NTNU
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Experience Transfer in Drilling Operations

Brendan Savio Aranjo

Petroleum Engineering
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Supervisor: Sigbjørn Sangesland, IPT

Norwegian University of Science and Technology
Department of Petroleum Engineering and Applied Geophysics

Brendan Aranjo

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NTNU Norwegian University of Science and Technology
Faculty of Engineering Science and Technology
Department of Petroleum Engineering and Applied Geophysics

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Brendan Aranjo

Abstract

With the current economic climate most operators for deepwater drilling projects have tried to curb capital costs, particularly on drilling expenditure. Several operators have succeeded by focusing on operational improvements, such as reducing NPT, optimizing procurement practices or by improved management performance. Reducing costs by avoiding failure is an old practise in the oil industry. Practices to learn from failure has been ongoing for decades, as applying experienced learning is believed to be one of the main elements of low cost operations. This thesis provides a summary of experience from a full field development and an analysis of which areas experience transfer prove more valuable for saving cost and where it is not effective.

In general, most operators apply experience through drilling data and reports from previous wells drilled into the same field and analyse these to extract experience and transfer the experience learned into the well planning stage.
This study details how understanding sources of NPT and drilling experience followed by the successful extraction of experience from drilling data and transfer into the planning phase along with the experience from using numerical models and its results for well planning and how these are successful in reducing the probability of NPT events for the next well. This was done by designing a risk assessment and a short drilling program, using experience gained from wells drilled in the same or similar fields.

Further work would include studies to explore the methods of integrating experience transfer with planning and real time surveillance. This could be done using an online database and using case based reasoning systems to extract experience from the database and transfer this experience automatically into well planning software and real time drilling software to create an efficient experience transfer system to effectively reduce the risk of NPT related events.

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Abbreviations

NPT	Non Productive Time
BBL	Barrel
ROP	Rate of Penetration
ECD	Equivalent Circulating Density
MW	Mud Weight
TD	Total Depth
SG	Specific Gravity
RIH	Run in Hole
LCM	Lost Circulation Material
FIT	Formation Integrity Test
SPP	Stand Pipe Pressure
OOH	Out of Hole
EMW	Equivalent Mud Weight
B/U	Back Up
LWD	Logging While Drilling
WBM	Water Based Mud
WOB	Weight on Bit

MSL	Mean Sea Level
RKB	Rotary Kelly Bushing
TVD	Total Vertical Depth
MD	Measured Depth
LOT	Leak Off Test
Fm	Formation
OBM	Oil Based Mud
POOH	Pull Out Of Hole
RPM	Revolutions Per Minute
BHA	Bottom Hole Assembly
TOC	Top Off Cement
M/U	Make Up
R/B	Run Back
WL	Wire Line
RSS	Rotary Steering System
TFA	Total Flow Area
PDC	Polycrystalline Diamond Compact
LGS	Low Gravity Solids
HC	Hydro Carbon

1 Introduction

Complex reservoirs are in competition with the easier onshore fields. Advanced technology is often the solution to develop complex fields cost effectively. However, these fields are more susceptible for NPT since the cost per hour is often high.

As the drilling process gets more complex, the importance of drilling experience gained and effectively transferred is higher. Drilling experience is an event that occurs during the drilling process from which personnel can learn from to help improve existing knowledge for better development of planning and operations. The event can be related to geological or operational data leading to failure or improved performance. The outcome of the event is gained experience. Drilling experience can account for positive and negative events. With positive events, procedures are successful and personnel can learn from the positive aspects from these kind of experiences.

Negative experiences hold for common mistakes made and procedures leading towards Non Productive Time (NPT). Such procedures have a negative impact on the project and should be avoided in future projects.

Neutral experiences do not have a positive or negative impact on the project, but provides useful information that can be repeated in similar projects to avoid rework. Organizations can learn from previous positive and negative experiences and reduce costs of mistakes and reworking in projects.

Engineers in a project team have various skills and backgrounds. The project team will collectively have existing knowledge and solutions to execute project operations. Part of the existing knowledge and solutions is based on experience gained from past projects. More positive and negative experience will be gained during project execution. These experiences can help project teams to avoid previous errors and reworking, and use the positive side of the experiences to develop better planning and operations for future projects.

NPT is a direct consequence of negative experience; avoiding NPT in deepwater wells is critical especially during the current economic climate therefore this thesis will focus on the transfer of negative experience to mitigate NPT related events.

