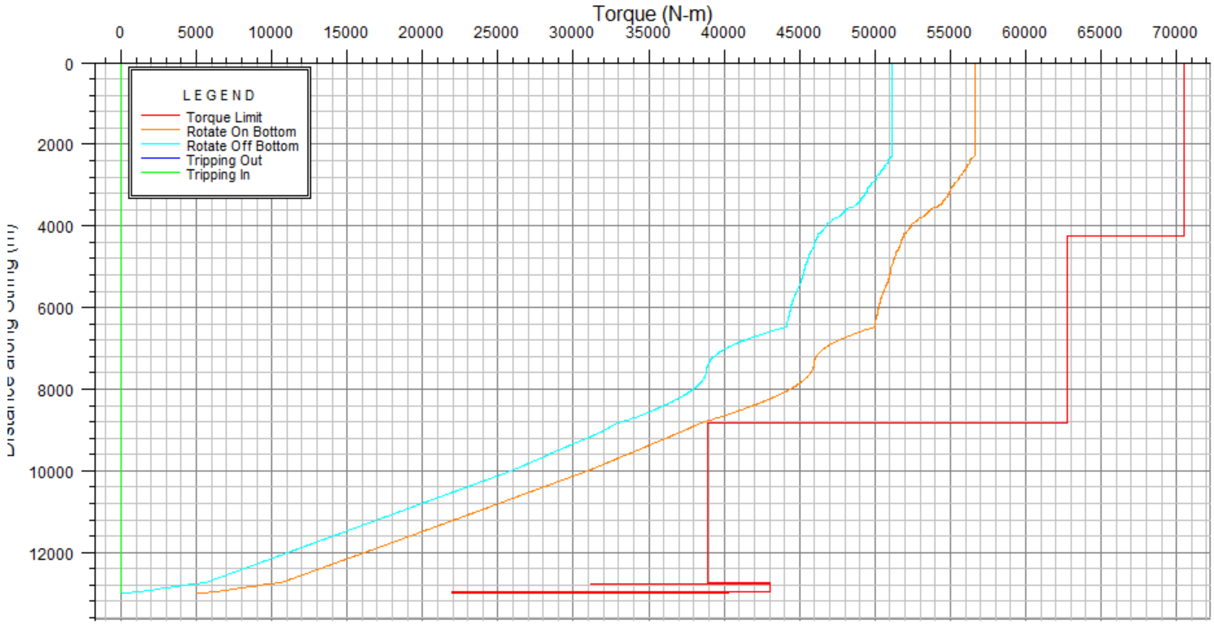

Figure 24: Torque chart for 13000m horizontal extension. (WELLPLAN)

From the new hook load chart (Figure 45) tripping in crosses the helical buckling line at 12470m and buckling occurs. To prevent this from happening we need to alter the drill pipe lengths, increase casing depth or both. Increasing the casing depth is helpful as the cased section has a smaller friction factor than the open hole section, but is not a good economical option. Since the 5” pipe has to be set below 8836m altering only the drillpipe at this time will have no effect, which means we need to look into editing the hole section first. Even when we exclude the entire open hole section and set the 9 5/8” casing down to 13000m WELLPLAN predicts buckling around 12900m (Figure 46), which will be the current theoretical maximum length. However, casing the entire well path is not a realistic option so we will operate with 10000m casing depth for now as we investigating the hydraulics.

The hole cleaning graphs were close to identical for Transocean and Maersk, both requiring a minimum flow rate of 1.3122m^3/min (Figure 47) to clean out the hole. With the new actual minimum flow rate both are well within surface pressure limits when operating with a pump rate up to 2.0m^3/min as can be seen in Figure 48 and Figure 49. Note that Transocean has greater potential should a higher pump rate be required as it operates with a higher maximum surface pressure. Continuing with a 13 3/8” casing set at 5000m ECD will be higher than the fracture gradient if we operate with a pump rate of 2.0m^3/min. By decreasing it to 1.5m^3/min for both Maersk and Transocean we can prevent the ECD from crossing the fracture line as seen in Figure 25. Another way to solve it would be to increase the 13 3/8" casing length another 1000m while still operating at 2.0m^3/min pump rating. In terms of time spent and total cost, reducing pump rate would be a better solution compared to extending the casing. With all these considerations taken into account we end up with a theoretical maximum length of 12460m.

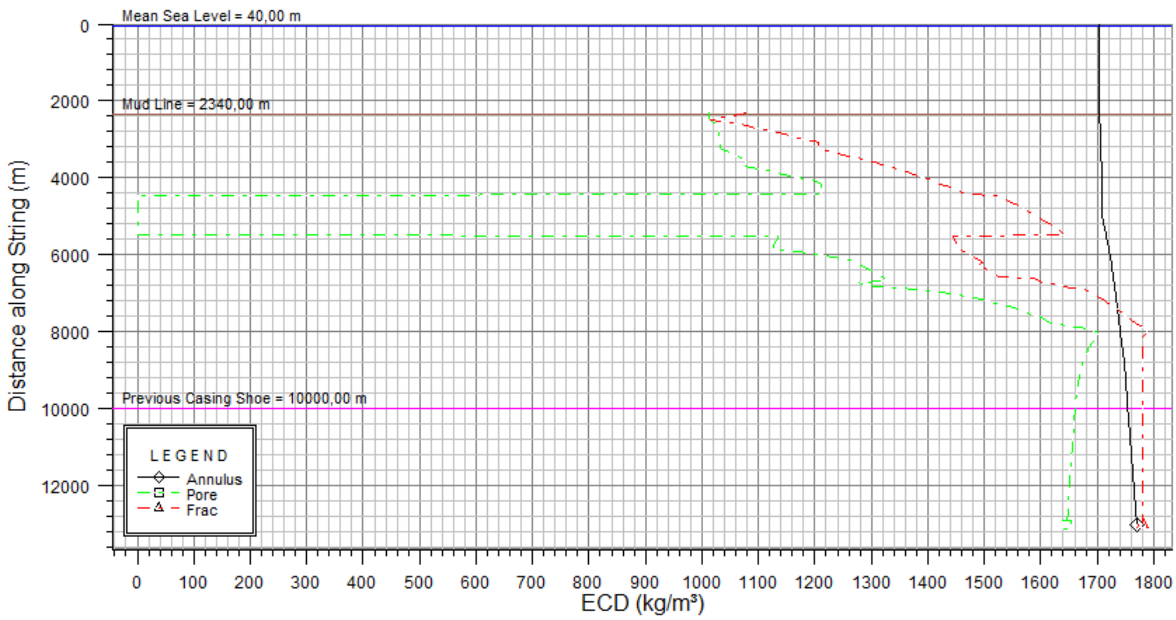

Figure 25: Maersk ECD vs. Depth at 13000m horizontal extension, pump rate at 1.5m^3/min (WELLPLAN).

The complete list of parameters for maximum horizontal extension can be found in Table 6. The difference between Maersk and Transocean torque and drag is due to the travelling assembly weight. Because Transocean's travelling weight assembly weighs 1147,4kN compared to Maersk which weighs 588,4kN, the hook load graph will shift the differential value to the right, which in this case is 559kN. Travelling assembly weight does not affect the final well length, it is only added in WELLPLAN to show that we get higher numbers with Transocean when reaching the exact same depth.

Study 2: Vertical Extension

Now we will try a different simulation where we alter exactly the same parameters and observe how they react in correspondence to each other, only this time the length extension is vertical. Well trajectory from the base case will be exactly the same in terms of inclination and horizontal length, the only difference will be that we move everything further down. In the wellpath editor for the original Willcox reservoir we add a desired amount of length above where the inclination starts. For the test simulation we add an additional 1000m to the TVD to see how the different parameters react. If all the torque, drag and hydraulic parameters are well within limits we will keep adding length until we reach the maximum theoretical length.

We start off by investigating the torque graph (Figure 50) where we find that the 5" drillpipe needs to be set below approximately 6047m to prevent buckling, when the 9 5/8" casing is set at 8000m. From the hook load chart we observed that buckling still occurs in the bottom end of the string (Figure 51), an issue that is solved by adjusting the casing setting depth to 9000m. The hole cleaning graph is roughly the same as in previous cases at 1.3132m^3/min for both Maersk and Transocean. The same goes for the pressure loss, neither one will have any problems operating at 2.0m^3/min pump rate, as we can see from Figure 52.

With the current pump rate of 2.0m^3/min the ECD is too high in the open hole interval (Figure 53). This can be fixed quickly by reducing the pump rate down to the minimum flow required for hole cleaning. However this will not be sufficient when we want to locate the theoretical maximum vertical extension, so we add an additional 13 3/8" casing down to 5000m to reduce ECD sufficiently. ECD is now well within pore-pressure and fracture gradient as seen in Figure 26.

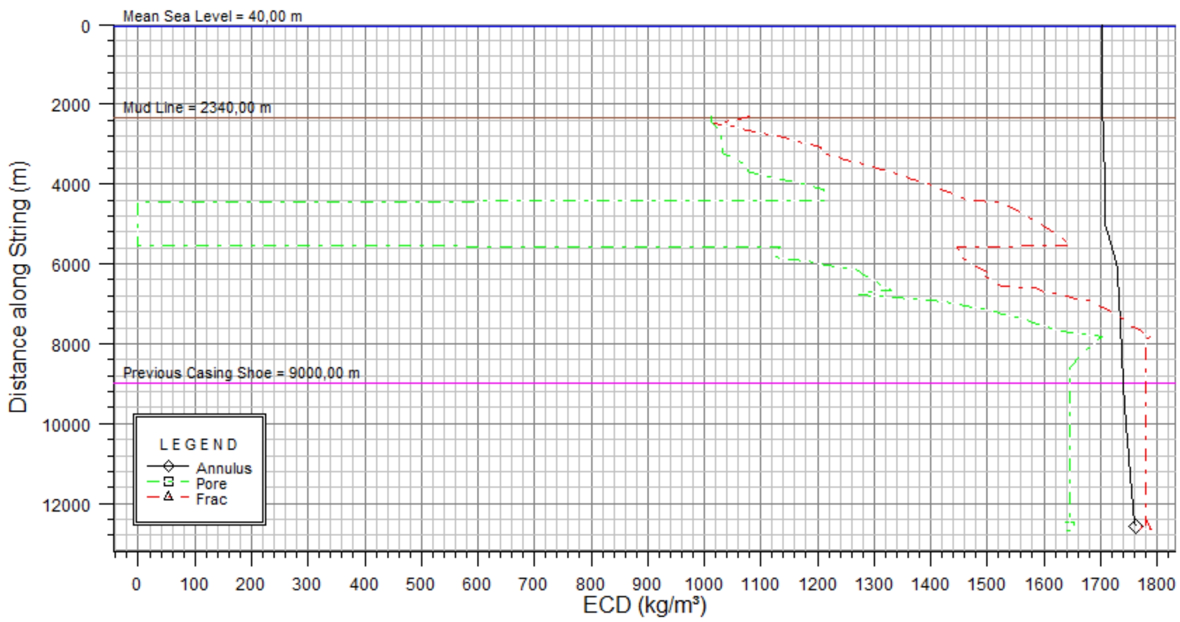

Figure 26: Transocean ECD vs. Depth at 1000m vertical extension, pump rate at 2.0m^3/min (WELLPLAN).

Considering the study of 1000m vertical extension we see the potential to proceed even deeper into the ground. However, there is no data on the pore and fracture gradients below 8544m TVD so we have to assume that they remain constant down to an eventual theoretical maximum depth. This is done by accessing the pore pressure and fracture gradient cases in WELLPLAN and adding an additional depth that we find deep enough for the study, and adding the data from previous depth to this one. The torque graph (Figure 54) tells us that the 5” drill pipe needs to be set deeper than 6885m to prevent buckling. When we look at the hook load graph we see something interesting; buckling due to tripping in is no longer the main issue as tripping out has crossed the maximum weight yield at the 9950m to 12200m interval (Figure 27). To solve this problem we need to set the 5” drillpipe deeper or shorten the 5 7/8” drillpipe interval, as the 6 5/8” drillpipe interval will adjust itself accordingly. By doing so we are able to manipulate the maximum weight yield line and shift it upwards and prevent tripping out from exceeding its limitation. In order to find the maximum reachable drilling depth we have to change the setting depths for the drillpipes until we find the optimal solution.

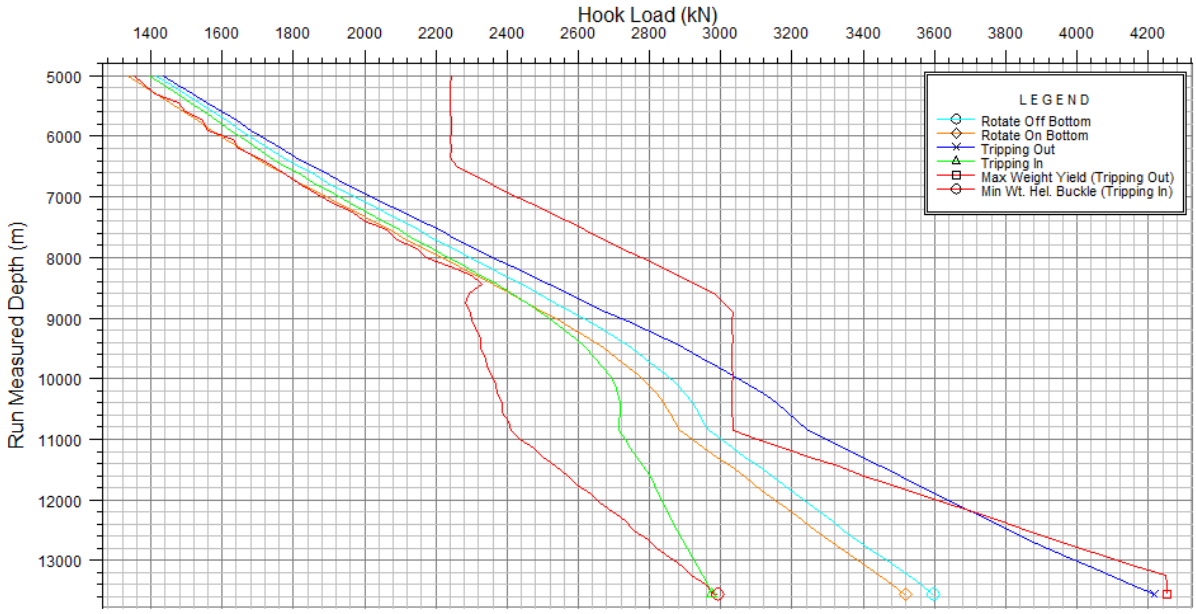

Figure 27: Hook load chart for Maersk, 2000m vertical extension (WELLPLAN).

After some trial and error it is clear that there is no possibility of reaching 13563.75m without either tripping in crossing the buckling line or tripping out crossing the yield line. The absolute maximum, without taking ECD into consideration, seems to be a depth of 13495m, where buckling will occur (Figure 55).

From the hole cleaning operational module for Maersk we find that a minimum flow rate of 1,3030m^3/min is required to clean the hole, the same rate applies for Transocean. Neither of the pump systems will have any trouble operating at this depth, but as we can see from Figure 28 Maersk is getting close to its depth limit having to keep the pump rate between 1,3030m^3/min and 1.741m^3/min. The Transocean pumps however are still well above its limit and capable of working with a pump rate above 2.0m^3/min (Figure 56).

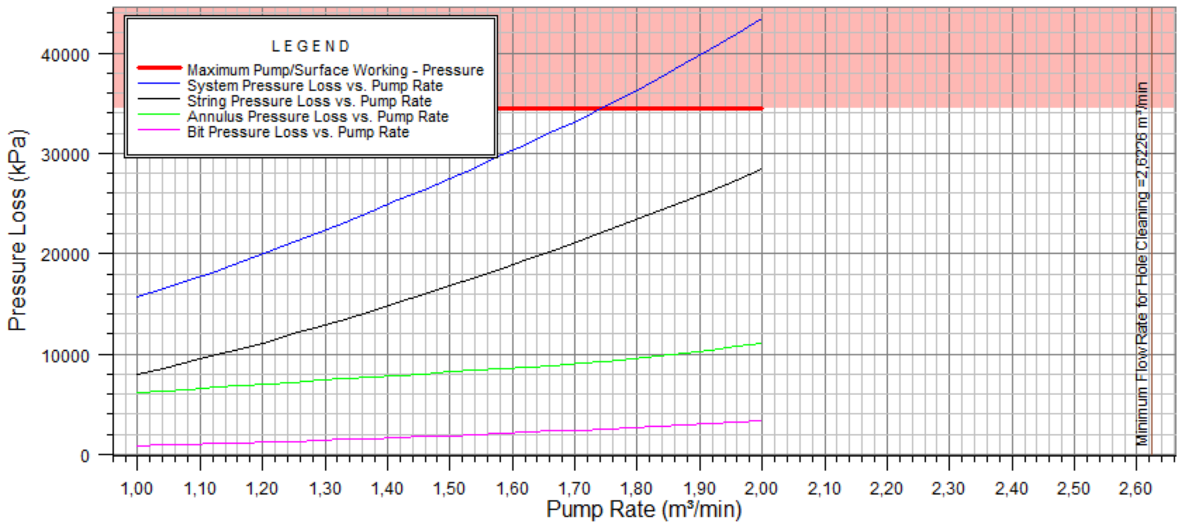

Figure 28: Pump rate range pressure loss for Maersk at 2000m vertical extension (WELLPLAN).

With the pump rate set to 1.74m^3/min in the pressure: pump rate fixed module, the ECD is getting too high at approximately 12000m depth for Maersk (Figure 57). This problem can be solved, as before, by adding a 13 3/8” casing down to 4000m (Figure 59) turning the 9 5/8” into a liner. Adding the extra casing will have a small, but significant, effect on the other parameters. For instance the tripping in line will exceed its limits at approximately 13300m (Figure 29), making this the new maximum depth, and the tripping out line is dangerously close to the yield line at some points and exceeding it at 13450m. The new minimum flow rate required to clean the hole as increased to 1.3121m^3/min, but the system pressure loss has decreased so that Maersk can now operate with a pump rate of 1.85m^3/min without exceeding maximum surface working pressure (Figure 58). Same as with the horizontal study a complete list of parameter values can be found in Table 6.

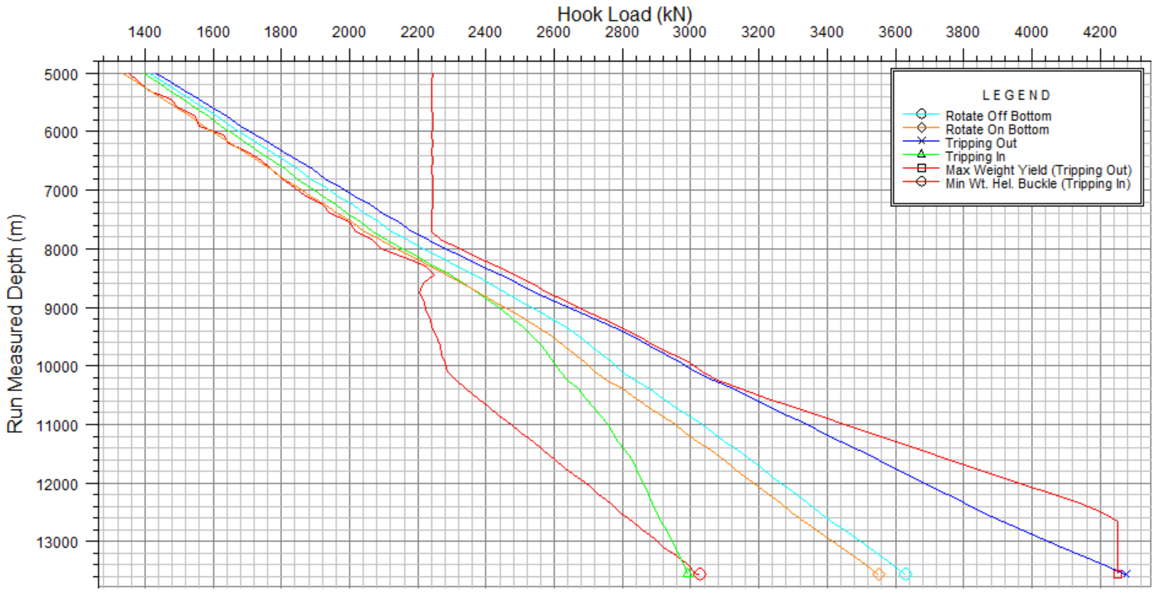

Figure 29: Hook load chart for Transocean, 2000m vertical extension (WELLPLAN).

Comments

From these two limitation studies we get surprisingly similar results, as both maximum theoretical depths are reached where trip in crosses the helical buckling line. Trip out being the second parameter to exceed its limits a bit further down the well trajectory; it is clear that hook loads are the main problem for these drilling operations. Hydraulics on the other hand was fairly easy to keep within limits, especially for Transocean with its immense pump system capacity. When looking at the weight the two rigs would need to pull (Table 7 and Table 8) we see that neither should have problems with maximum load considering derrick capacity. Loads will be a bit higher when taking friction and pulling through the bend into account, even so it would not be the limiting factor for this operation. As far as we can tell the only way to extend these two wells even further would be to have better drillpipes that can withstand higher values of torque and drag.

	Base case	Horizontal extension Maersk	Horizontal extension Transocean	Vertical extension Maersk	Vertical extension Transocean
TVD [m]	8441,38	8512,76	8512,76	10441,38	10441,38
Well length [m]	11563,75	13000	13000	13563,75	13563,75
Trip in max [kN]	2829,1	3191,6	3750,6	2991,7	3550,7
Trip out max [kN]	3984,3	4771,2	5330,2	4276,7	4835,7
Rotate on bottom max [kN]	3331,1	3900,6	4459,6	3550,5	4109,5
Rotate off bottom max [kN]	3411,1	3980,5	4539,6	3630,5	4189,5
Torque max [N-m]	42962,2	56803,8	56803,8	47380,5	47380,5
Min flow rate for clean hole [m3/min]	1,303	1,3122	1,3122	1,3123	1,3121
Surface working Pressure [kPa]	42542,77	21713,22	21713,22	30631,03	39769,41
Pump rate [m3/min]	2	1,5	1,5	1,74	2
ECD [m3/min]	1798	1771	1771	1753	1772
Frac ECD [m3/min]	1780	1781	1781	1781	1781
Max yield [kN]	4940,1	4840,9	5399,9	4252,5	4811,5
Min buckle [kN]	2835,2	3273,8	3832,8	3025,8	3584,8
Max well length [m]	11563,75	12460	12460	13340	13340
Max TVD [m]	8441,38	8494	8494	10425	10425

Table 6: Parameter values for horizontal and vertical extension, values from WELLPLAN.

Below weight calculations have been done for the horizontal and vertical extension. To simplify the calculations it has been assumed that total length for the horizontal extension is 13000m and 13563.75m for vertical extension, resulting in values a bit higher then what they should be at theoretical maximum depth. BHA calculations are based on Table 18.

Horizontal extension	Length [m]	Weight [kg/m]	Total weight [kg]	Total weight with buoyancy [kg]
13 3/8" casing	2664,2	101,1951	269604,1	211218,5
9 5/8" casing	5000	79,61677	398083,9	311874,6
During drilling				
6 5/8" dp	4636,134	61,65	285817,7	223920,8
5 7/8" dp	4200	41,82	175644	137606,4
5" dp	3900	33,66	131274	102845,2
BHA			20394,55	15977,9
Total weight drilling operation			613130,2	480350,4

Table 7: Weight calculations horizontal extension, values from WELLPLAN.

Vertical extension	Length [m]	Weight [kg/m]	Total weight [kg]	Total weight with buoyancy [kg]
13 3/8" casing	2664,2	101,1951	269604,1	211218,5
9 5/8" casing	3000	79,61677	238850,3	187124,8
During drilling				
6 5/8" dp	3399,884	61,65	209602,8	164211,1
5 7/8" dp	2400	41,82	100368	78632,25
5" dp	7500	33,66	252450	197779,3
BHA			20394,55	15977,9
Total weight drilling operation			582815,4	456600,6

Table 8: Weight calculations vertical extension, values from WELLPLAN.

Sensitivity Study

Effect of imperfections

Dogleg

A dogleg is defined as "a particularly crooked place in a wellbore where the trajectory of the wellbore in three-dimensional space changes rapidly" (Schlumberger). These are sometimes created on purpose, but the term is more commonly referring to a section of the hole that changes direction faster than anticipated or desired. For WELLPLAN we have to assume that the dogleg is 2-dimensional expressed in degrees per 30m. Some of the problems associated with doglegs is that the wellbore is no longer in the right location and the planned casing might have problems fitting through the curve. Different components of the BHA might become stuck in spots known as keyseats (Figure 30) due to abrasion by the drillstring in the curved area or if the BHA is stiff it might have problems moving through a dogleg drilled by a relatively limb BHA. The presence of dogleg(s) will also increase the overall friction which will make it harder to reach planned depth and increase the likelihood of a stuck pipe situation.

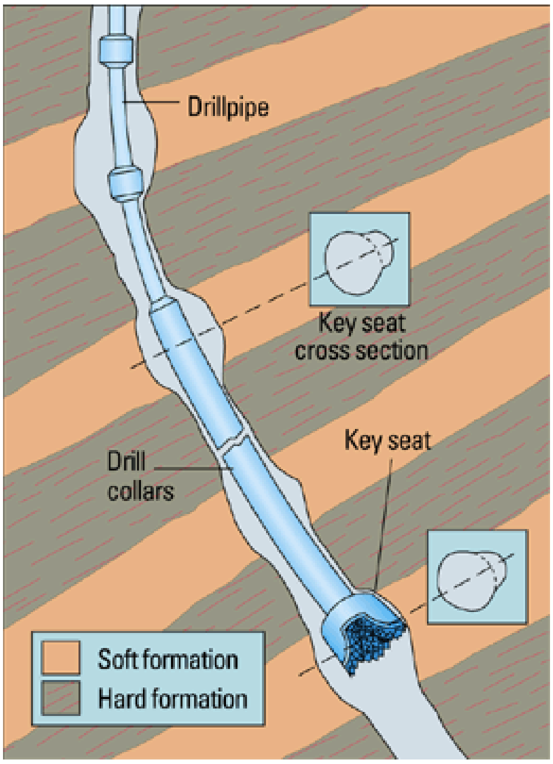

Figure 30: Diagram of keyseat (Schlumberger).

By creating a 2-dimensional dogleg in WELLPLAN we can observe how this will affect the parameters at the bottom of the well for the 12150m horizontal extension. Two different doglegs are made, DLS1 and DLS2 (Figure 31), where the second is more severe than the first. DLS2 might incline more degrees per 30m than what is possible to drill through, but it is used as it gives a good example of how a severe dogleg will affect planned endpoint data. Data for the two dogleg trajectories can be found in Appendix D along with the complete trajectory data for the 12150m horizontal extension.

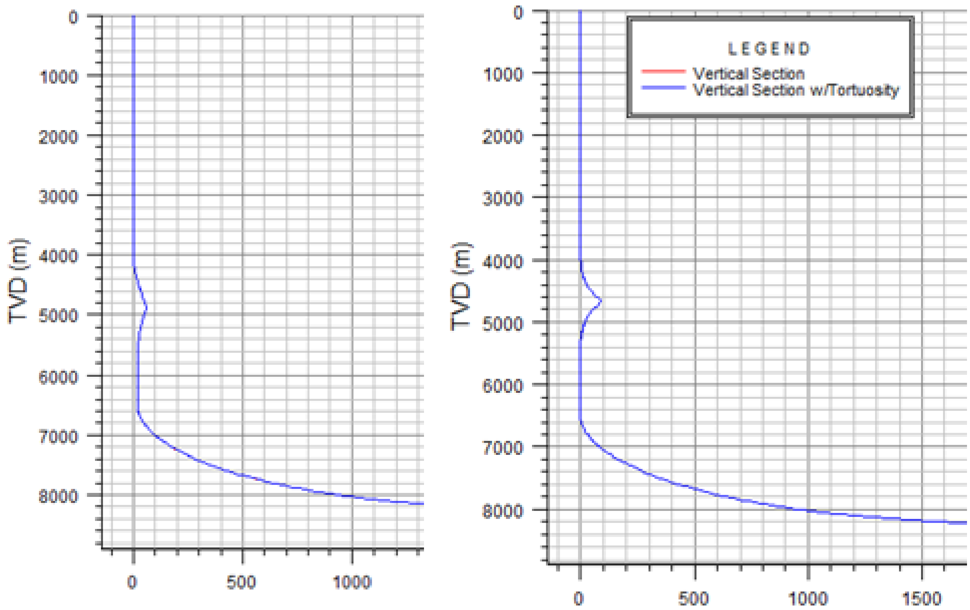

Figure 31: Well trajectory for DLS1 to the left and DLS2 to the right (WELLPLAN).

We observe that DLS1 has very little effect on the endpoint data from the hook load chart (Figure 61) but it has a fairly big effect on the torque values (Table 9), but it is still possible to reach this depth with the added dogleg. There are some changes on the helical buckling line that look like some sort of disturbance from the depth where the dogleg is starting, but tripping in is still well within its limit. For DLS2 (Figure 32) we get a completely different result with a huge increase in tripping out from the depth where the dogleg starts, as well as a reduction in the maximum weight yield line. This makes sense as it will be a lot harder to pull the pipe out when going through a bend, and it will deform more easily since extra stress is applied as a result of the dogleg. Even without the reduction of the maximum value of the yield line from approximately 5300kN to 4600kN the trip out line would cross it, making target depth unreachable. The endpoint data with and without DLS is found in Table 9.

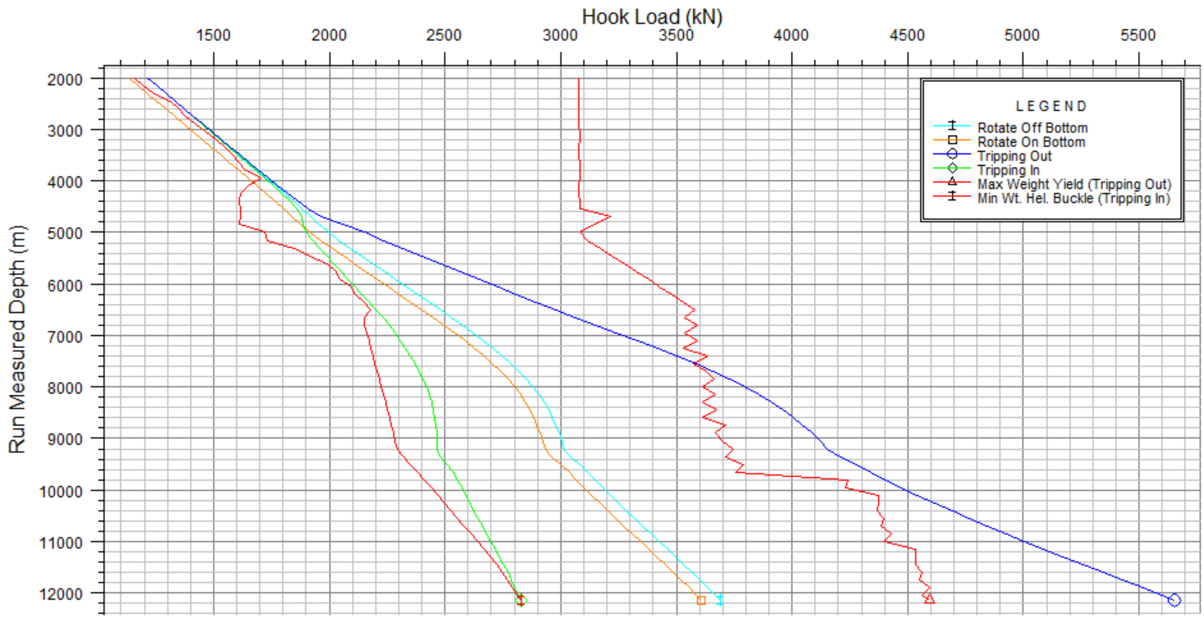

Figure 32: Hook load chart for 12150m horizontal extension, DLS2 (WELLPLAN)

Other than the minimum required flow rate for hole cleaning the hydraulics are barely affected by the adding of DLS. From Figure 33 we observe that the peak for the minimum flow rate occurs at the horizontal maximum of the dogleg.

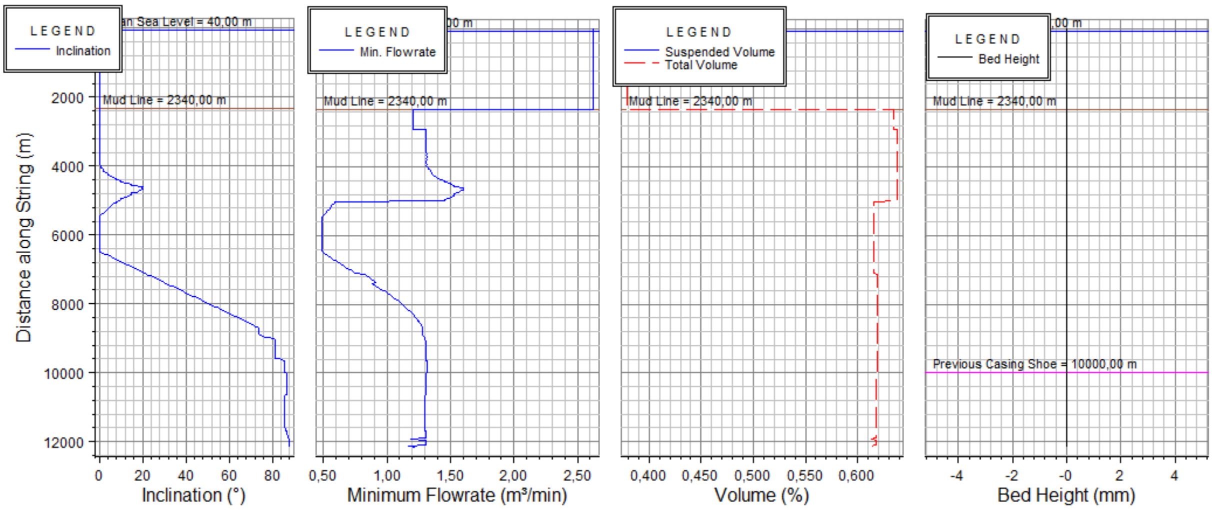

Figure 33: Hole cleaning operational for 12150m horizontal extension, DLS2 (WELLPLAN).

At bottom:	Without Dogleg	With DLS1	With DLS2
Trip in [kN]	3063,2	2975,0	2827,5
Trip out [kN]	4326,9	4702,8	5653,9
Rotate on bottom [kN]	3617,3	3615,7	3609,7
Rotate off bottom [kN]	3697,3	3695,7	3689,7
Torque max [Nm]	46139,7	62997,2	97177,1
ECD [m3/min]	1774	1774	1775
System pressure loss at 2.0 pump rate	33432,69	33432,69	33432,69
Min flow rate for hole cleaning [m3/min]	1,3123	1,4012	1,6037

Table 9: Parameter values at the bottom of the well for 12150m horizontal extension, data from WELLPLAN.

Result Matrix

The ideal/normal friction factor when drilling is 0.18 for cased hole and 0.24 for open hole (Sangesland, Xiaojun He, & Islam, 2011). Based on data from similar cases, I have decided to use 0.33 for cased hole and 0.38 for open hole in agreement with Alasdair. In Table 10 and Table 11 we observe how big of an impact a decrease in the two friction factors will have on torque and drag (hook load). The values are obtained by altering the friction factors in the base case. Since 0.33 and 0.38 represents worst case scenario for cased hole and open hole, respectively, it is decided to only show how torque and drag reacts when these values are reduced. Percentage reduction with respect to the base case values are shown in Appendix C. In WELLPLAN the drag is defined as the amount of workstring weight being supported by the formation due to friction and contact forces. This means that during trip in the drag will lower the measured weight at the surface and increase the measured weight during trip out. In the tables presented below we can observe how different drilling parameters affect torque, drag and ECD.

Friction factor	Trip out max [kN]	Trip in max [kN]	Drag out max [kN]	Drag in max [kN]
OH=0.38 CH=0.33	3984,3	2829,1	573,2	-582
OH=0.33 CH=0.33	3923,1	2896,3	512	-514,8
OH=0.38 CH=0.25	3910,7	2900,5	499,6	-510,6
OH=0.30 CH=0.25	3824,5	2993,8	413,4	-417,3
OH=0.24 CH=0.25	3766,7	3058,8	355,6	-352,3
OH=0.30 CH=0.18	3771,2	3041,8	360,1	-369,3
OH=0.24 CH=0.18	3717	3102,3	305,9	-308,8

Table 10: How friction factor affects tripping and drag, values from WELLPLAN.

From Table 10 we observe that as the friction factor is decreasing the value of trip out is decreasing and trip in is increasing, this is as expected as a lower friction factor should make the tripping operation easier. As a result tripping in and tripping out will shift further away from minimum weight helical buckling and maximum weight yield respectively. Additionally it is observed that the change in drag out equals the change in trip out when we alter the friction factor, showing that the two is dependant of each other as mentioned in the WELLPLAN-definition. The same goes for trip in and drag in.

Friction factor	Rotate on bottom [N-m]	Rotate off bottom [N-m]
OH=0.38 CH=0.33	42962,2	37553,3
OH=0.33 CH=0.33	39792,7	34431,3
OH=0.38 CH=0.25	39598,8	34201,5
OH=0.30 CH=0.25	34527,6	29206,3
OH=0.24 CH=0.25	30724,2	25459,9
OH=0.30 CH=0.18	31584,7	26273,5
OH=0.24 CH=0.18	27781,2	22527,1

Table 11: How friction factor affects torque, values from WELLPLAN.

Table 11 shows similar results to those we got for drag, with a significant reduction in torque from worst case scenario to "ideal" friction factors.

Mud density [kg/m3]	Trip out max [kN]	Trip in max [kN]	Drag out max [kN]	Drag in max [kN]
2	3824,2	2721,1	547,0	-556,1
1,8	3930,9	2793,1	564,5	-573,4
1,7	3984,3	2829,1	573,2	-582,0
1,6	4037,7	2865,1	582,0	-590,7
1,5	4091,1	2901,0	590,8	-599,3

Table 12: How mud density affects tripping and drag, values from WELLPLAN.

The light grey area in Table 12 marks the mud density used in the simulations. As expected an increase in mud density will decrease both trip in and out, the opposite happening when mud density decreases. This comes as a direct result of drag being dependant of the buoyancy factor.

Mud density [kg/m3]	Rotate on bottom max [kN]	Rotate off bottom max [kN]	ECD [kg/m3]	System pressure loss At 2.0pump rate [kPa]
2	3197,2	3277,2	2102	47190,43
1,8	3286,5	3366,5	1900	44145,17
1,7	3331,1	3411,1	1798	42542,76
1,6	3375,7	3455,7	1696	40836,17
1,5	3420,4	3500,4	1596	39107,51

Table 13: How mud density affects rotate on/off bottom, ECD and system pressure loss, values from WELLPLAN.

Table 13 also has the mud weight used in the simulations marked in light grey. From the table we observe that an increase in mud weight will have a positive effect on rotating on and off bottom, which is as expected considering they are both dependant on buoyancy factor. ECD increases and decreases by a fair amount when we alter the mud weight, with a mud weight of 2.0 kg/m^3 the ECD is well above the fracture gradient, which has a max value of 1780kg/m^3 in the base case. The system pressure loss is higher with a heavier mud, this is as expected as a heavier mud will require a higher pressure from the pump system. In Appendix C there are tables showing the percentage increase/decrease in the different values compared to the parameters used in the base case.

Mud density [kg/m3]	Rotate on bottom [N-m]	Rotate off bottom [N-m]
2	41285,0	35858,2
1,8	42401,7	36987,1
1,7	42962,2	37553,3
1,6	43524,0	38120,6
1,5	44087,0	38688,8

Table 14: How mud density affects torque, values from WELLPLAN

From Table 14 we get similar results for torque as we did for drag due to the dependency on buoyancy.

	12150m horizontal extension	13000m horizontal extension
Length [m]	586,25	1436,25
Drag in [kN]	52,1	208,5
Drag out [kN]	56,4	218,3
Drag max calc [kN]	105,5	258,6
Drag min calc [kN]	57,6	141,2
Rotate on bottom [N-m]	3177,5	13841,6
Rotate off bottom [N-m]	3245,8	13794
Torque max calc [N-m]	4273,8	10470,3
Torque min calc [N-m]	3658,2	8962,2

Table 15: Torque and drag increase based on simple calculations.