From interviews conducted with drilling engineers and the operational geologist for an operating company, it is understood that the industry practise is to use an ‘experience form’ to log experience manually along with daily operating reports. While a system is in place to manually log experience, this experience is not transferred when planning new wells and vital data in drilling reports and experience forms is left unused. With vast amounts of data present in the database, drilling engineers find it is tedious to explore and find the relevant experience required for planning the next well, this leads to higher probability of NPT for the forthcoming well. This thesis study will define experience and will involve the analysis of drilling data and how negative experience extracted from drilling data can be highlighted and used to improve well planning through a risk assessment and a drilling program using well planning software adapting to the experience highlighted.

1.1 The need for cost effective systems

In recent years, shale oil recovery has experienced extraordinary development, delivering higher production growth than offshore projects. Shale is a very competitive source of production, giving operators the flexibility to alter activity according to oil price fluctuations. With lower development costs and shorter cycle production gains, shale oil recovery projects will be the fastest to recover as soon as oil prices increase.

Deepwater offshore projects in more complex reservoirs may need fewer wells but at high expenditure with possible costs of about $180 million to run a single operation. In order to compete with shale oil recovery, oil majors are scrambling to cut costs.
Chronic delays and ballooning costs is one of the major problems with large projects offshore. According to Bloomberg, around 80 percent of large projects fail to stay on budget schedule. About three-quarters of them have suffered delays, and two-thirds have blown through original expected cost budgets (Nysveen et al., 2015).

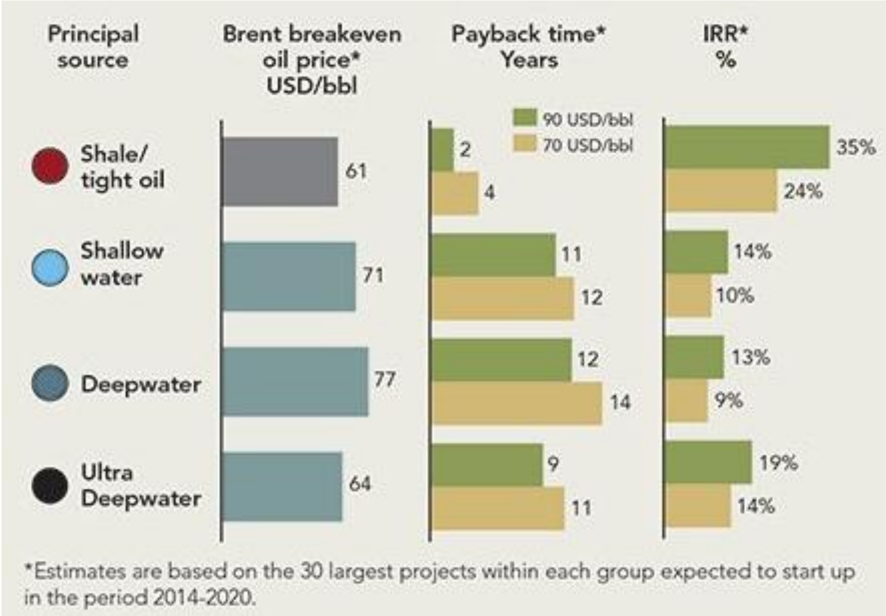

Figure 1: Three economic performance benchmarks: break-even oil prices, payback time, and IRR.

As displayed in figure 1, shale and ultra-deepwater fields have the lowest break-even prices at US$61 and US$64, respectively. In terms of payback years, shale is much more attractive with four years before payback, assuming an oil price of US$70/bbl, compared to 11 years for ultra deepwater.

In order to compete with economically beneficial land wells, the industry is changing progressively. Presently there are trends towards deeper sub-sea wells, and new technology like slim-hole drilling is under development and utilized to help achieve overall lower costs. Therefore, even when progress is made in one area, new challenges will still be encountered, because the limits are always extended. Simultaneously, the resources and amount of information learned is increasing. Although technology is advancing, failures do occur, leading to loss of valuable time. Whenever the process is running smoothly or is failing, valuable experience is gained. An essential way to improve is to learn from failures, therefore experience transfer is important.

The estimation of time required for the drilling, completions and well operation processes is important for the evaluation of performance and the budget process. Since most of the costs involved in well construction are time dependant, understanding the drivers for time usage is important. To receive a measurable return on investment, oil companies want to achieve a reduction in accidents, an improvement in oil and gas recovery and fewer lost days of operation.

The frequently faced problems are often related to borehole stability. Casing landing problem, stuck pipe, hole cleaning problems and cementing problems are often a consequence of borehole stability problems. The aforementioned problems can be difficult to handle, and it is fair to say that issues related to NPT are not fully understood and mitigated.