Table 15 compares torque and drag values read from WELLPLAN with results from the simplified calculations. In theory the WELLPLAN values should be between the minimum and maximum calculated value, however for this simplification there are many factors we have chosen to ignore. The friction factor we chose at constant value of 0.38 will vary between 0.33 and 0.38 as we have longer casing sections as we extend the well. This should reduce our calculations by a fair amount and give a more accurate result. Some of the drillpipe sections are shorter for the extension than they were in the base case, which would affect our calculations. Additionally there is a small inclination which we have neglected. We also observe that the WELLPLAN values increase more than our calculated values going from the 12150m to 13000m horizontal extension. This is most likely a direct result of our calculations ignoring the effect the bend will have on the bottomhole values. An interesting observation is that the bend seem to have a greater impact on torque than drag.

Discussion

When drilling in deep waters there are many careful considerations that need to be taken, as accidents in the open sea can be a serious threat to the global environment. The deeper we go the less experience we have, and with directional drilling on top of that the industry is still taking its first steps. Many of the methods presented in the literature study, DGD in particular, could help increase production and development, but most are not yet ready for commercial use.

One common problem regarding deepwater is rig specifications and costs associated with them. Deeper water requires more specialized, thus more expensive, equipment, which means newer generation rigs with higher operational costs will be needed. This means that a field that normally would be economically feasible, had it been located in shallow water, has to be put on hold due to too high operational costs. Previously mentioned slender well technology, which reduces amount of casing and therefore allowing older generation rigs to be used, will make some of these reservoirs economically feasible again. This should only be proposed as a solution after carefully considering if all environmental risks can be avoided, as slender wells seem weaker and more susceptible to formation damage.

Transocean Discoverer Americas and Maersk Developer belong to the newer generation of rigs, both having immense operational capacities. When comparing their torque limit, 137200 Nm and 128800 Nm respectively, to the maximum reached during horizontal extension (56804 Nm), it is clear that the rigs would have no problems doing these operations. The same goes for pump capacity, which only is limited by eventual ECD. The real limiting factor for torque and drag seems to be the drillpipes. The ones used in this thesis is a few years old, so there might be a better option available on the market, but I highly doubt it will surpass the maximum rig capacity. Many companies, Petrobras™ among them, are currently working with nano technology and other methods in order to strengthen the drillpipes. There are no actual data on how this might affect the drilling operations, and it was only mentioned as a future goal 20 years ahead in time on the presentation I attended. Should they be successful, it is quite possible we can drill even deeper and with less complications, and rig specifications might become the limiting factor.

ECD was an issue in all of the cases we have investigated in this thesis when the 9 5/8" casing was used in the entire casing section. And when pump rate reduction alone was not enough we had to turn the 9 5/8" casing into a liner and use a 13 3/8" casing to a certain depth to reduce total ECD. This is something that might not be possible without using DGD technology, as it most likely would be required to set more casings if we use conventional drilling. With DGD we are able to manipulate the pressure window, and as a result we can set fewer casing and set the bigger radius casings deeper. An additional benefit with DGD is the use of heavier mud types which can reduce formation damage and help with lost circulation. Increased radius means less velocity and less ECD, which means that DGD will be a very important tool to compensate for challenges related to ECD.

The narrow window between pore pressure and fracture gradient is repeatedly mentioned in most literature about deepwater drilling as the main area of concern. And if we do not have sufficient information about this and other wellbore parameters it could be considered a limiting factor. The previously mentioned industry drilling envelope, if used to its full potential, could be of great help in these situations. As we can see from Figure 2 our wells are all outside the boundary of currently drilled wells. I have chosen to include the well when normalized for water (green) and when it is not (blue), as we do not know if which one best represents final wellbore data. The arrows included are pointing towards the horizontal and vertical extension. This means that we have no accurate data to base our simulations on and we have to assume that this wellbore will act similar to the closest wellbore we have available data from. If we were able to obtain data from some of the wells Shell has drilled in GoM, Princess for instance, we would be able to make more realistic simulations.

Alasdair Fleming has designed the base case as if it is a worst case scenario, which means that even though the data presented in this thesis might not give a very accurate picture of the actual wellbore we can still observe typical trends and get a good interpretation of limiting factors. Friction factor might be the parameter that is furthest away from an actual wellbore, with nearly double values of what is commonly used. With a lower friction factor we would have been able to extend the well even further, and it might have been ECD that turned out to be the limiting factor instead of the drillpipes. For the vertical extension we surpassed the TVD end point for pore pressure and fracture gradient, and we had to assume that these values would remain constant throughout the entire extension. This has some effect on the final result as it is highly unlikely that we will have constant pressure over a 2000m depth interval.

From the sensitivity study we see how big of an impact friction factor and mud weight actually has on torque and drag, supporting my theory that in actual wellbore conditions we would have been able to extend the well even further. It is also worth noticing that even a small dogleg severity will greatly impact wellbore parameters with torque values going through the roof. In order to be able to avoid or handle these uncertainties I once again have to point out the importance of having initial knowledge of the well trajectory and information from the wellbore.

WELLPLAN^{TM} has its limitations and I have limited knowledge on how to use it, so I am assuming that there are quite a few factors during deep water operations that have not been mentioned in this thesis. That being said, I do believe the presented data is covering the main areas of interest for these types of operations and gives a good interpretation on where future focus should be put.

Conclusion

Based on the simulations done in WELLPLAN™ we have learned that it is possible to extend the Willcox well trajectory both horizontally and vertically. Considering friction factor and mud weight used it is safe to assume that with actual wellbore data we would have been able to go even further than this thesis has shown. When comparing equipment requirements with the rig specifications of Transocean Discoverer Americas and Maersk Developer we observe a lot of unused potential, with both rigs being far from their maximum limits. Had the simulations given other results, it is worth mentioning that Transocean have the greater potential of the two.

Case study showed that the limiting factor for this operation would be the strength of the drillpipes in terms of torque and drag. When WELLPLAN™ gave the warning for buckling we had barely passed half of the maximum torque capacity for both rigs. ECD could easily be reduced by using a larger diameter casing than the base case, turning the 9 5/8" casing into a liner. However, this operation will require the use of MPD or DGD technology to manipulate the pressure profile. If neither technology is available ECD would be the limiting factor for this case study, meaning the operations could not have been completed using conventional drilling.

In order to do more accurate simulations in the future the main task would be to gather data from similar projects. With more knowledge beforehand we will decrease the chances of dogleg severities and running into other imperfections that might affect the trajectory. Additionally we will be able to evaluate if the reservoir is suitable for slender well technology, DGD or other drilling methods. Using the industry drilling envelope is a great tool to located similar wells, and will play an important part in obtaining useful data for future simulations.

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Nomenclature

BHA	-	Bottom Hole Assembly
POOH	-	Pulling Out of Hole
GoM	-	Gulf of Mexico
ECD	-	Equivalent Circulating Density
ESD	-	Equivalent Static Density
BBO	-	Billion Barrels of Oil
md	-	millidarcy
TVD	-	True Vertical Depth
DGD	-	Dual Gradient Drilling
MPD	-	Managed Pressure Drilling
IADC	-	International Association of Drilling Contractors
CBHP	-	Constant Bottom Hole Pressure
PMCD	-	Pressurized Mud-Cap Drilling
UBD	-	Underbalanced Drilling
UBO	-	Underbalanced Drilling Operations
DLS	-	Dogleg Severity
OH	-	Open Hole
CH	-	Cased Hole
TLP	-	Tension-Leg Platform
FPSO	-	Floating Production, Storage, and Offloading system
BHCT	-	Bottomhole Circulating Temperature
BOP	-	Blowout Preventer
CAPM	-	Continuous Annular Pressure Management
SMP	-	Subsea Mudlift Pumping

LRRS	-	Low Riser Return System
CMP	-	Controlled Mud Pressure
RMR	-	Riserless Mud Recovery
SPM	-	Subsea Pump Module
SMO	-	Suction Control Module

Appendix A. System Specifications and WELLPLAN Data

Discharge flow max	3,348 l/min
Operating pressure max	7,500 psi
Input power requirement	2,200 hp
Rated pump speed	110 min^{-1}
Max. fluid line bore	7 ½ inch
Stroke	14 inch
Valve size	API 8
Suction connection	10 inch -150 lb. ANSI B 16.5 WN flange
Discharge connection	4 1/16 inch, 10,000 psi API 8 A RTJ

Table 16: Technical data for the Wirth TPK pumps used on Maersk Developer (Wirth).

Max pump rate	3,915 l/min
Max discharge pressure	7,500 psi
Input power	2,540 hp
Max pump speed	212 SPM
Liner size	4 ½ inch
Stroke length	11.8 inch
Number of pistons	6
Valve size	P7

Table 17: Technical data for the Hex II pump used on Transocean Discoverer Americas (National Oilwell Varco).

Section type	Length (m)	OD (mm)	ID (mm)	Weight (kg/m)	Description
Heavy Weight	27.000	127.00	76.20	74.62	5.0in, 50.14ppf, 1340 MOD, 5 ½ FH
Jar	9.449	165.10	69.85	136.60	Hydraulic Jar Dailey Hyd., 6 ½ in
Heavy Weight	192.024	127.00	76.20	74.62	Non-Mag H. Weight, 1340MOD, 5 ½ FH
Stabilizer	9.449	171.45	71.37	134.41	FPWD Tool
MWD	9.499	171.45	71.37	134.41	MWD Pulser
Stabilizer	7.681	171.45	50.80	159.44	LWD GR/RES/DENS/NEUT
Heavy Weight	2.500	127.00	76.20	73.13	RSS Flex
Stabilizer	1.524	152.40	71.45	111.73	RSS Top Stab
Drill Collar	3.000	171.45	76.20	143.92	RSS BODY
Stabilizer	1.500	152.40	71.45	111.73	RSS Steering Head
Bit	0.024	215.90		212.81	Polycrystalline Diamond Bit, 5x11, 0.464in^2

Table 18: Data for the default BHA (WELLPLAN).

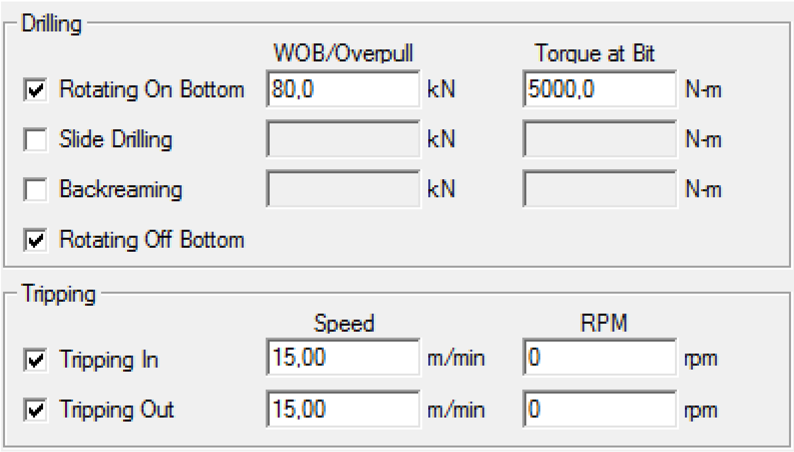

Figure 34: Run parameters for Torque and Drag charts (WELLPLAN)

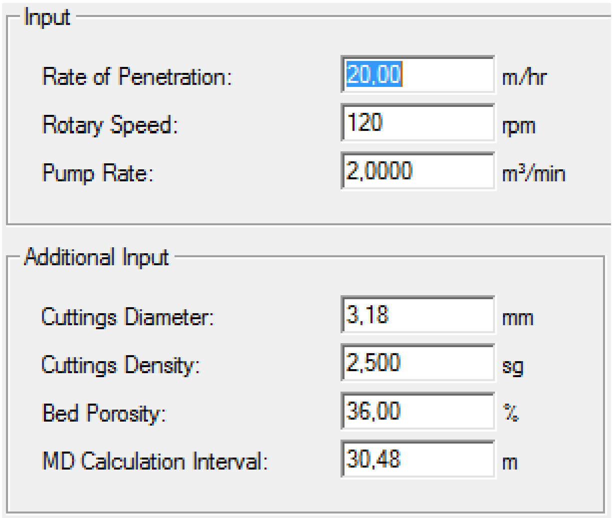

Figure 35: Transport analysis data (WELLPLAN)

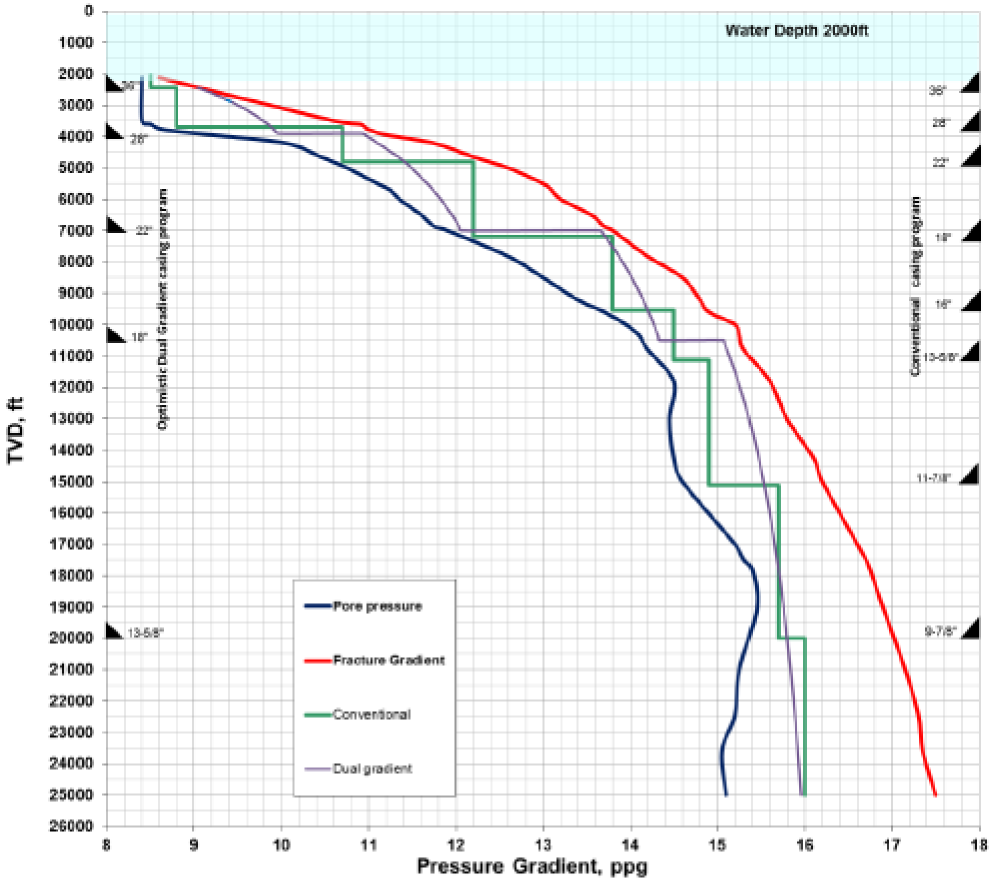

Figure 36: How DGD can reduce number of casing, compared to conventional drilling (Godhavn, 2012).

Appendix B. WELLPLAN Figures

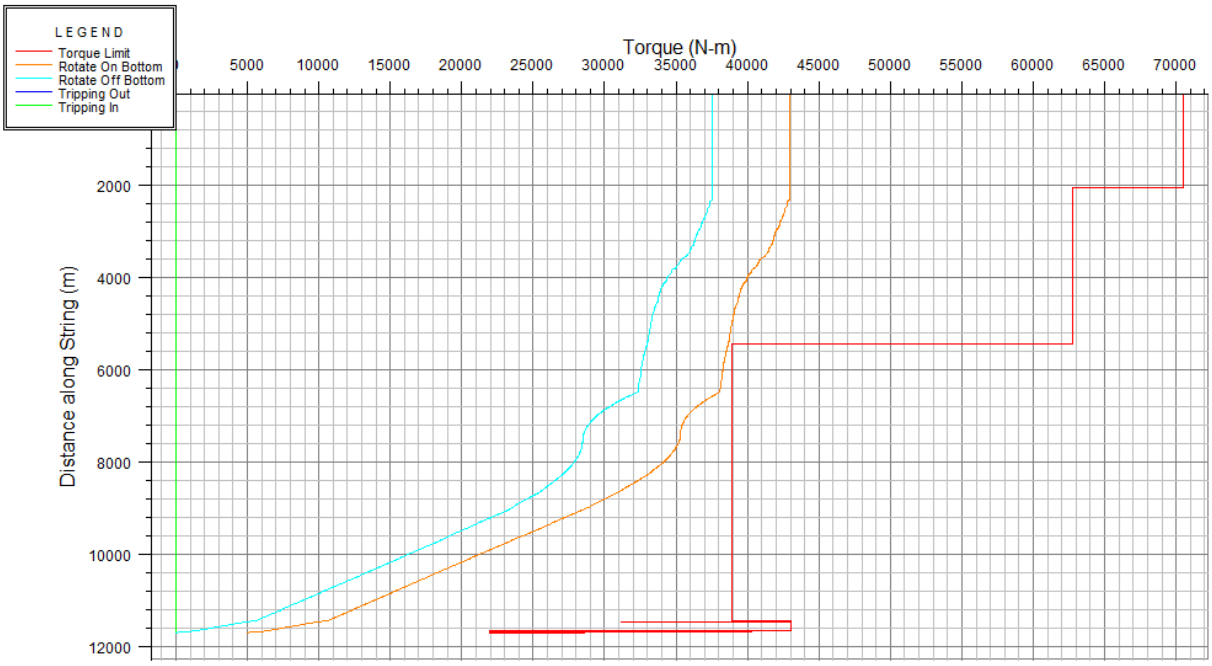

Figure 37: Torque graph, base case

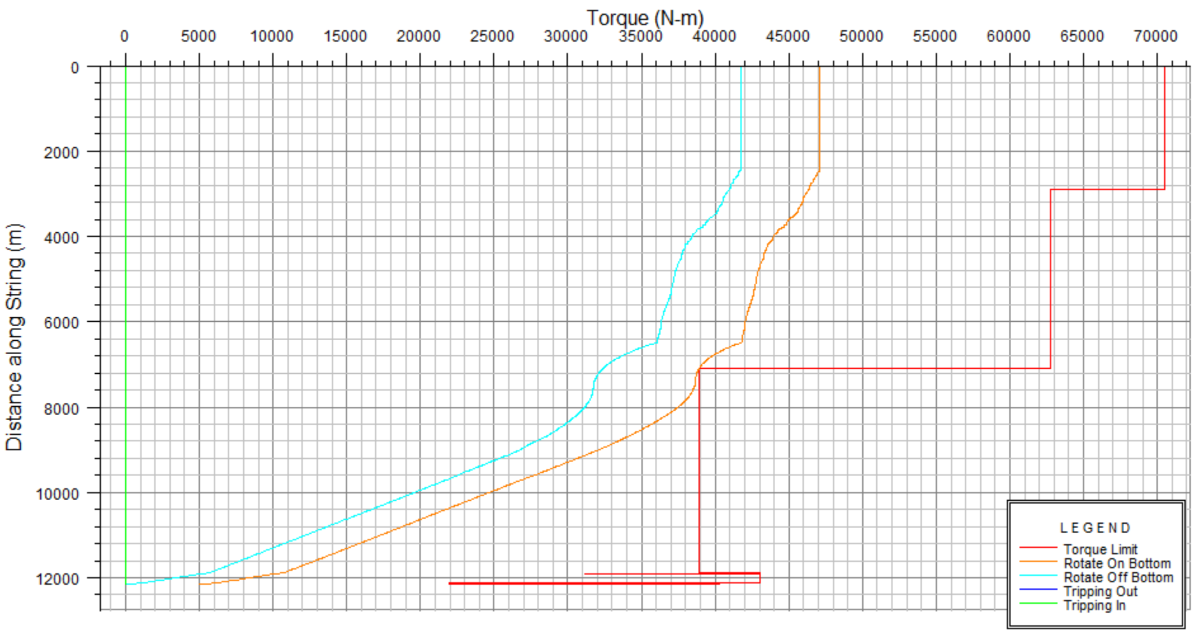

Figure 38: Torque chart for 12150m horizontal extension, 5” pipe set at 7106m. (WELLPLAN)

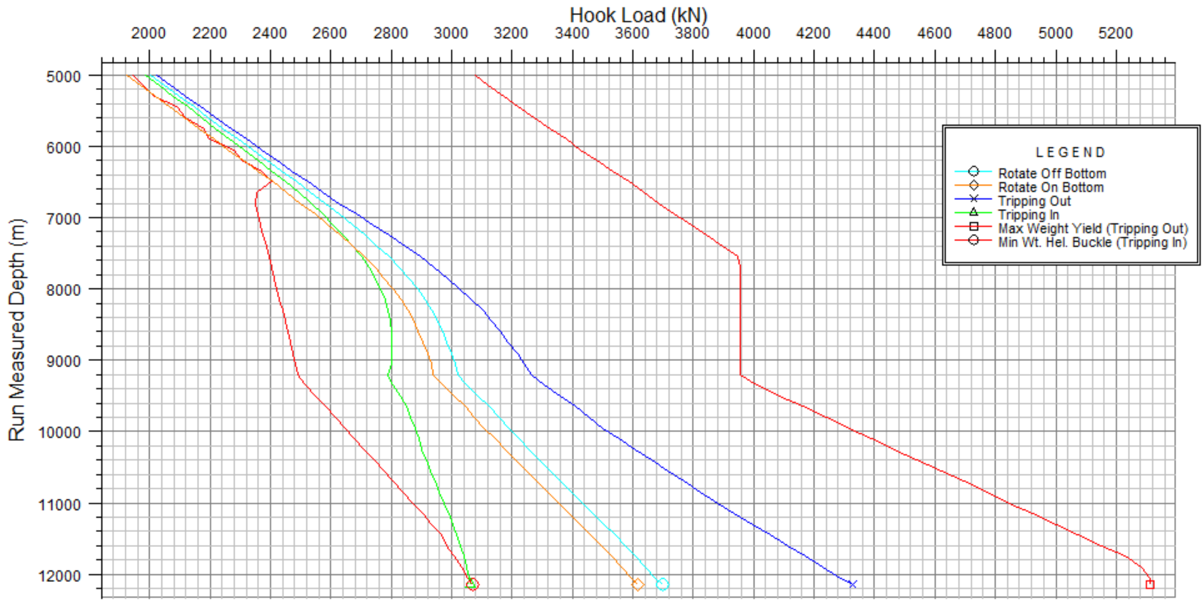

Figure 39: Hook load chart for Maersk at 12150m horizontal extension, casing depth increased to 10000m (WELLPLAN).