Weather, wellbore characteristics, equipment failure and other sources of risk amass into NPT which adversely impacts the efficiency and costs of drilling operations. With newer wells planned through deeper and difficult formations, it is imperative to increase the drilling efficiency and cut the costs of drilling operations especially for offshore locations where the high temperature and pressure conditions mean that the window between reservoir pore pressures and fracture gradients can be quite narrow.

1.1.1 Problems with ROP focus for efficient drilling

To drive down operational costs, while continuing to push drilling activities into harsher and more challenging environments, emphasis must be placed on drilling efficiency. In most instances in the industry, discussions related to drilling efficiency have centered on rate of penetration (ROP). ROP must not be equated to drilling efficiency but instead as one of several parameters that influence drilling efficiency (Mensa-Wilmot et al., 2010).

Drilling efficiency is claimed to improve when ROP increases, therefore as a means towards drilling efficiency improvement, ROP enhancing strategies are usually devised and implemented. However, even when an ROP increase has the perceived positive effect on drilling efficiency, the resulting operational costs have not always been desirable.
Critical operational parameters must be identified and analyzed to have the desired operational costs when improving drilling efficiency. As part of the evaluation process, the parameters must be allotted the appropriate levels of importance based on the defined project objectives.

To improve drilling efficiency, the listed parameters should not be analyzed in isolation because they are inter-related. Consequently, maximizing any particular parameter without identifying and addressing the effects on the other parameters, can compromise drilling efficiency (Mensa-Wilmot et al., 2010).

ROP improvement efforts often do not address these concerns, resulting in inconsistent effects on drilling efficiency. Regardless of the drilling program, the parameters - downhole tool life, steering efficiency, ROP, borehole quality etc. are always the same. However the ranking of importance of the different parameters can vary for different projects.

To achieve drilling efficiency, the objective must be geared towards the lowest cost per section and eventually the construction of useable wells. Therefore the sources of NPT must be analyzed in detail. This includes the minimization of drilling related inefficiencies and certain drilling related unplanned events, trips associated with bits, BHAs and down hole tools must also be analyzed. In some instances, based on the time percentage distributions between total well NPT and on-bottom drilling time, drilling efficiency is discounted as an area of focus for cost reduction.

However, an NPT breakdown by function, coupled with a detail review of reaction sequences, usually depict different conclusions. Apart from rig and geological events, several NPT events can be linked to on-bottom drilling time activities and these consequences can be linked to well planning and system design decisions. The use of Well Planning software models and Real-Time Drilling software to predict parameters and then monitor parameters and make adjustments with predictions accordingly are key in mitigating NPT events linked to on-bottom drilling time (Mensa-Wilmot et al., 2010).

1.2 Requirement for Experience capture and transfer

Most operators for deepwater drilling projects have tried to curb capital costs, particularly on drilling expenditure. Several operators have succeeded by focusing on operational improvements, such as reducing NPT, optimizing procurement practices or by improved management performance.

For the average offshore oil and gas operator, drilling and completion projects account for about 40%- 50% of total capital expenditure. For offshore wells, about 70% to 80% of these costs are time related, suggesting that any compression in delivery time will have a direct benefit to improving costs (Brun et al., 2015).

Well delivery process

Improvement levers	Portfolio and rig strategy	Prospect maturation and high-grading	Wells engineering	Logistics and supply chain management	Drilling and completion execution	Hook-up and post-mortem learning	Potentials[1] % of total well cost
Drive learning curves across the well delivery process	▪ Rigs to work on long series of similar jobs ▪ Long range plans with strategic suppliers		▪ Planning teams to specialize on type of jobs		▪ Rig teams work on long series of similar jobs ▪ Minimize rotation of crews		20-25%
Standardize and simplify specifications, designs and processes		▪ "Perfect well" planning and estimation approach ▪ Use of std wells as basis for 80% of portfolio	▪ Defined std well and options, based on drivers of costs				10-15%
Lean drilling execution					▪ Lean execution principles to drive down NPT ▪ Drive actively operational efficiency	▪ Active planning and debottle-necking of hook-up towards asset	5-10%
Procurement and supply chain optimization	▪ Contracts incentivize real productivity improvements ▪ Use down-turn to reduce unit costs			▪ Capitalize on std specs to drive down unit costs of procured services and equipments			10-15%
Rigorous performance management			▪ Active monitoring and target setting for engineering productivity		▪ Execution daily monitored against 'Perfect well'		5-10%
	10-15%	5-10%	5-10%	10-15%	20-25%	3-5%	50%

Figure 2: McKinsey drilling toolbox: Drilling spend improvement levers across the well delivery process, potentials and example improvements.