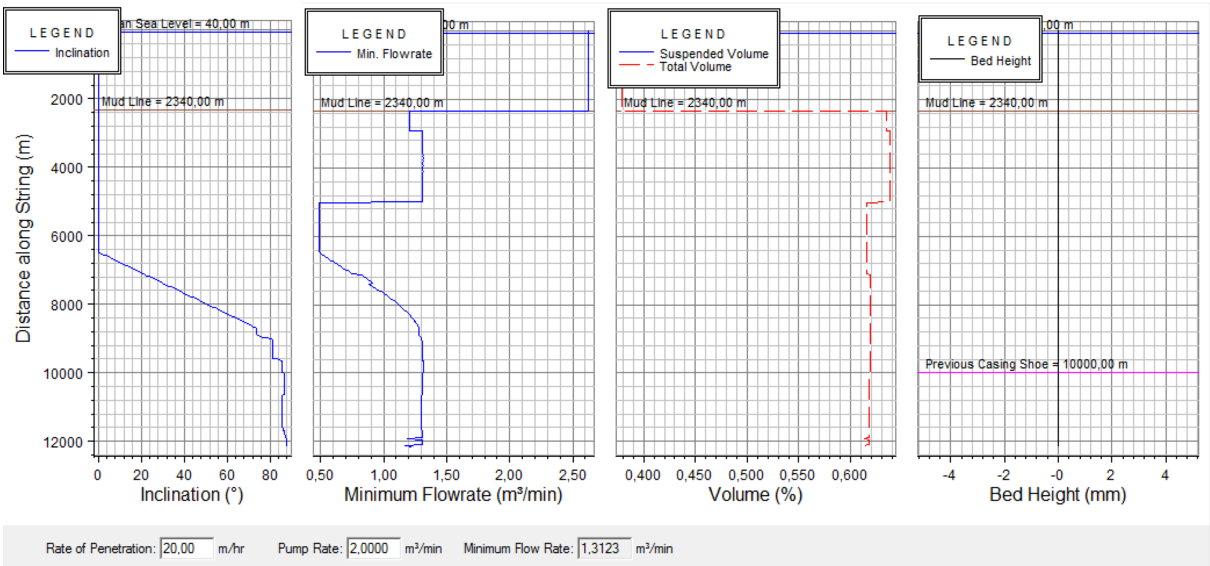

Figure 40: Hole cleaning operational for Transocean at 12150m horizontal extension (WELLPLAN)

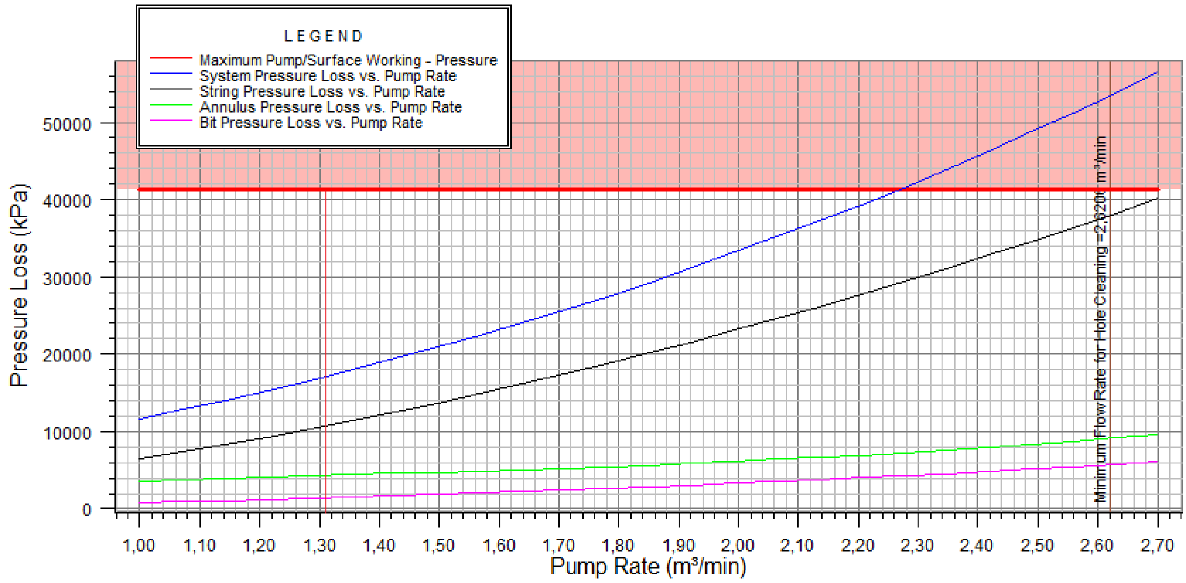

Figure 41: Pump rate range pressure loss for Maersk at 12150m horizontal extension. Red vertical line represents actual flow rate required for hole cleaning. (WELLPLAN)

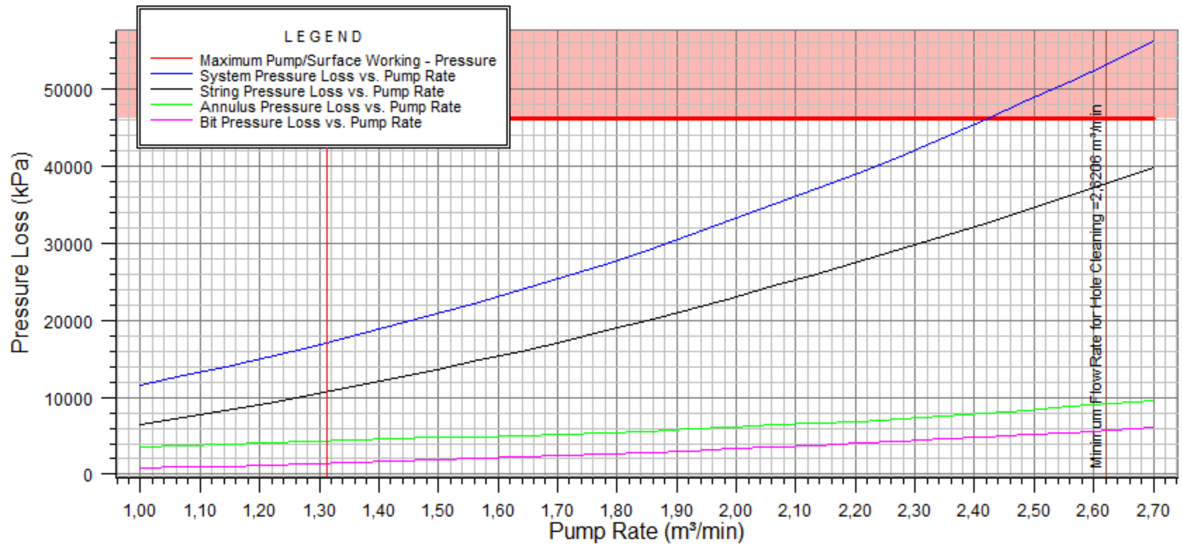

Figure 42: Pump rate range pressure loss for Transocean at 12150m horizontal extension. Red vertical line represents actual flow rate required for hole cleaning. (WELLPLAN)

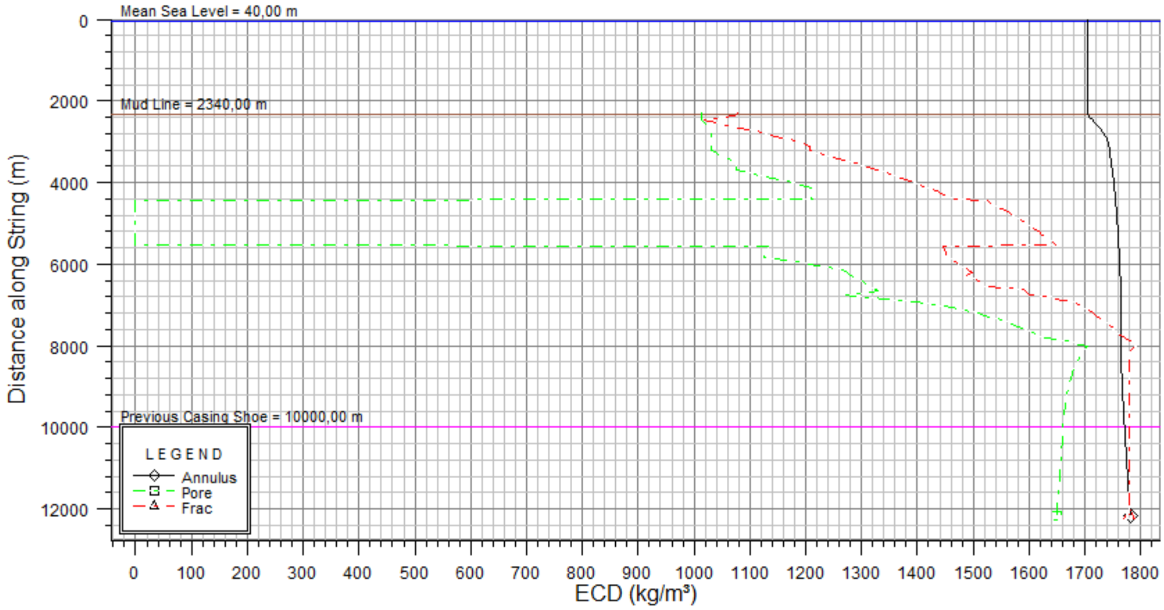

Figure 43: Transocean ECD vs. Depth at 12150m horizontal extension, pump rate at 1.3122m^3/min. (WELLPLAN)

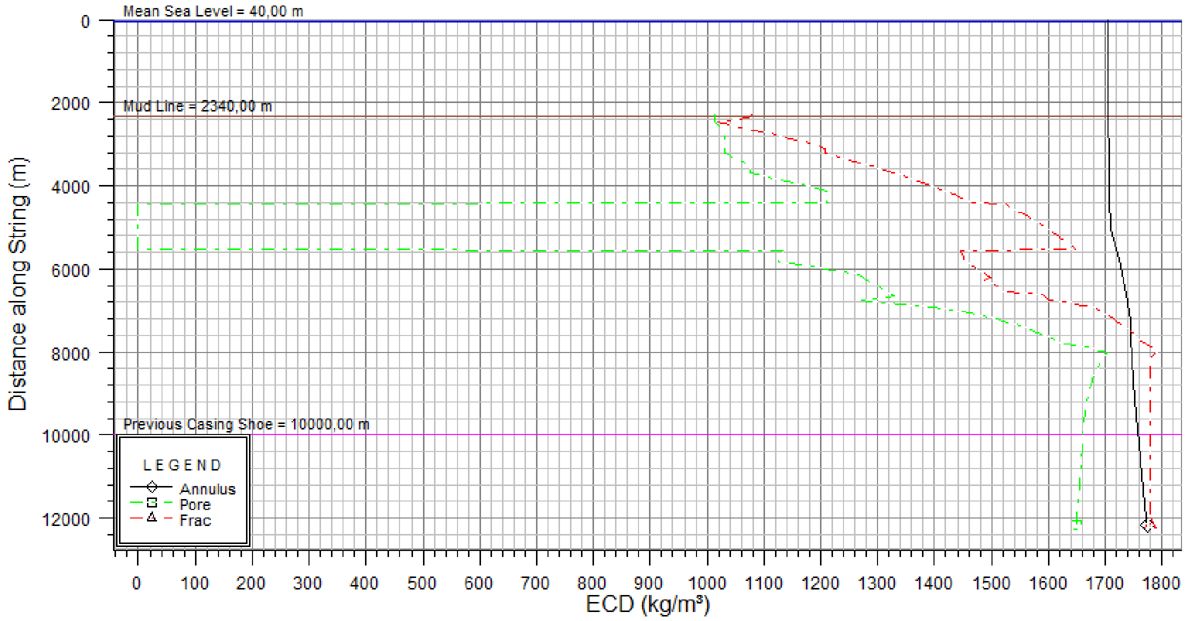

Figure 44: Maersk ECD vs. Depth at 12150m horizontal extension, pump rate at 2.0m^3/min (WELLPLAN)

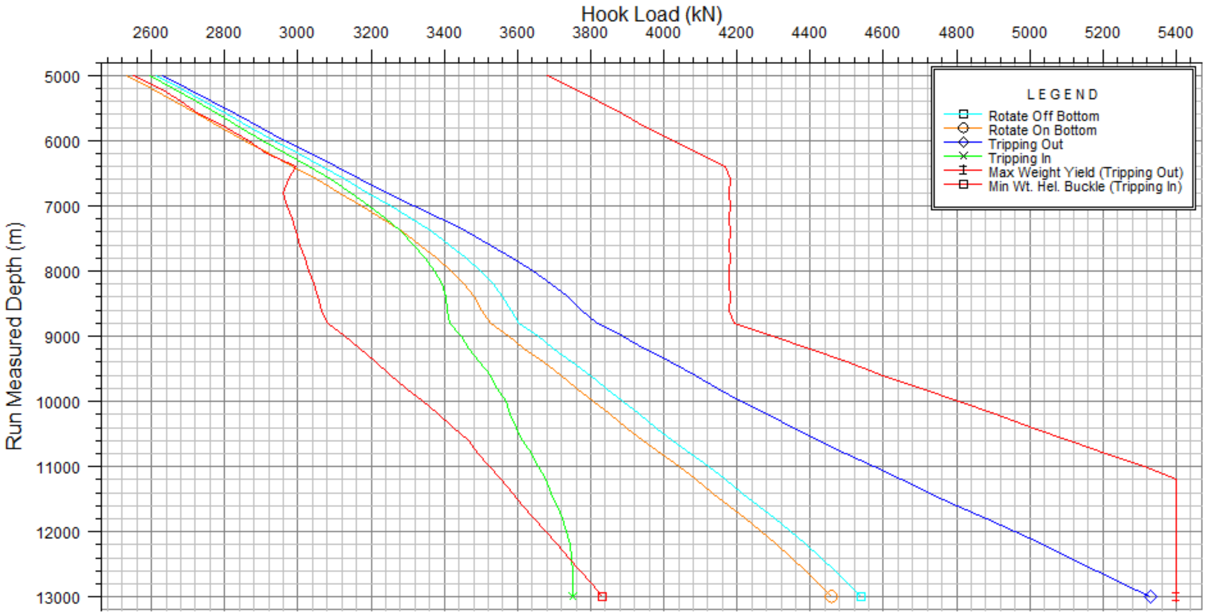

Figure 45: Hook load chart at 13000m horizontal extension, casing to 10000m (WELLPLAN)

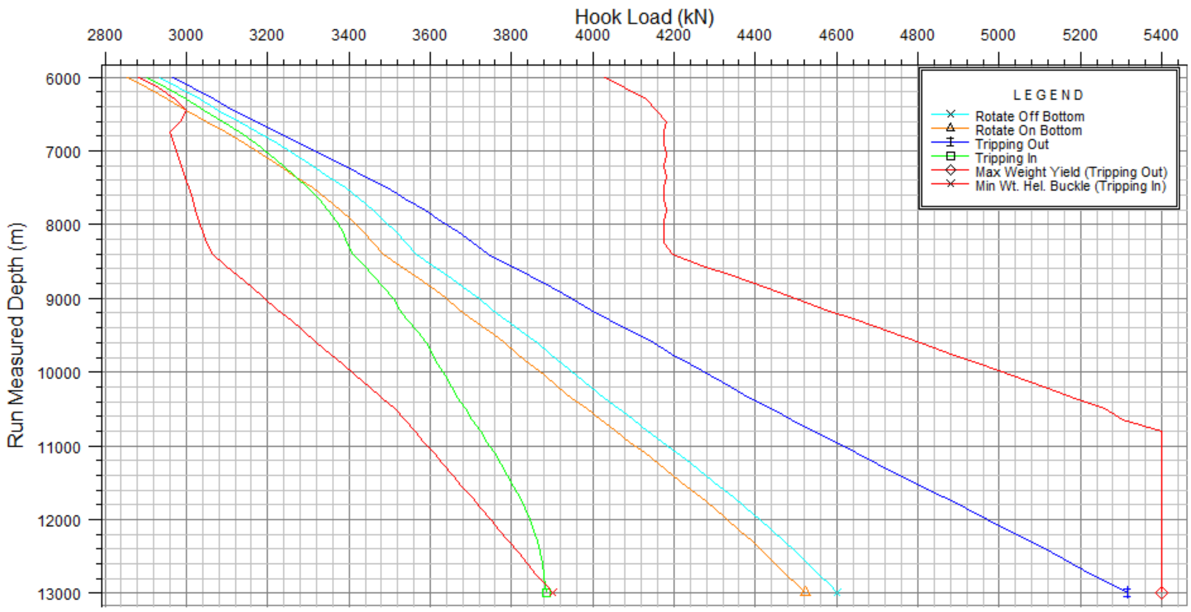

Figure 46: Hook load chart at 13000m horizontal extension, casing to 13000m (WELLPLAN)

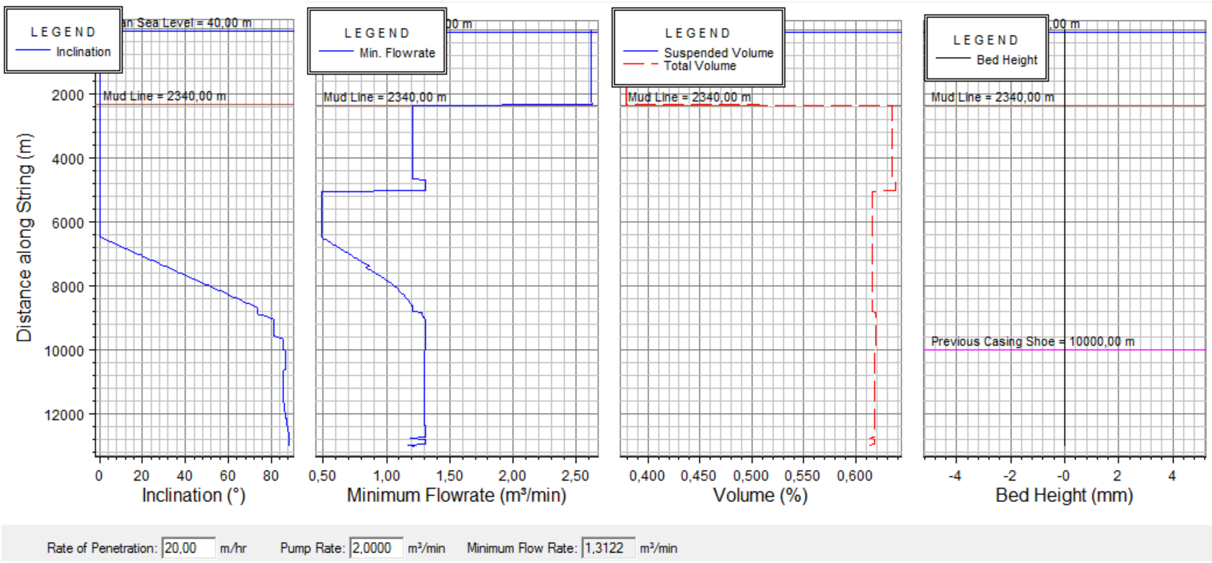

Figure 47: Hole cleaning operational for Transocean at 13000m horizontal extension (WELLPLAN).

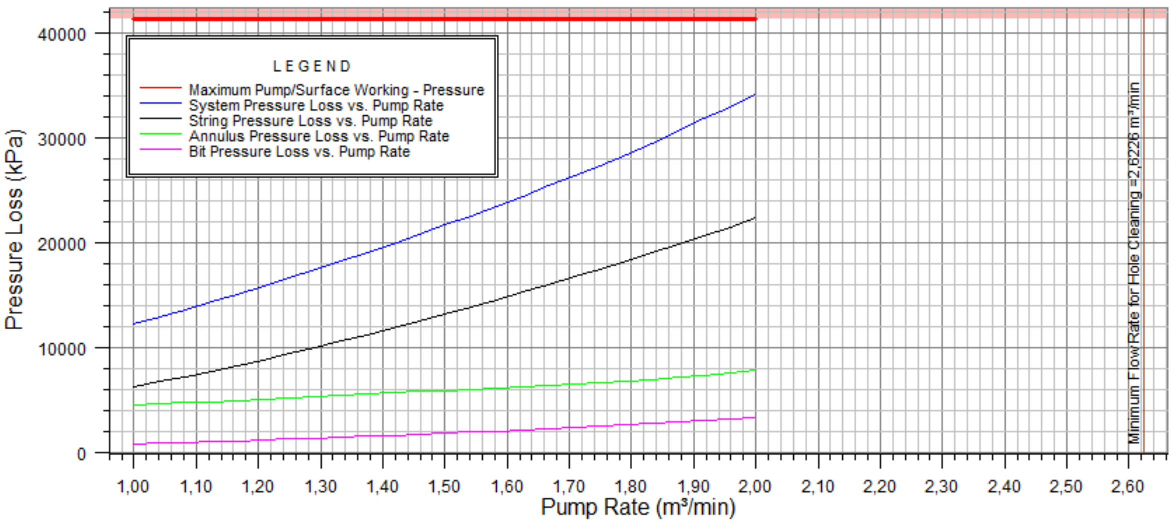

Figure 48: Pump rate range pressure loss for Maersk at 13000m horizontal extension (WELLPLAN).

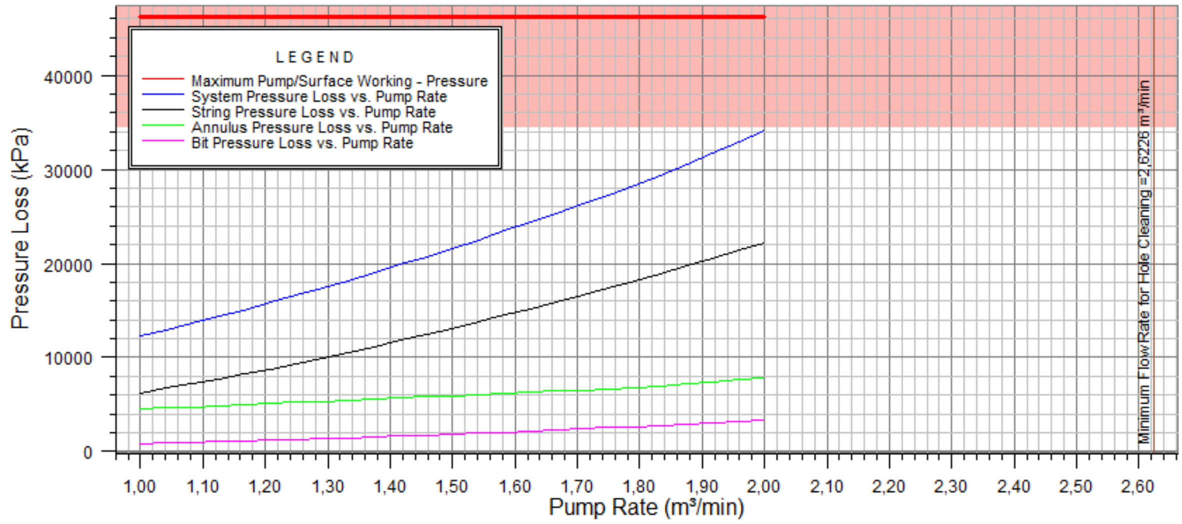

Figure 49: Pump rate range pressure loss for Transocean at 13000m horizontal extension (WELLPLAN).

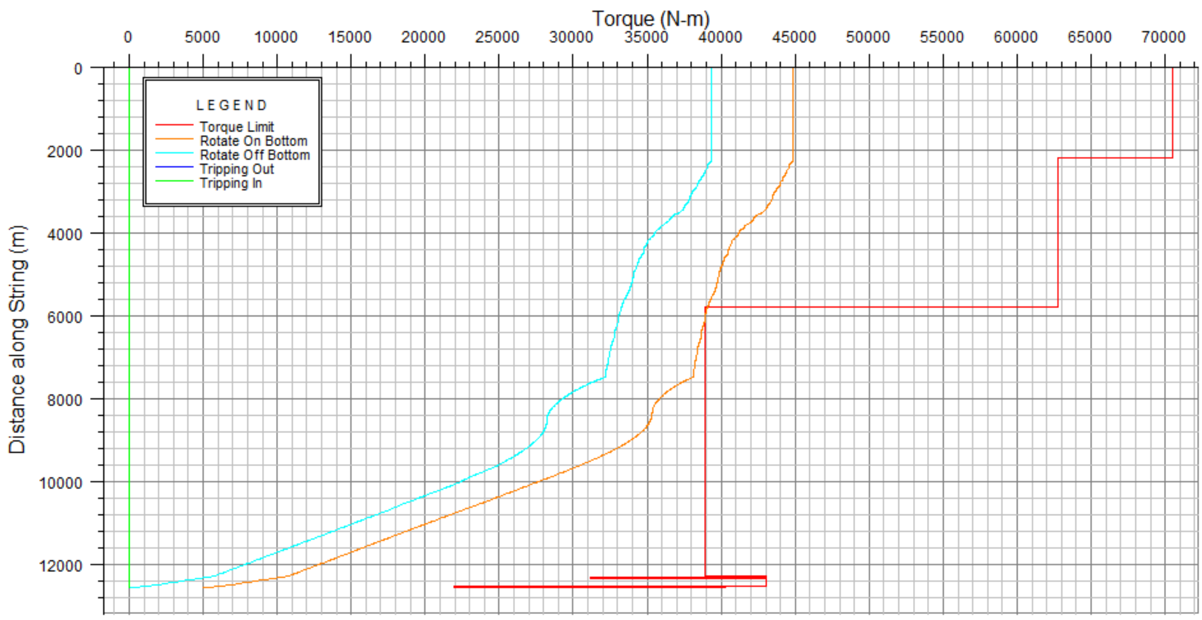

Figure 50: Torque graph for 1000m vertical extension (WELLPLAN).

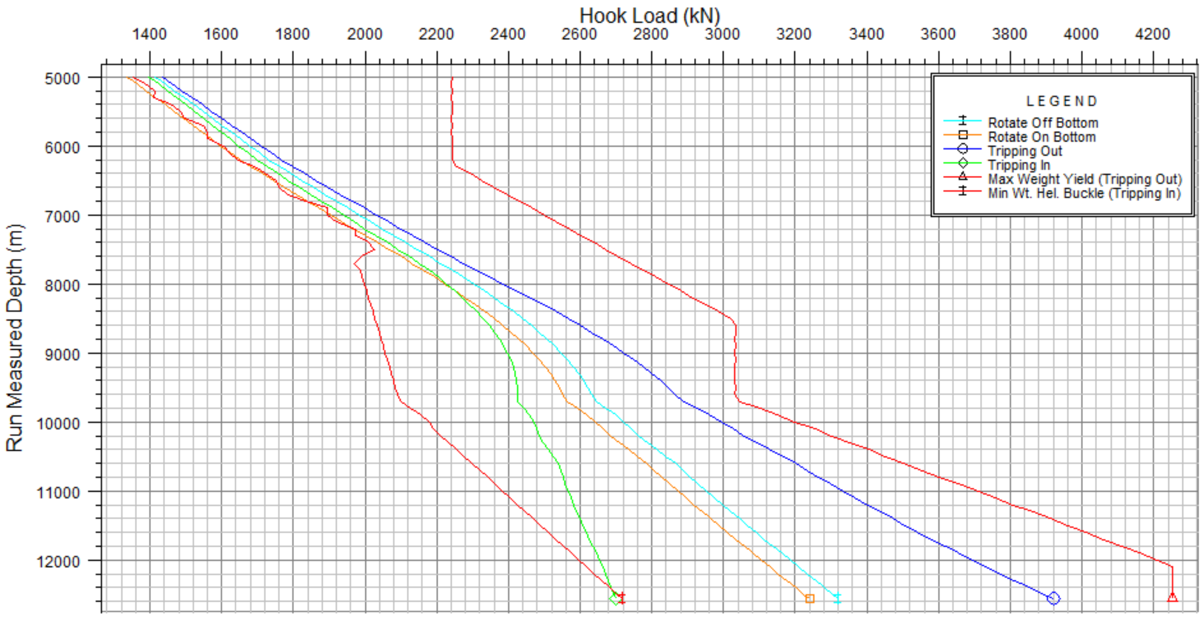

Figure 51: Hook load chart for 1000m vertical extension, casing set at 9000m (WELLPLAN).

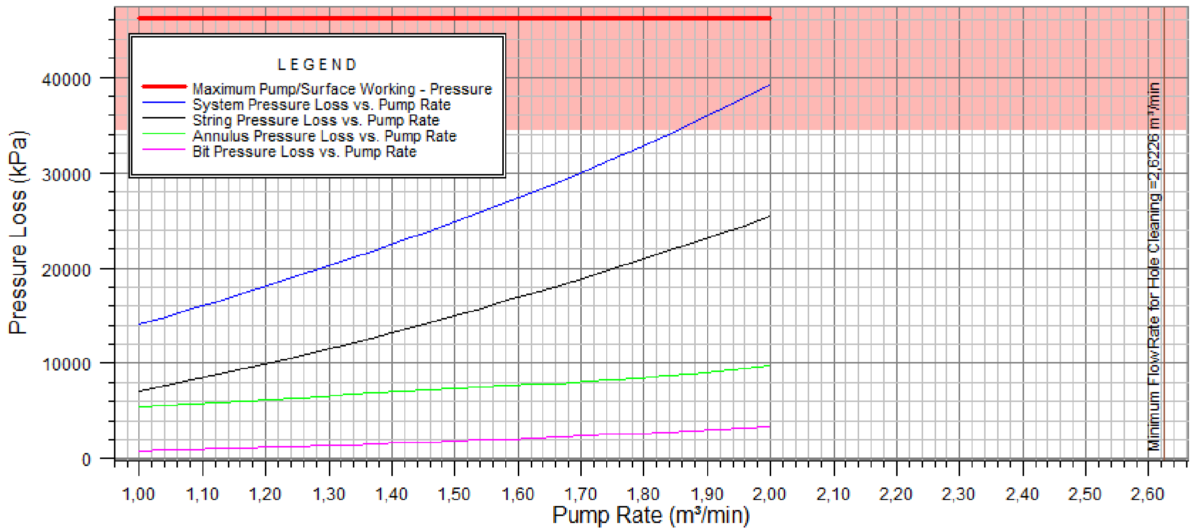

Figure 52: Pump rate pressure loss for Transocean at 1000m vertical extension (WELLPLAN).

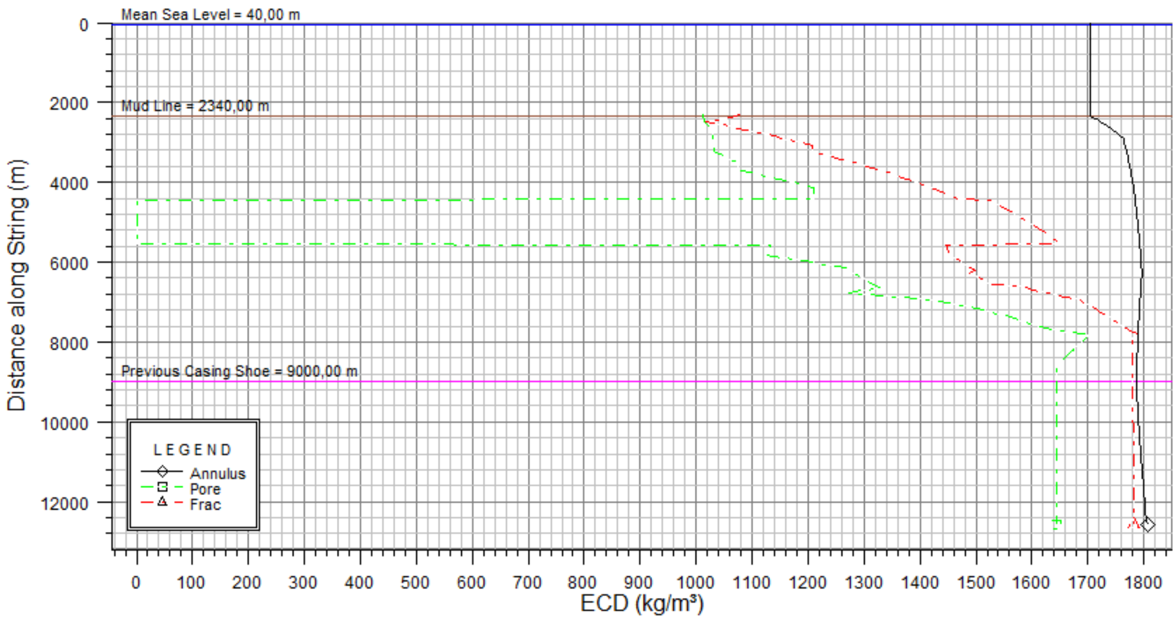

Figure 53: Transocean ECD vs. Depth graph for 1000m vertical extension (WELLPLAN).

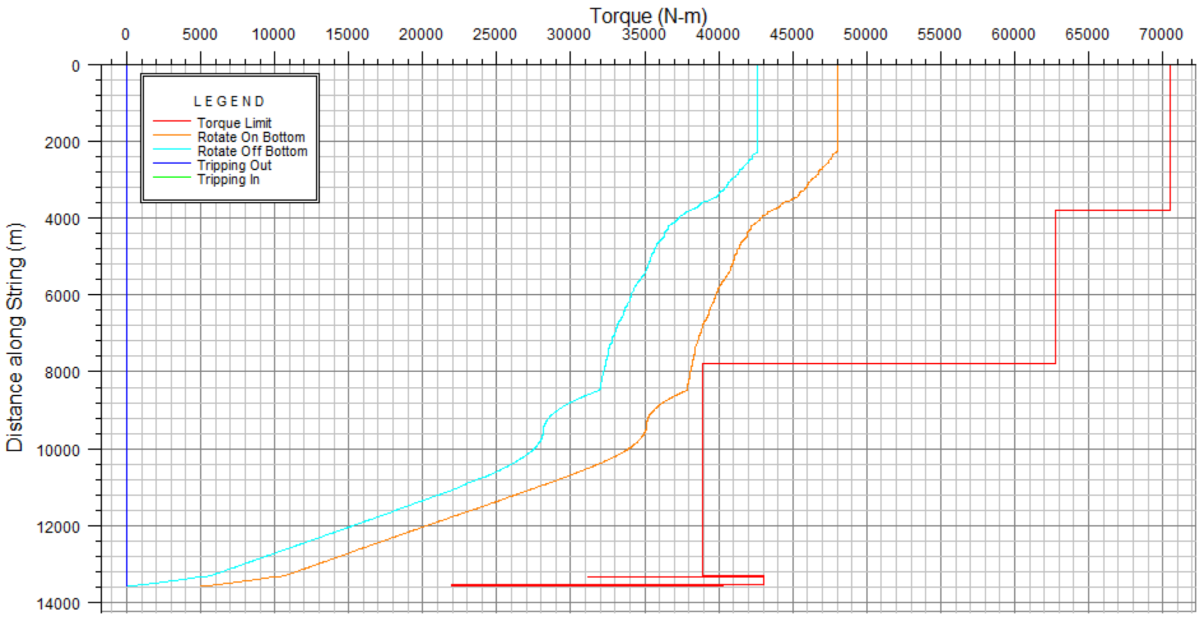

Figure 54: Torque chart for 2000m vertical extension (WELLPLAN).

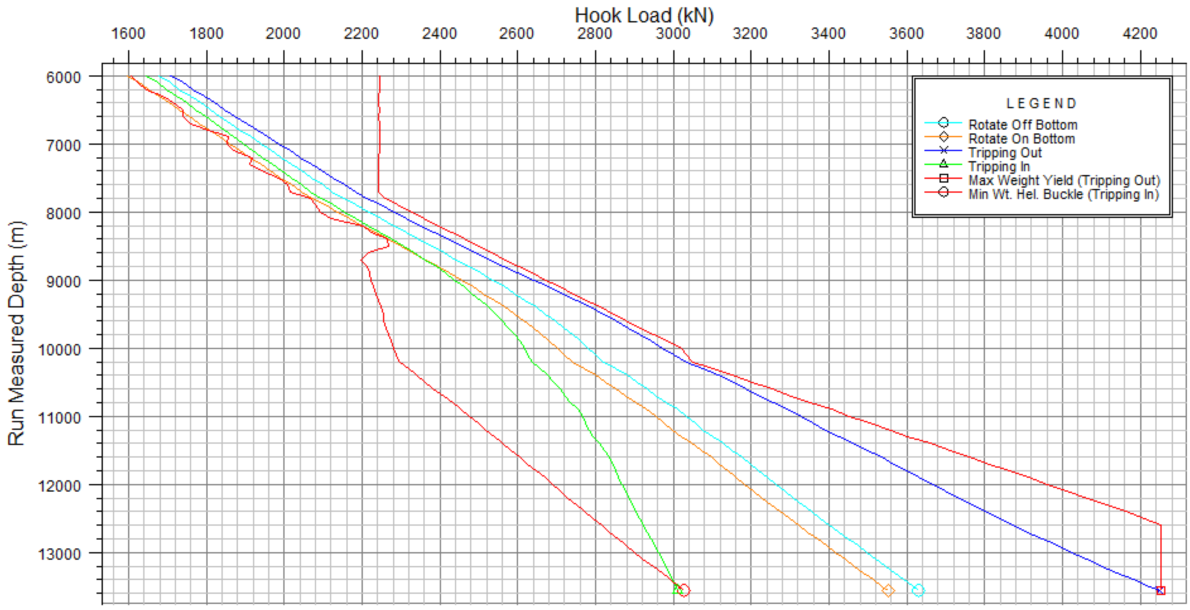

Figure 55: Hook load chart for Maersk, 2000m vertical extension (WELLPLAN).