As seen in figure 2, the most fundamental cost reduction driver is to drive learning curves rigorous portfolio and planning optimization at all levels to prevent overwork. Optimizing this lever can achieve up to 20%-25% reduction in the average cost per well.

A priority for many suppliers is to achieve better transparency and predictability in drilling activities. Transparency is critical. It allows all parties to improve planning and develop their services to be more streamlined and efficient (Brun et al., 2015).

Wells and their designs often depend on each other and plans tend to change based on the latest insights and developments. Therefore, drilling teams are often unable to plan in advance, resulting in suboptimal logistics and rig allocation.

In order to stabilize the drilling plan and plan ahead, all departments involved need to align and commit to predetermined results. Examples indicate that drilling teams repeating very similar activities on 10 or more wells become 30%-40% more efficient over just a few months than teams executing these activities for the first time or infrequently. Similar wells must be clustered in order to create repetitive jobs for drilling crews. Standardizing on well types reduces the amount of learning that a team has to do across a number of wells. Specialized crews should be able to rise up to the ideal working speed quicker, thus at a lower resultant cost.

However, previous studies have shown that drilling costs can vary for wells drilled in very similar geologic environments with identical technical objectives. There are two probable causes for this variability:

- Differences in the specific geological formations encountered while drilling
- Differences in controllable drilling parameters

The reason for such high variability in drilling performance can be explained by looking at a drilling operation as an imperfect application of experience. Controllable variability in drilling performance is economically significant and that one possible opportunity for realizing this benefit is to improve the way the industry cooperates to capture and disseminate successful practices (Brett et al., 2000).

To obtain a high rate of learning requires an organization must learn and capture experience and technology in such a way that it can be rapidly transferred to other operational personnel. This implies central organizational personnel. Drilling teams linked by high level communications, using state-of-the-art technology consistently shows a higher level of performance.

2 Theory

2.1 Experience Transfer

Having experience is the capacity for effective actions or decision-making in the context of organizational activity. A lack of knowledge and experience learned would decrease this vital capacity and help undermine organizational effectiveness and performance. The goal of transferring experience is to:

- Identify key areas and personnel where potential knowledge loss is impending
- Assess how crucial the lack of experience will be
- Develop a system to ensure that critical experience is captured and transferred

Experience Transfer has always existed in one form or another through on-the-job discussions with peers, professional training and mentoring programs. Advances in technology have played a vital role in Experience Transfer through the creation of expert systems, and knowledge data bases.

‘Knowledge’ is richer and more meaningful than information. Knowledge is what is known and is gained through experience, reasoning, intuition, and learning. Because knowledge is intuitive, it is difficult to structure making it hard to capture on machines and can be challenging to transfer effectively. Knowledge is expanded when experience is shared.

A clear distinction must be made between the two types of knowledge, tacit and explicit knowledge. Tacit knowledge is often subconscious and internalized in the forms of experience and insight, which can be context dependant based on the individual and difficult to express (Saadatakhtar et al., 2013). Explicit knowledge on the other hand is conscious knowledge that the individual holds consciously in mental focus, and can express this knowledge to others easily.

- **Tacit knowledge** is often difficult to access. People are not aware of the knowledge they possess or how valuable it may be to others. Tacit knowledge is considered more valuable because it provides context for people, places, ideas, and experiences. Effective transfer of tacit knowledge generally requires extensive personal contact and trust.

- **Explicit knowledge** is relatively easy to capture and store in databases and documents. It is shared with a high degree of accuracy. It may be either structured or unstructured:
    - **Structured** - Individual elements are organized in a particular way for future retrieval. It includes documents, databases, and spreadsheets.
    - **Unstructured** - The information is not referenced for retrieval. Examples include e-mail messages, images, training courses, and audio and video selections.

2.1.1 Benefits of an Experience Transfer Program

Experience Transfer programs prevent critical knowledge loss by focusing on key areas. Some of the immediate benefits of Experience Transfer programs are:

- Providing reusable documentation of the knowledge required for certain positions.
- Immediate learning and knowledge transfer when carried out by individuals who can either use the transferred knowledge themselves or have responsibility for hiring, training, or managing people within an organizational unit.
- Reducing the impact of employee departure.
- Integrating training, job and organization redesign, process improvements and other responses.
- Aid in succession planning.
- Preventing the loss of knowledge held only in employees' heads when they leave the organization or retire.
- Enhancing career development.