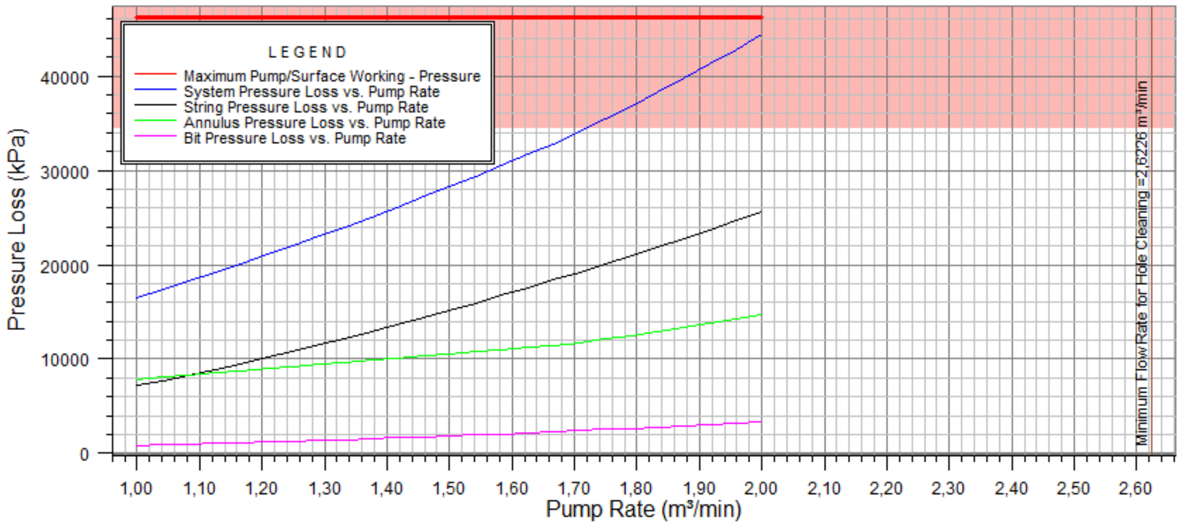

Figure 56: Pump rate range pressure loss for Transocean at 2000m vertical extension (WELLPLAN).

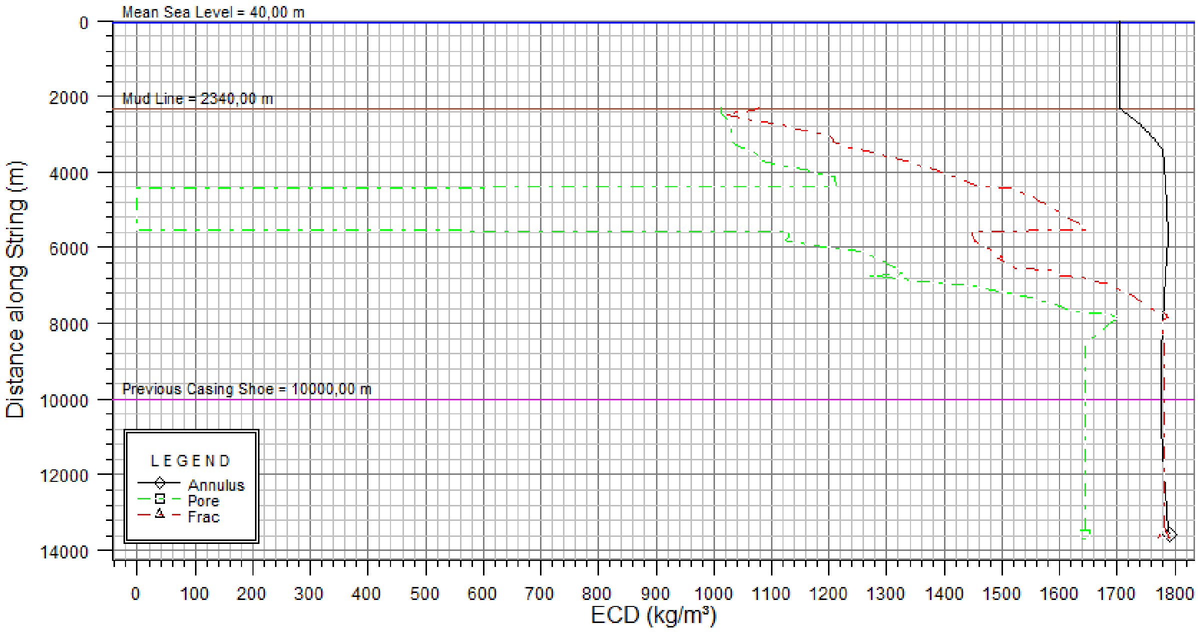

Figure 57: ECD vs. Depth graph for Maersk, 2000m vertical extension (WELLPLAN).

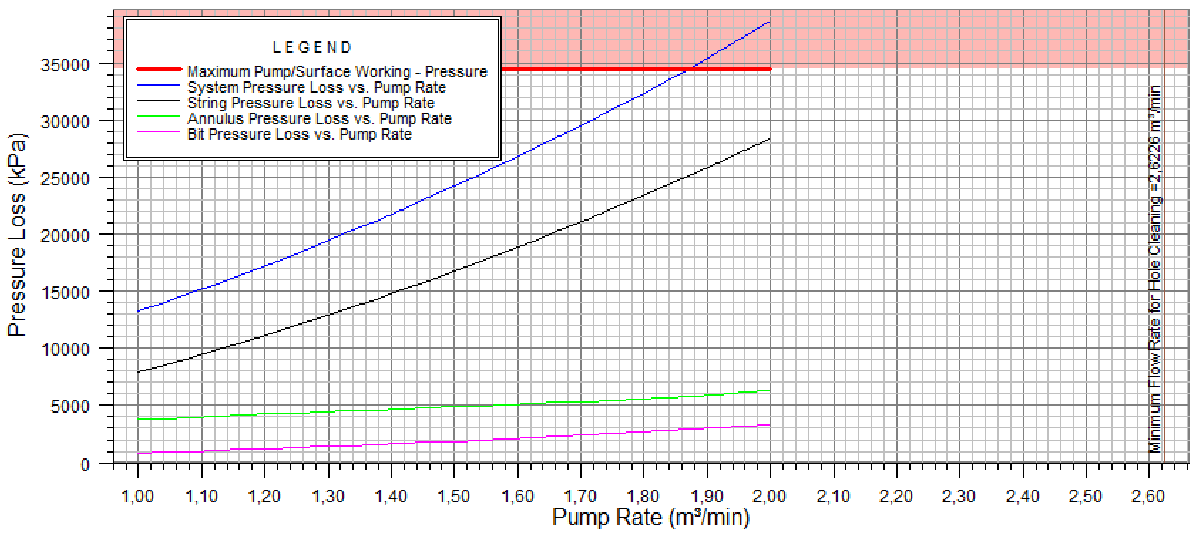

Figure 58: Pump rate range pressure loss for Maersk, at 2000m vertical extension (WELLPLAN).

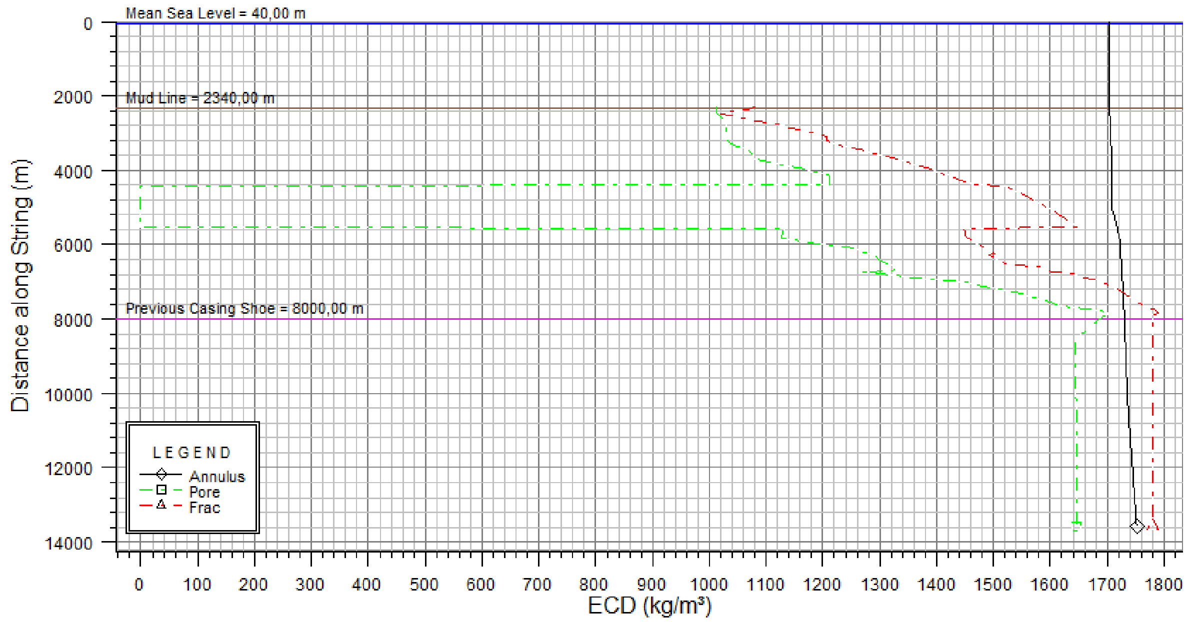

Figure 59: ECD vs. Depth for Maersk, 2000m vertical extension (WELLPLAN).

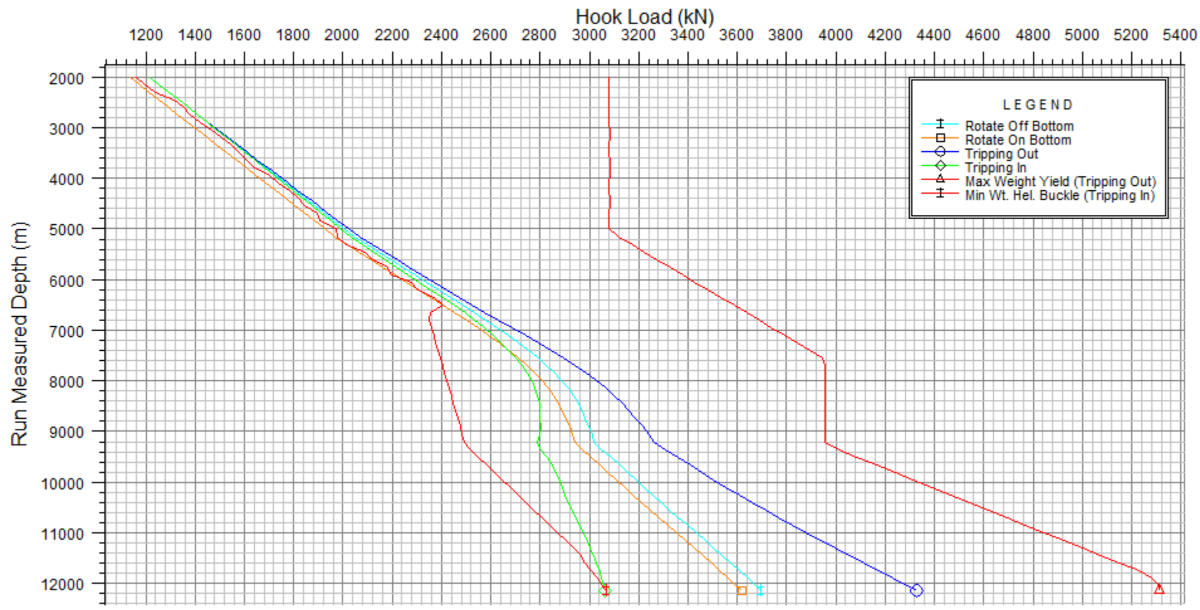

Figure 60: Hook load chart for 12150m horizontal extension, no DLS (WELLPLAN).

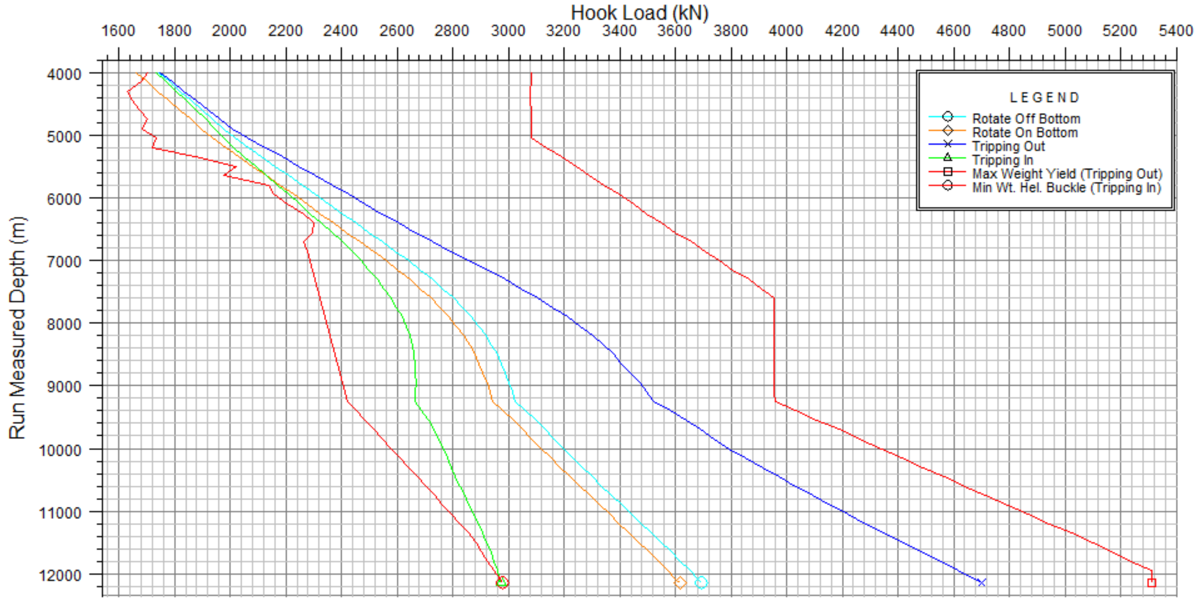

Figure 61: Hook load chart for 12150m horizontal extension, DLS1 (WELLPLAN).

Appendix C. Case and Sensitivity Study Data

	Section Type	Measured Depth (m)	Length (m)	ID (mm)	Drift (mm)	Effective Hole Diameter (mm)	Friction Factor	Linear Capacity (L/m)	Item Description
1	Riser	2335,80	2335,800	508,00			0,25	202,68	Riser: Vertical, OD = 533,4
2	Casing	5000,00	2664,200	315,34	311,38	315,34	0,25	78,04	13 3/8 in, 68 ppf, P-110,
3	Casing	10000,00	5000,000	216,79	215,90	216,79	0,25	36,95	9 5/8 in, 53.5 ppf, P-110,
4	Open Hole	13000,00	3000,000	215,90		215,90	0,30	36,61	

Figure 62: Hole section for 13000m horizontal extension (WELLPLAN).

	Section Type	Length (m)	Measured Depth (m)	OD (mm)	ID (mm)	Weight (kg/m)	Item Description
1	Drill Pipe	4236,134	4236,13	168,28	141,76	61,65	Drill Pipe 6 5/8 in, 34.02 ppf, S-135, 6 5/8 FH, P
2	Drill Pipe	4600,000	8836,13	149,22	128,14	41,82	Drill Pipe 5 7/8 in, 26.70 ppf, S-135, VAM Express, P
3	Drill Pipe	3900,000	12736,13	127,00	108,61	33,66	Drill Pipe 5 in, 19.50 ppf, S-135, NC50 VAM EIS, P
4	Heavy Weight	27,000	12763,13	127,00	76,20	74,62	Heavy Weight Drill Pipe, 5,000 in, 50,14 ppf, 1340 MOD, 5 1/2 FH
5	Jar	9,449	12772,58	165,10	69,85	136,60	Hydraulic Jar Dailey Hyd., 6 1/2 in
6	Heavy Weight	192,024	12964,61	127,00	76,20	74,62	Non-Mag Heavy Weight, 5,000 in, 50,14 ppf, 1340 MOD, 5 1/2 FH
7	Stabilizer	9,449	12974,06	171,45	71,37	134,41	FPWD Tool
8	MWD	9,499	12983,55	171,45	71,37	134,41	MWD Pulser
9	Stabilizer	7,681	12991,24	171,45	50,80	159,44	LWD GR/RES/DENS/NEUT
10	Heavy Weight	2,500	12993,74	127,00	76,20	73,13	RSS Flex
11	Stabilizer	1,524	12995,26	152,40	71,45	111,73	RSS Top Stab
12	Drill Collar	3,000	12998,26	171,45	76,20	143,92	RSS BODY
13	Stabilizer	1,500	12999,76	152,40	71,45	111,73	RSS Steering Head
14	Bit	0,240	13000,00	215,90		212,81	Polycrystalline Diamond Bit, 5x11, 0,464 in²

Figure 63: String section for 13000m horizontal extension (WELLPLAN).

Section Type	Measured Depth (m)	Length (m)	ID (mm)	Drift (mm)	Effective Hole Diameter (mm)	Friction Factor	Linear Capacity (L/m)	Item Description
Riser	2335,80	2335,800	508,00			0,25	202,68	Riser: Vertical, OD = 533,4
Casing	5000,00	2664,200	315,34	311,38	315,34	0,25	78,04	13 3/8 in, 68 ppf, P-110,
Casing	8000,00	3000,000	216,79	215,90	216,79	0,25	36,95	9 5/8 in, 53.5 ppf, P-110,
Open Hole	13563,75	5563,750	215,90		215,90	0,25	36,61	

Figure 64: Hole section for 2000m vertical extension (WELLPLAN).

Section Type	Length (m)	Measured Depth (m)	OD (mm)	ID (mm)	Weight (kg/m)	Item Description
Drill Pipe	3399,884	3399,88	168,28	141,76	61,65	Drill Pipe 6 5/8 in, 34.02 ppf, S-135, 6 5/8 FH, P
Drill Pipe	2400,000	5799,88	149,22	128,14	41,82	Drill Pipe 5 7/8 in, 26.70 ppf, S-135, VAM Express, P
Drill Pipe	7500,000	13299,88	127,00	108,61	33,66	Drill Pipe 5 in, 19.50 ppf, S-135, NC50 VAM EIS, P
Heavy Weight	27,000	13326,88	127,00	76,20	74,62	Heavy Weight Drill Pipe, 5,000 in, 50,14 ppf, 1340 MOD, 5 1/2 FH
Jar	9,449	13336,33	165,10	69,85	136,60	Hydraulic Jar Dailey Hyd., 6 1/2 in
Heavy Weight	192,024	13528,36	127,00	76,20	74,62	Non-Mag Heavy Weight, 5,000 in, 50,14 ppf, 1340 MOD, 5 1/2 FH
Stabilizer	9,449	13537,81	171,45	71,37	134,41	FPWD Tool
MWD	9,499	13547,30	171,45	71,37	134,41	MWD Pulser
Stabilizer	7,681	13554,99	171,45	50,80	159,44	LWD GR/RES/DENS/NEUT
Heavy Weight	2,500	13557,49	127,00	76,20	73,13	RSS Flex
Stabilizer	1,524	13559,01	152,40	71,45	111,73	RSS Top Stab
Drill Collar	3,000	13562,01	171,45	76,20	143,92	RSS BODY
Stabilizer	1,500	13563,51	152,40	71,45	111,73	RSS Steering Head
Bit	0,240	13563,75	215,90		212,81	Polycrystalline Diamond Bit, 5x11, 0,464 in²

Figure 65: String section for 2000m vertical extension (WELLPLAN).

Friction factor	Trip out max	Trip in max	Drag out max	Drag in max
OH=0.38 CH=0.33	100,0 %	100,0 %	100,0 %	100,0 %
OH=0.33 CH=0.33	98,5 %	102,4 %	89,3 %	88,5 %
OH=0.38 CH=0.25	98,2 %	102,5 %	87,2 %	87,7 %
OH=0.30 CH=0.25	96,0 %	105,8 %	72,1 %	71,7 %
OH=0.24 CH=0.25	94,5 %	108,1 %	62,0 %	60,5 %
OH=0.30 CH=0.18	94,7 %	107,5 %	62,8 %	63,5 %
OH=0.24 CH=0.18	93,3 %	109,7 %	53,4 %	53,1 %

Table 19: Percentage increase and decrease in drag and tripping when friction factor is decreased.

Mud density	Trip out max	Trip in max	Drag out max	Drag in max
117,6 %	96,0 %	96,2 %	95,4 %	95,5 %
105,9 %	98,7 %	98,7 %	98,5 %	98,5 %
100,0 %	100,0 %	100,0 %	100,0 %	100,0 %
94,1 %	101,3 %	101,3 %	101,5 %	101,5 %
88,2 %	102,7 %	102,5 %	103,1 %	103,0 %

Table 20: Percentage increase and decrease in drag and tripping when altering mud weight.

Mud density	Rotate on bottom max	Rotate off bottom max	ECD	System pressure loss @ 2.0pump rate
117,6 %	96,0 %	96,1 %	116,9 %	110,9 %
105,9 %	98,7 %	98,7 %	105,7 %	103,8 %
100,0 %	100,0 %	100,0 %	100,0 %	100,0 %
94,1 %	101,3 %	101,3 %	94,3 %	96,0 %
88,2 %	102,7 %	102,6 %	88,8 %	91,9 %

Table 21: Percentage increase and decrease in rotating and hydraulics when altering mud weight.

Friction factor	Rotate on bottom	Rotate off bottom
OH=0.38 CH=0.33	100,00 %	100,00 %
OH=0.33 CH=0.33	92,62 %	91,69 %
OH=0.38 CH=0.25	92,17 %	91,07 %
OH=0.30 CH=0.25	80,37 %	77,77 %
OH=0.24 CH=0.25	71,51 %	67,80 %
OH=0.30 CH=0.18	73,52 %	69,96 %
OH=0.24 CH=0.18	64,66 %	59,99 %

Table 22: Percentage decrease in torque when friction factor is decreased.

Mud density	Rotate on bottom	Rotate off bottom
117,65 %	96,10 %	95,49 %
105,88 %	98,70 %	98,49 %
100,00 %	100,00 %	100,00 %
94,12 %	101,31 %	101,51 %
88,24 %	102,62 %	103,02 %

Table 23: Percentage increase and decrease in torque when altering mud weight.

Appendix D. Well Trajectory for Base Case and DLS

MD (m)	INC (°)	AZ (°)	TVD (m)	DLS (°/30m)	AbsTort (°/30m)	RelTort (°/30m)	VSect (m)	North (m)	East (m)	Build (°/30m)	Walk (°/30m)
4092	1	320	4092	1	0,007	0	0,16	0,2	-0,17	1	0
4122	1	320	4121,99	0	0,007	0	0,48	0,6	-0,5	0	0
4152	2	265	4151,98	1,645	0,019	0	1,17	0,76	-1,19	1	-55
4182	2	265	4181,97	0	0,019	0	2,21	0,67	-2,24	0	0
4212	3	265	4211,94	1	0,026	0	3,52	0,55	-3,54	1	0
4242	3	265	4241,9	0	0,026	0	5,09	0,41	-5,11	0	0
4272	3	265	4271,86	0	0,026	0	6,66	0,28	-6,67	0	0
4302	4	265	4301,8	1	0,032	0	8,48	0,12	-8,49	1	0
4332	4	265	4331,73	0	0,032	0	10,57	-0,06	-10,58	0	0
4362	4	265	4361,65	0	0,032	0	12,66	-0,25	-12,66	0	0
4392	4	265	4391,58	0	0,032	0	14,75	-0,43	-14,75	0	0
4422	5	265	4421,49	1	0,038	0	17,1	-0,63	-17,09	1	0
4452	5	265	4451,37	0	0,038	0	19,72	-0,86	-19,7	0	0
4482	5	265	4481,26	0	0,038	0	22,33	-1,09	-22,3	0	0
4512	5	265	4511,14	0	0,038	0	24,94	-1,32	-24,91	0	0
4542	5	265	4541,03	0	0,037	0	27,55	-1,55	-27,51	0	0
4572	5,5	265	4570,9	0,5	0,04	0	30,29	-1,79	-30,25	0,5	0
4602	5,5	265	4600,77	0	0,04	0	33,16	-2,04	-33,11	0	0
4632	5,5	265	4630,63	0	0,04	0	36,03	-2,29	-35,98	0	0
4662	5,5	265	4660,49	0	0,04	0	38,9	-2,54	-38,84	0	0
4692	5,5	265	4690,35	0	0,039	0	41,77	-2,79	-41,7	0	0
4722	6	260	4720,2	0,707	0,044	0	44,76	-3,19	-44,68	0,5	-5
4752	6	250	4750,04	1,044	0,05	0	47,81	-3,99	-47,7	0	-10
4782	6	250	4779,87	0	0,05	0	50,79	-5,07	-50,64	0	0
4812	6,2	240	4809,7	1,08	0,056	0	53,71	-6,41	-53,52	0,2	-10
4842	6,2	220	4839,53	2,149	0,069	0	56,22	-8,46	-55,97	0	-20

4872	6,2	200	4869,36	2,149	0,082	0	57,91	-11,23	-57,56	0	-20
4902	6,2	160	4899,2	4,234	0,107	0	58,01	-14,27	-57,56	0	-40
4932	6	120	4929,04	4,17	0,132	0	56,18	-16,58	-55,65	-0,2	-40
4962	6	100	4958,88	2,08	0,144	0	53,32	-17,64	-52,75	0	-20
4992	6	80	4988,72	2,08	0,155	0	50,23	-17,64	-49,66	0	-20
5022	5,5	80	5018,57	0,5	0,157	0	47,25	-17,12	-46,7	-0,5	0
5052	5,5	60	5048,43	1,907	0,168	0	44,56	-16,15	-44,04	0	-20
5082	5,5	60	5078,29	0	0,167	0	42,02	-14,71	-41,55	0	0
5112	5,5	50	5108,16	0,957	0,171	0	39,62	-13,07	-39,2	0	-10
5142	5	50	5138,03	0,5	0,173	0	37,46	-11,3	-37,1	-0,5	0
5172	5	40	5167,92	0,87	0,177	0	35,56	-9,46	-35,26	0	-10
5202	5	40	5197,8	0	0,176	0	33,81	-7,46	-33,57	0	0
5232	5	40	5227,69	0	0,175	0	32,06	-5,45	-31,89	0	0
5262	5	40	5257,58	0	0,174	0	30,31	-3,45	-30,21	0	0
5292	4	40	5287,48	1	0,179	0	28,74	-1,65	-28,7	-1	0
5322	4	40	5317,41	0	0,178	0	27,34	-0,04	-27,36	0	0
5352	4	40	5347,34	0	0,177	0	25,94	1,56	-26,01	0	0
5382	4	40	5377,26	0	0,176	0	24,54	3,16	-24,66	0	0
5412	3	40	5407,21	1	0,181	0	23,32	4,56	-23,49	-1	0
5442	3	40	5437,17	0	0,18	0	22,27	5,77	-22,48	0	0
5472	3	40	5467,12	0	0,179	0	21,22	6,97	-21,47	0	0
5502	3	40	5497,08	0	0,178	0	20,17	8,17	-20,46	0	0
5532	2	40	5527,05	1	0,182	0	19,3	9,18	-19,62	-1	0
5562	2	40	5557,04	0	0,181	0	18,6	9,98	-18,95	0	0
5592	2	40	5587,02	0	0,18	0	17,9	10,78	-18,27	0	0
5622	1	40	5617,01	1	0,184	0	17,37	11,38	-17,77	-1	0
5652	1	30	5647	0,174	0,184	0	17,06	11,81	-17,47	0	-10
5682	1	30	5677	0	0,183	0	16,78	12,26	-17,21	0	0
5712	1	15	5706,99	0,261	0,184	0	16,56	12,74	-17,01	0	-15
5742	1	15	5736,99	0	0,183	0	16,41	13,25	-16,87	0	0

Table 24: Well trajectory data for DLS 1 (WELLPLAN).

MD (m)	INC (°)	AZ (°)	TVD (m)	DLS (°/30m)	AbsTort (°/30m)	RelTort (°/30m)	VSect (m)	North (m)	East (m)	Build (°/30m)	Walk (°/30m)
4002	1	270	4002	1	0,007	0	0,26	0	-0,26	1	0
4032	1	270	4031,99	0	0,007	0	0,78	0	-0,79	0	0
4062	1	270	4061,99	0	0,007	0	1,31	0	-1,31	0	0
4092	2	265	4091,98	1,008	0,015	0	2,09	-0,05	-2,09	1	-5
4122	2	265	4121,96	0	0,015	0	3,14	-0,14	-3,14	0	0
4152	2	265	4151,94	0	0,015	0	4,18	-0,23	-4,18	0	0
4182	3	265	4181,91	1	0,022	0	5,49	-0,34	-5,48	1	0
4212	3	265	4211,87	0	0,021	0	7,06	-0,48	-7,05	0	0
4242	4	265	4241,82	1	0,028	0	8,89	-0,64	-8,87	1	0
4272	4	265	4271,74	0	0,028	0	10,98	-0,82	-10,96	0	0
4302	6	265	4301,63	2	0,042	0	13,59	-1,05	-13,56	2	0
4332	6	265	4331,46	0	0,042	0	16,72	-1,32	-16,68	0	0
4362	8	265	4361,24	2	0,055	0	20,37	-1,64	-20,33	2	0
4392	8	265	4390,95	0	0,055	0	24,54	-2	-24,48	0	0
4422	10	265	4420,57	2	0,068	0	29,23	-2,41	-29,16	2	0
4452	10	265	4450,12	0	0,067	0	34,43	-2,87	-34,35	0	0
4482	13	265	4479,51	3	0,087	0	40,4	-3,39	-40,31	3	0
4512	13	260	4508,75	1,124	0,094	0	47,11	-4,27	-46,99	0	-5
4542	15	260	4537,85	2	0,107	0	54,3	-5,53	-54,14	2	0
4572	15	255	4566,83	1,294	0,114	0	61,92	-7,21	-61,71	0	-5
4602	20	255	4595,43	5	0,146	0	70,71	-9,54	-70,42	5	0
4632	20	255	4623,62	0	0,145	0	80,7	-12,2	-80,33	0	0
4662	20	180	4652,24	24,035	0,299	0	85,95	-18,75	-85,36	0	-75
4692	20	180	4680,43	0	0,297	0	86,3	-29,01	-85,36	0	0
4722	18	90	4709,31	26,658	0,465	0	81,76	-34,24	-80,64	-2	-90
4752	18	90	4737,84	0	0,462	0	72,5	-34,24	-71,37	0	0

4782	15	70	4766,63	6,38	0,499	0	64,16	-32,91	-63,08	-3	-20
4812	15	70	4795,61	0	0,496	0	56,78	-30,25	-55,78	0	0
4842	15	70	4824,58	0	0,493	0	49,4	-27,6	-48,49	0	0
4872	13	60	4853,69	3,132	0,509	0	42,73	-24,58	-41,92	-2	-10
4902	13	60	4882,93	0	0,506	0	36,77	-21,21	-36,07	0	0
4932	10	55	4912,32	3,159	0,522	0	31,61	-18,03	-31,01	-3	-5
4962	10	55	4941,87	0	0,519	0	27,24	-15,04	-26,75	0	0
4992	10	50	4971,41	0,868	0,521	0	23,01	-11,87	-22,62	0	-5
5022	8	50	5001,04	2	0,53	0	19,31	-8,85	-19,02	-2	0
5052	8	45	5030,75	0,696	0,531	0	16,14	-6,03	-15,95	0	-5
5082	8	45	5060,46	0	0,527	0	13,09	-3,08	-13	0	0
5112	6	40	5090,23	2,089	0,537	0	10,52	-0,4	-10,51	-2	-5
5142	6	40	5120,07	0	0,533	0	8,42	2	-8,5	0	0
5172	5	40	5149,93	1	0,536	0	6,5	4,2	-6,65	-1	0
5202	5	40	5179,81	0	0,533	0	4,75	6,2	-4,97	0	0
5232	4	40	5209,72	1	0,536	0	3,18	8,01	-3,45	-1	0
5262	4	40	5239,65	0	0,533	0	1,78	9,61	-2,11	0	0
5292	3	40	5269,59	1	0,535	0	0,56	11,01	-0,93	-1	0
5322	3	40	5299,55	0	0,532	0	-0,49	12,21	0,08	0	0
5352	2	40	5329,52	1	0,535	0	-1,37	13,22	0,92	-1	0
5382	2	40	5359,5	0	0,532	0	-2,07	14,02	1,59	0	0
5412	1	40	5389,49	1	0,535	0	-2,59	14,62	2,1	-1	0

Table 25: Well trajectory data for DLS 2 (WELLPLAN).

MD (m)	INC (°)	AZ (°)	TVD (m)	DLS (°/30m)	AbsTort (°/30m)	RelTort (°/30m)	VSect (m)	North (m)	East (m)	Build (°/30m)	Walk (°/30m)
0	0	0	0	0	0	0	0	0	0	0	0
2340	0	0	2340	0	0	0	0	0	0	0	0
2352	0	0	2352	0	0	0	0	0	0	0	0
2382	0	0	2382	0	0	0	0	0	0	0	0
2412	0	0	2412	0	0	0	0	0	0	0	0
2442	0	0	2442	0	0	0	0	0	0	0	0
2472	0	0	2472	0	0	0	0	0	0	0	0
2502	0	0	2502	0	0	0	0	0	0	0	0
2532	0	0	2532	0	0	0	0	0	0	0	0
2562	0	0	2562	0	0	0	0	0	0	0	0
2592	0	0	2592	0	0	0	0	0	0	0	0
2622	0	0	2622	0	0	0	0	0	0	0	0
2652	0	0	2652	0	0	0	0	0	0	0	0
2682	0	0	2682	0	0	0	0	0	0	0	0
2712	0	0	2712	0	0	0	0	0	0	0	0
2742	0	0	2742	0	0	0	0	0	0	0	0
2772	0	0	2772	0	0	0	0	0	0	0	0
2802	0	0	2802	0	0	0	0	0	0	0	0
2832	0	0	2832	0	0	0	0	0	0	0	0
2862	0	0	2862	0	0	0	0	0	0	0	0
2892	0	0	2892	0	0	0	0	0	0	0	0
2922	0	0	2922	0	0	0	0	0	0	0	0
2952	0	0	2952	0	0	0	0	0	0	0	0
2982	0	0	2982	0	0	0	0	0	0	0	0
3012	0	0	3012	0	0	0	0	0	0	0	0
3042	0	0	3042	0	0	0	0	0	0	0	0

3072	0	0	3072	0	0	0	0	0	0	0	0
3102	0	0	3102	0	0	0	0	0	0	0	0
3132	0	0	3132	0	0	0	0	0	0	0	0
3162	0	0	3162	0	0	0	0	0	0	0	0
3192	0	0	3192	0	0	0	0	0	0	0	0
3222	0	0	3222	0	0	0	0	0	0	0	0
3252	0	0	3252	0	0	0	0	0	0	0	0
3282	0	0	3282	0	0	0	0	0	0	0	0
3312	0	0	3312	0	0	0	0	0	0	0	0
3342	0	0	3342	0	0	0	0	0	0	0	0
3372	0	0	3372	0	0	0	0	0	0	0	0
3402	0	0	3402	0	0	0	0	0	0	0	0
3432	0	0	3432	0	0	0	0	0	0	0	0
3462	0	0	3462	0	0	0	0	0	0	0	0
3492	0	0	3492	0	0	0	0	0	0	0	0
3522	0	0	3522	0	0	0	0	0	0	0	0
3552	0	0	3552	0	0	0	0	0	0	0	0
3582	0	0	3582	0	0	0	0	0	0	0	0
3612	0	0	3612	0	0	0	0	0	0	0	0
3642	0	0	3642	0	0	0	0	0	0	0	0
3672	0	0	3672	0	0	0	0	0	0	0	0
3702	0	0	3702	0	0	0	0	0	0	0	0
3732	0	0	3732	0	0	0	0	0	0	0	0
3762	0	0	3762	0	0	0	0	0	0	0	0
3792	0	0	3792	0	0	0	0	0	0	0	0
3822	0	0	3822	0	0	0	0	0	0	0	0
3852	0	0	3852	0	0	0	0	0	0	0	0
3882	0	0	3882	0	0	0	0	0	0	0	0
3912	0	0	3912	0	0	0	0	0	0	0	0
3942	0	0	3942	0	0	0	0	0	0	0	0

3972	0	0	3972	0	0	0	0	0	0	0	0
4002	0	0	4002	0	0	0	0	0	0	0	0
4032	0	0	4032	0	0	0	0	0	0	0	0
4062	0	0	4062	0	0	0	0	0	0	0	0
4092	0	0	4092	0	0	0	0	0	0	0	0
4122	0	0	4122	0	0	0	0	0	0	0	0
4152	0	0	4152	0	0	0	0	0	0	0	0
4182	0	0	4182	0	0	0	0	0	0	0	0
4212	0	0	4212	0	0	0	0	0	0	0	0
4242	0	0	4242	0	0	0	0	0	0	0	0
4272	0	0	4272	0	0	0	0	0	0	0	0
4302	0	0	4302	0	0	0	0	0	0	0	0
4332	0	0	4332	0	0	0	0	0	0	0	0
4362	0	0	4362	0	0	0	0	0	0	0	0
4392	0	0	4392	0	0	0	0	0	0	0	0
4422	0	0	4422	0	0	0	0	0	0	0	0
4452	0	0	4452	0	0	0	0	0	0	0	0
4482	0	0	4482	0	0	0	0	0	0	0	0
4512	0	0	4512	0	0	0	0	0	0	0	0
4542	0	0	4542	0	0	0	0	0	0	0	0
4572	0	0	4572	0	0	0	0	0	0	0	0
4602	0	0	4602	0	0	0	0	0	0	0	0
4632	0	0	4632	0	0	0	0	0	0	0	0
4662	0	0	4662	0	0	0	0	0	0	0	0
4692	0	0	4692	0	0	0	0	0	0	0	0
4722	0	0	4722	0	0	0	0	0	0	0	0
4752	0	0	4752	0	0	0	0	0	0	0	0
4782	0	0	4782	0	0	0	0	0	0	0	0
4812	0	0	4812	0	0	0	0	0	0	0	0
4842	0	0	4842	0	0	0	0	0	0	0	0

4872	0	0	4872	0	0	0	0	0	0	0	0
4902	0	0	4902	0	0	0	0	0	0	0	0
4932	0	0	4932	0	0	0	0	0	0	0	0
4962	0	0	4962	0	0	0	0	0	0	0	0
4992	0	0	4992	0	0	0	0	0	0	0	0
5022	0	0	5022	0	0	0	0	0	0	0	0
5052	0	0	5052	0	0	0	0	0	0	0	0
5082	0	0	5082	0	0	0	0	0	0	0	0
5112	0	0	5112	0	0	0	0	0	0	0	0
5142	0	0	5142	0	0	0	0	0	0	0	0
5172	0	0	5172	0	0	0	0	0	0	0	0
5202	0	0	5202	0	0	0	0	0	0	0	0
5232	0	0	5232	0	0	0	0	0	0	0	0
5262	0	0	5262	0	0	0	0	0	0	0	0
5292	0	0	5292	0	0	0	0	0	0	0	0
5322	0	0	5322	0	0	0	0	0	0	0	0
5352	0	0	5352	0	0	0	0	0	0	0	0
5382	0	0	5382	0	0	0	0	0	0	0	0
5412	0	0	5412	0	0	0	0	0	0	0	0
5442	0	0	5442	0	0	0	0	0	0	0	0
5472	0	0	5472	0	0	0	0	0	0	0	0
5502	0	0	5502	0	0	0	0	0	0	0	0
5532	0	0	5532	0	0	0	0	0	0	0	0
5562	0	0	5562	0	0	0	0	0	0	0	0
5592	0	0	5592	0	0	0	0	0	0	0	0
5622	0	0	5622	0	0	0	0	0	0	0	0
5652	0	0	5652	0	0	0	0	0	0	0	0
5682	0	0	5682	0	0	0	0	0	0	0	0
5712	0	0	5712	0	0	0	0	0	0	0	0
5742	0	0	5742	0	0	0	0	0	0	0	0

5772	0	0	5772	0	0	0	0	0	0	0	0
5802	0	0	5802	0	0	0	0	0	0	0	0
5832	0	0	5832	0	0	0	0	0	0	0	0
5862	0	0	5862	0	0	0	0	0	0	0	0
5892	0	0	5892	0	0	0	0	0	0	0	0
5922	0	0	5922	0	0	0	0	0	0	0	0
5952	0	0	5952	0	0	0	0	0	0	0	0
5982	0	0	5982	0	0	0	0	0	0	0	0
6012	0	0	6012	0	0	0	0	0	0	0	0
6042	0	0	6042	0	0	0	0	0	0	0	0
6072	0	0	6072	0	0	0	0	0	0	0	0
6102	0	0	6102	0	0	0	0	0	0	0	0
6132	0	0	6132	0	0	0	0	0	0	0	0
6162	0	0	6162	0	0	0	0	0	0	0	0
6192	0	0	6192	0	0	0	0	0	0	0	0
6222	0	0	6222	0	0	0	0	0	0	0	0
6252	0	0	6252	0	0	0	0	0	0	0	0
6282	0	0	6282	0	0	0	0	0	0	0	0
6312	0	0	6312	0	0	0	0	0	0	0	0
6342	0	0	6342	0	0	0	0	0	0	0	0
6372	0	0	6372	0	0	0	0	0	0	0	0
6402	0	0	6402	0	0	0	0	0	0	0	0
6432	0	0	6432	0	0	0	0	0	0	0	0
6462	0	0	6462	0	0	0	0	0	0	0	0
6483,46	0	0	6483,46	0	0	0	0	0	0	0	0
6492	0,28	270,5	6492	0,984	0,001	0	0,02	0	-0,02	0,984	0
6522	1,28	270,5	6522	1	0,006	0	0,43	0	-0,43	1	0
6552	2,28	270,5	6551,98	1	0,01	0	1,36	0,01	-1,36	1	0
6582	3,28	270,5	6581,95	1	0,015	0	2,81	0,02	-2,82	1	0
6612	4,28	270,5	6611,88	1	0,019	0	4,79	0,04	-4,79	1	0