2.2 Importance of Experience Transfer in Drilling Operations

Efficient construction of wells through potential trouble zones depends on the accuracy of the well data analysis. Often data and learning experience from a previous well construction attempt within a project are ignored and the well is drilled with the same mindset that was used by the same drilling and planning crew on a previous failed attempt, expecting different results. Even though this approach is illogical, it has too often been the normal practice in many offshore projects as proven by the amount of money spent consistently on combating known and expected drilling trouble zones.

Habitual unwillingness to try varied design philosophies, drilling practices or the reluctance to implement new and underutilized technology, maintains the difficulties faced by operators when drilling through complicated zones. Even with the current state of the art technologies available, NPT remains as a consistent issue with deep wells and the tired cliché of ‘that is the way it has always been done’, no longer should pass as an excuse.

To compete in tough economic times, a 10%-20% contingency fund within a well’s AFE should not be rationalized as normal practice. Instead there should be an increased focus on risk assessment with an open-minded drilling philosophy involving technologies capable of mitigating difficult drilling conditions. To overcome the cost and risk of deep sea drilling, operators must coalesce with the service industry as partners and utilize the experience of the service industry from other fields and operators from all around the world, to push for cost affordable deep sea drilling and completion technologies. Under current economic constraints, the industry demands that well designs must improve and hazards must be minimized. The industry should not be guilty of repeating the same process and hoping for different results.

A significant percentage of the operating workforce is nearing retirement age over the coming years. The knowledge gap created by ‘The Great Crew Change’ that exists in most companies has been well documented and discussed. Most employees in the oil and gas industry are responsible for developing a career spanning 35-40 years and have acquired a tremendous amount of knowledge about how things work and how to make the right decisions when problems arise (McCormack et al., 2010).

Losing this expertise and experience could significantly reduce efficiency and cause significant disruptions in services and performance. In addition, faster turnover among younger employees and more competitive recruiting and compensation packages add significantly to the mounting concern about the ability to sustain acceptable levels of performance. The immediate challenge today is transmitting the soft and hard skills necessary to quickly bridge the gaps between new and existing personnel.

2.2.1 Positive Experience

'Positive Experience' is when a drilling procedure is successful and operators can learn from the positive aspects of the procedure to improve general drilling practise and to note whether the procedures from the positive experience can be used in a similar scenario to challenge theoretical parameters and improve performance. As an example, positive experience is gained in a scenario where ECD exceeds theoretical fracture gradient without the well going on losses or showing signs of unusual drilling parameters when drilling through rumored depleted zones. The operator can learn from the positive aspects of this experience and note that the theoretical fracture gradient is too conservative, and since no losses were observed the zones may not be depleted as initially perceived. The positive experience will help develop planning and operations to drill with improved efficiency and through zones that might have been avoided without the experience gained.

Positive experience gained can also be the affirmation of a good drilling practice procedure having visible positive effects on the drilling operations, therefore developing and improving operations for forthcoming sections within the well or zone. As an example, pumping or lubricating out of hole in areas of potentially weaker formation, as a sensitive method. Despite this method being more time consuming, it is observed that it has in fact led to net time savings, since this practice results in a bore hole with fewer occurrences of pack offs or tight spots which are time consuming to deal with and could result in loss of the section or even the well.

2.2.2 Negative Experience

'Negative Experience' holds for errors made in drilling operations, bad drilling practices and procedures leading directly towards NPT. Such events have a negative impact on the project and should be avoided in future projects. Negative experience is important because analyzing the events can help point towards direct sources of NPT or other hazards that might be impending within the well. Negative experiences can stem from failures under a range of segments including the formation, well design, equipment, operational activities and well bore cleaning.

Drawing out the negative experiences under these segments to help avoid these events can develop improved planning and procedures for the forthcoming section or well. An improved well plan and risk assessment taking into consideration negative experiences is essential for drilling a well with the highest efficiency and avoiding NPT related events.
While NPT is clearly the consequence of negative experience, it holds the line between negative and positive experience. The goal of applying all experience learned is to improve designs (simpler and slimmer holes), well planning and lower costs overall by reducing NPT. Therefore it is important to understand NPT and its sources.

2.3 Non Productive Time (NPT)

Non Productive Time (NPT) may be defined as an unplanned event that prolongs the operations schedule. Although delays are expected in drilling operations, the cumulative effect of NPT over a program of drilling projects may adversely influence the number of wells that can be drilled within a set time period. NPT can have a serious effect on the economic viability of a project, as well as resulting in destructive effects on the environment.