6642	5,28	270,5	6641,78	1	0,024	0	7,29	0,06	-7,29	1	0
6672	6,28	270,5	6671,62	1	0,028	0	10,31	0,09	-10,31	1	0
6702	7,28	270,5	6701,41	1	0,033	0	13,84	0,12	-13,86	1	0
6732	8,28	270,5	6731,14	1	0,037	0	17,9	0,16	-17,92	1	0
6762	9,28	270,5	6760,78	1	0,041	0	22,48	0,2	-22,5	1	0
6792	10,28	270,5	6790,35	1	0,045	0	27,57	0,24	-27,59	1	0
6822	11,28	270,5	6819,82	1	0,05	0	33,17	0,29	-33,2	1	0
6852	12,28	270,5	6849,19	1	0,054	0	39,29	0,34	-39,33	1	0
6882	13,28	270,5	6878,44	1	0,058	0	45,92	0,4	-45,96	1	0
6912	14,28	270,5	6907,58	1	0,062	0	53,06	0,46	-53,11	1	0
6942	15,28	270,5	6936,59	1	0,066	0	60,71	0,53	-60,76	1	0
6972	16,28	270,5	6965,45	1	0,07	0	68,86	0,6	-68,92	1	0
7002	17,28	270,5	6994,18	1	0,074	0	77,51	0,68	-77,58	1	0
7032	18,28	270,5	7022,74	1	0,078	0	86,66	0,76	-86,74	1	0
7062	19,28	270,5	7051,15	1	0,082	0	96,31	0,84	-96,4	1	0
7092	20,28	270,5	7079,38	1	0,086	0	106,46	0,93	-106,55	1	0
7122	21,28	270,5	7107,42	1	0,09	0	117,09	1,02	-117,19	1	0
7152	22,28	270,5	7135,28	1	0,093	0	128,21	1,12	-128,32	1	0
7182	23,28	270,5	7162,94	1	0,097	0	139,82	1,22	-139,94	1	0
7212	24,28	270,5	7190,39	1	0,101	0	151,9	1,33	-152,03	1	0
7242	25,28	270,5	7217,63	1	0,105	0	164,46	1,44	-164,61	1	0
7272	26,28	270,5	7244,65	1	0,108	0	177,5	1,55	-177,65	1	0
7302	27,28	270,5	7271,43	1	0,112	0	191	1,67	-191,17	1	0
7332	28,28	270,5	7297,97	1	0,116	0	204,97	1,79	-205,15	1	0
7362	29,28	270,5	7324,26	1	0,119	0	219,4	1,92	-219,6	1	0
7392	30,28	270,5	7350,3	1	0,123	0	234,29	2,05	-234,49	1	0
7422	31,28	270,5	7376,07	1	0,126	0	249,63	2,18	-249,85	1	0
7452	32,28	270,5	7401,58	1	0,13	0	265,41	2,32	-265,65	1	0
7482	33,28	270,5	7426,8	1	0,133	0	281,64	2,46	-281,89	1	0
7512	34,28	270,5	7451,73	1	0,137	0	298,3	2,61	-298,57	1	0

7542	35,28	270,5	7476,37	1	0,14	0	315,4	2,75	-315,68	1	0
7572	36,28	270,5	7500,71	1	0,144	0	332,93	2,91	-333,22	1	0
7602	37,28	270,5	7524,74	1	0,147	0	350,87	3,06	-351,18	1	0
7632	38,28	270,5	7548,45	1	0,15	0	369,23	3,23	-369,56	1	0
7662	39,28	270,5	7571,84	1	0,154	0	388,01	3,39	-388,35	1	0
7692	40,28	270,5	7594,89	1	0,157	0	407,18	3,56	-407,54	1	0
7722	41,28	270,5	7617,61	1	0,16	0	426,76	3,73	-427,13	1	0
7752	42,28	270,5	7639,98	1	0,164	0	446,73	3,9	-447,12	1	0
7782	43,28	270,5	7662	1	0,167	0	467,09	4,08	-467,5	1	0
7812	44,28	270,5	7683,66	1	0,17	0	487,82	4,26	-488,25	1	0
7842	45,28	270,5	7704,95	1	0,173	0	508,94	4,45	-509,38	1	0
7872	46,28	270,5	7725,87	1	0,176	0	530,42	4,63	-530,88	1	0
7902	47,28	270,5	7746,42	1	0,179	0	552,26	4,82	-552,74	1	0
7932	48,28	270,5	7766,58	1	0,183	0	574,45	5,02	-574,96	1	0
7962	49,28	270,5	7786,35	1	0,186	0	597	5,21	-597,52	1	0
7992	50,28	270,5	7805,72	1	0,189	0	619,88	5,41	-620,43	1	0
8022	51,28	270,5	7824,69	1	0,192	0	643,1	5,62	-643,67	1	0
8052	52,28	270,5	7843,25	1	0,195	0	666,65	5,82	-667,24	1	0
8082	53,28	270,5	7861,39	1	0,198	0	690,52	6,03	-691,12	1	0
8112	54,28	270,5	7879,12	1	0,201	0	714,7	6,24	-715,33	1	0
8142	55,28	270,5	7896,42	1	0,204	0	739,18	6,46	-739,83	1	0
8172	56,28	270,5	7913,29	1	0,207	0	763,97	6,67	-764,64	1	0
8202	57,28	270,5	7929,73	1	0,21	0	789,04	6,89	-789,73	1	0
8232	58,28	270,5	7945,72	1	0,212	0	814,4	7,11	-815,11	1	0
8262	59,28	270,5	7961,27	1	0,215	0	840,03	7,34	-840,77	1	0
8292	60,28	270,5	7976,37	1	0,218	0	865,93	7,56	-866,69	1	0
8322	61,28	270,5	7991,01	1	0,221	0	892,09	7,79	-892,87	1	0
8352	62,28	270,5	8005,2	1	0,224	0	918,5	8,02	-919,3	1	0
8382	63,28	270,5	8018,92	1	0,226	0	945,15	8,26	-945,98	1	0
8412	64,28	270,5	8032,18	1	0,229	0	972,04	8,49	-972,89	1	0

8442	65,28	270,5	8044,96	1	0,232	0	999,15	8,73	-1000,03	1	0
8472	66,28	270,5	8057,27	1	0,235	0	1026,49	8,97	-1027,39	1	0
8502	67,28	270,5	8069,09	1	0,237	0	1054,03	9,21	-1054,96	1	0
8532	68,28	270,5	8080,44	1	0,24	0	1081,78	9,45	-1082,73	1	0
8562	69,28	270,5	8091,3	1	0,243	0	1109,72	9,69	-1110,69	1	0
8592	70,28	270,5	8101,67	1	0,245	0	1137,84	9,94	-1138,84	1	0
8622	71,28	270,5	8111,54	1	0,248	0	1166,15	10,19	-1167,17	1	0
8652	72,28	270,5	8120,92	1	0,251	0	1194,61	10,43	-1195,66	1	0
8682	73,28	270,5	8129,8	1	0,253	0	1223,24	10,68	-1224,32	1	0
8688,45	73,5	270,5	8131,65	1,023	0,254	0	1229,42	10,74	-1230,5	1,023	0
8712	73,5	270,5	8138,34	0	0,253	0	1251,98	10,94	-1253,08	0	0
8742	73,5	270,5	8146,86	0	0,252	0	1280,72	11,19	-1281,84	0	0
8772	73,5	270,5	8155,38	0	0,251	0	1309,45	11,44	-1310,6	0	0
8802	73,5	270,5	8163,9	0	0,251	0	1338,19	11,69	-1339,37	0	0
8832	73,5	270,5	8172,42	0	0,25	0	1366,93	11,94	-1368,13	0	0
8862	73,5	270,5	8180,94	0	0,249	0	1395,67	12,19	-1396,89	0	0
8888,43	73,5	270,5	8188,44	0	0,248	0	1420,99	12,41	-1422,23	0	0
8892	73,68	270,5	8189,45	1,513	0,249	0	1424,41	12,44	-1425,66	1,513	0
8922	75,18	270,46	8197,51	1,5	0,253	0	1453,28	12,68	-1454,56	1,5	-0,04
8952	76,68	270,42	8204,8	1,501	0,257	0	1482,36	12,91	-1483,65	1,5	-0,04
8982	78,18	270,38	8211,33	1,501	0,261	0	1511,61	13,11	-1512,93	1,5	-0,04
9012	79,68	270,34	8217,09	1,501	0,265	0	1541,03	13,3	-1542,37	1,5	-0,04
9042	81,18	270,3	8222,07	1,501	0,269	0	1570,59	13,46	-1571,96	1,5	-0,04
9045,22	81,34	270,3	8222,56	1,491	0,27	0	1573,77	13,48	-1575,14	1,491	0
9072	81,34	270,3	8226,6	0	0,269	0	1600,22	13,62	-1601,61	0	0
9102	81,34	270,3	8231,11	0	0,268	0	1629,86	13,77	-1631,27	0	0
9132	81,34	270,3	8235,63	0	0,267	0	1659,49	13,93	-1660,93	0	0
9162	81,34	270,3	8240,15	0	0,266	0	1689,13	14,08	-1690,58	0	0
9192	81,34	270,3	8244,66	0	0,265	0	1718,76	14,24	-1720,24	0	0
9222	81,34	270,3	8249,18	0	0,265	0	1748,4	14,39	-1749,9	0	0

9252	81,34	270,3	8253,7	0	0,264	0	1778,03	14,55	-1779,56	0	0
9282	81,34	270,3	8258,22	0	0,263	0	1807,67	14,7	-1809,21	0	0
9312	81,34	270,3	8262,73	0	0,262	0	1837,3	14,86	-1838,87	0	0
9342	81,34	270,3	8267,25	0	0,261	0	1866,94	15,01	-1868,53	0	0
9372	81,34	270,3	8271,77	0	0,26	0	1896,57	15,17	-1898,19	0	0
9402	81,34	270,3	8276,28	0	0,26	0	1926,21	15,32	-1927,85	0	0
9432	81,34	270,3	8280,8	0	0,259	0	1955,84	15,48	-1957,5	0	0
9462	81,34	270,3	8285,32	0	0,258	0	1985,48	15,64	-1987,16	0	0
9492	81,34	270,3	8289,84	0	0,257	0	2015,11	15,79	-2016,82	0	0
9522	81,34	270,3	8294,35	0	0,256	0	2044,75	15,95	-2046,48	0	0
9552	81,34	270,3	8298,87	0	0,255	0	2074,38	16,1	-2076,13	0	0
9573,43	81,34	270,3	8302,1	0	0,255	0	2095,55	16,21	-2097,32	0	0
9582	81,76	270,27	8303,36	1,474	0,256	0	2104,02	16,25	-2105,8	1,47	-0,105
9612	83,26	270,17	8307,27	1,503	0,26	0	2133,74	16,37	-2135,54	1,5	-0,1
9642	84,76	270,07	8310,4	1,503	0,264	0	2163,56	16,43	-2165,37	1,5	-0,1
9661,9	85,75	270	8312,04	1,496	0,266	0	2183,38	16,44	-2185,21	1,492	-0,106
9672	85,75	269,49	8312,79	1,511	0,268	0	2193,45	16,4	-2195,28	0	-1,515
9702	85,75	267,99	8315,01	1,496	0,271	0	2223,36	15,74	-2225,19	0	-1,5
9732	85,76	266,49	8317,24	1,496	0,275	0	2253,28	14,3	-2255,07	0,01	-1,5
9762	85,76	264,98	8319,45	1,506	0,279	0	2283,17	12,08	-2284,9	0	-1,51
9774,97	85,77	264,33	8320,41	1,5	0,281	0	2296,08	10,87	-2297,78	0,023	-1,503
9792	85,77	264,33	8321,67	0	0,28	0	2313,03	9,19	-2314,68	0	0
9822	85,77	264,33	8323,88	0	0,279	0	2342,88	6,24	-2344,45	0	0
9852	85,77	264,33	8326,09	0	0,278	0	2372,74	3,28	-2374,23	0	0
9882	85,77	264,33	8328,31	0	0,278	0	2402,59	0,32	-2404	0	0
9912	85,77	264,33	8330,52	0	0,277	0	2432,45	-2,63	-2433,77	0	0
9942	85,77	264,33	8332,73	0	0,276	0	2462,3	-5,59	-2463,54	0	0
9972	85,77	264,33	8334,94	0	0,275	0	2492,16	-8,54	-2493,31	0	0
9989,98	85,77	264,33	8336,27	0	0,275	0	2510,05	-10,31	-2511,16	0	0
10003,33	85,75	265	8337,26	1,502	0,276	0	2523,34	-11,55	-2524,41	-0,045	1,506

10025,42	86,83	265,21	8338,69	1,494	0,279	0	2545,36	-13,43	-2546,38	1,467	0,285
10032	86,83	265,21	8339,05	0	0,279	0	2551,92	-13,98	-2552,92	0	0
10062	86,83	265,21	8340,71	0	0,278	0	2581,84	-16,48	-2582,77	0	0
10092	86,83	265,21	8342,37	0	0,277	0	2611,75	-18,98	-2612,62	0	0
10122	86,83	265,21	8344,03	0	0,276	0	2641,67	-21,49	-2642,47	0	0
10152	86,83	265,21	8345,69	0	0,275	0	2671,59	-23,99	-2672,32	0	0
10182	86,83	265,21	8347,35	0	0,275	0	2701,51	-26,49	-2702,17	0	0
10212	86,83	265,21	8349	0	0,274	0	2731,42	-28,99	-2732,02	0	0
10242	86,83	265,21	8350,66	0	0,273	0	2761,34	-31,49	-2761,87	0	0
10272	86,83	265,21	8352,32	0	0,272	0	2791,26	-33,99	-2791,72	0	0
10302	86,83	265,21	8353,98	0	0,271	0	2821,18	-36,49	-2821,57	0	0
10332	86,83	265,21	8355,64	0	0,271	0	2851,09	-38,99	-2851,42	0	0
10362	86,83	265,21	8357,3	0	0,27	0	2881,01	-41,5	-2881,27	0	0
10392	86,83	265,21	8358,96	0	0,269	0	2910,93	-44	-2911,12	0	0
10422	86,83	265,21	8360,62	0	0,268	0	2940,84	-46,5	-2940,97	0	0
10452	86,83	265,21	8362,28	0	0,267	0	2970,76	-49	-2970,81	0	0
10482	86,83	265,21	8363,94	0	0,267	0	3000,68	-51,5	-3000,66	0	0
10512	86,83	265,21	8365,59	0	0,266	0	3030,6	-54	-3030,51	0	0
10542	86,83	265,21	8367,25	0	0,265	0	3060,51	-56,5	-3060,36	0	0
10572	86,83	265,21	8368,91	0	0,264	0	3090,43	-59,01	-3090,21	0	0
10602	86,83	265,21	8370,57	0	0,264	0	3120,35	-61,51	-3120,06	0	0
10620,18	86,83	265,21	8371,58	0	0,263	0	3138,48	-63,02	-3138,15	0	0
10626,67	87,08	265	8371,92	1,508	0,264	0	3144,95	-63,58	-3144,61	1,156	-0,971
10632	86,82	265,08	8372,21	1,531	0,265	0	3150,27	-64,04	-3149,91	-1,463	0,45
10654,97	85,72	265,4	8373,7	1,496	0,267	0	3173,16	-65,94	-3172,75	-1,437	0,418
10662	85,72	265,4	8374,22	0	0,267	0	3180,16	-66,5	-3179,74	0	0
10692	85,72	265,4	8376,46	0	0,266	0	3210,05	-68,9	-3209,56	0	0
10722	85,72	265,4	8378,7	0	0,266	0	3239,93	-71,3	-3239,38	0	0
10752	85,72	265,4	8380,94	0	0,265	0	3269,81	-73,7	-3269,2	0	0
10782	85,72	265,4	8383,18	0	0,264	0	3299,7	-76,1	-3299,02	0	0

10812	85,72	265,4	8385,42	0	0,263	0	3329,58	-78,5	-3328,84	0	0
10842	85,72	265,4	8387,66	0	0,263	0	3359,47	-80,9	-3358,66	0	0
10872	85,72	265,4	8389,9	0	0,262	0	3389,35	-83,29	-3388,48	0	0
10902	85,72	265,4	8392,14	0	0,261	0	3419,24	-85,69	-3418,3	0	0
10932	85,72	265,4	8394,37	0	0,261	0	3449,12	-88,09	-3448,12	0	0
10962	85,72	265,4	8396,61	0	0,26	0	3479,01	-90,49	-3477,94	0	0
10992	85,72	265,4	8398,85	0	0,259	0	3508,89	-92,89	-3507,76	0	0
11022	85,72	265,4	8401,09	0	0,258	0	3538,77	-95,29	-3537,58	0	0
11052	85,72	265,4	8403,33	0	0,258	0	3568,66	-97,69	-3567,4	0	0
11082	85,72	265,4	8405,57	0	0,257	0	3598,54	-100,09	-3597,22	0	0
11112	85,72	265,4	8407,81	0	0,256	0	3628,43	-102,49	-3627,04	0	0
11142	85,72	265,4	8410,05	0	0,256	0	3658,31	-104,89	-3656,86	0	0
11172	85,72	265,4	8412,29	0	0,255	0	3688,2	-107,29	-3686,68	0	0
11202	85,72	265,4	8414,52	0	0,254	0	3718,08	-109,69	-3716,5	0	0
11232	85,72	265,4	8416,76	0	0,254	0	3747,96	-112,09	-3746,32	0	0
11262	85,72	265,4	8419	0	0,253	0	3777,85	-114,48	-3776,14	0	0
11292	85,72	265,4	8421,24	0	0,252	0	3807,73	-116,88	-3805,96	0	0
11322	85,72	265,4	8423,48	0	0,252	0	3837,62	-119,28	-3835,78	0	0
11352	85,72	265,4	8425,72	0	0,251	0	3867,5	-121,68	-3865,6	0	0
11382	85,72	265,4	8427,96	0	0,25	0	3897,39	-124,08	-3895,42	0	0
11412	85,72	265,4	8430,2	0	0,25	0	3927,27	-126,48	-3925,24	0	0
11442	85,72	265,4	8432,44	0	0,249	0	3957,15	-128,88	-3955,06	0	0
11472	85,72	265,4	8434,67	0	0,248	0	3987,04	-131,28	-3984,88	0	0
11502	85,72	265,4	8436,91	0	0,248	0	4016,92	-133,68	-4014,7	0	0
11532	85,72	265,4	8439,15	0	0,247	0	4046,81	-136,08	-4044,52	0	0
11563,75	85,72	265,4	8441,52	0	0,246	0	4078,44	-138,62	-4076,08	0	0
11600	86	265,4	8444,14	0,232	0,246	0	4114,55	-141,52	-4112,12	0,232	0
11700	86,5	265,4	8450,68	0,15	0,245	0	4214,23	-149,52	-4211,58	0,15	0
11800	87	265,4	8456,35	0,15	0,245	0	4313,96	-157,53	-4311,1	0,15	0
11900	87,5	265,4	8461,15	0,15	0,244	0	4413,74	-165,54	-4410,66	0,15	0

12000	88	265,4	8465,07	0,15	0,243	0	4513,56	-173,55	-4510,26	0,15	0
12150	88	265,4	8470,31	0	0,24	0	4663,3	-185,57	-4659,69	0	0

Table 26: Well trajectory of the base case, values from WELLPLAN.