Sources of NPT include down hole tool failures, rig repairs, waiting on weather, pulling of dulled bits, running and cementing casings, and wireline logging. Figure 3 shows a breakdown of estimated costs from sources of NPT.

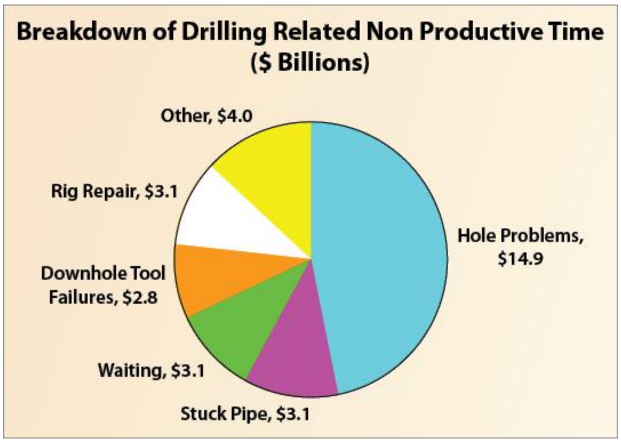

Figure 3: Breakdown of Drilling related NPT (Dodson, 2009).

NPT Analysis in Gulf of Mexico deepwater operations, exclusive of weather using data supplied by James K. Dodson Company, focuses on the total NPT of key drilling hazards created by wellbore instability – stuck pipe, well control and fluid loss. Figure 4 shows how Well Bore instability accounts for the majority – 41% of total NPT, excluding waiting on weather for subsalt wells with depths greater than 915m.

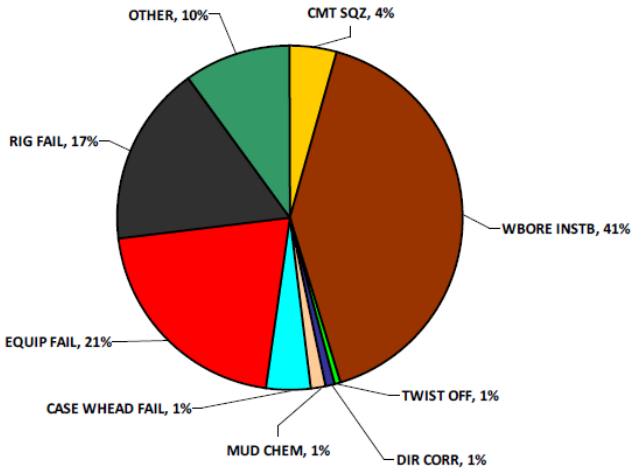

Figure 4: Subsalt Wellbore instability as a percentage of total non weather NPT (Dodson, 2009).

NPT may be experienced during each stage of drilling operations but one of the main risks and causes of NPT are vibrations that occur when the drillstring interacts with the rock formations as drilling progresses. Other frequent sources of NPT are listed in table 1. It should be noted that particular sources of risk may overcome the significance of others in different geographical regions of oil and gas reserves. Therefore approaches for mitigating NPT risks depend on the prevalent sources.

Stuck Pipe	Twist off	Kick	Directional correction
Lost Circulation	Sloughing shale	Weather delay	Cement Squeeze
Wellbore instability	Equipment failure	Rig failure	Mud/chemical
Shallow gas flow	Shallow water flow	Vibration	Casing or wellhead failure

Tabel 1: Sources of NPT (Amadi-Echendu et al., 2012).

The cause of most drilling problems encountered in deep water wells is related to managing the narrow drilling or operating window. This drilling margin represents the boundary between the lowest ECD required for a safe operation and the highest ECD that can be tolerated to avoid fracturing the casing shoe of the prior casing string.
The reason for decreasing well performance as the complexity level increases is related to the water depth and its effect on the pore pressure and fracture gradient relationship and resultant operating margins (Kotow et al., 2009). The drilling margin tends to decrease as water depth increases.

Narrow drillings margin operations are not limited to any particular environment. Failure to recognize, or misinterpreting the dynamics of the drilling margin can result in fluid losses and sometimes lead to disastrous events.

2.3.1 Ballooning

'Ballooning' is a consequence of high ECD. Resultant flowback can often be confused with influx due to a pore pressure greater than mud balance. This is often further complicated by gas entrained in shale , common especially in mottled shale, with the operator 'weighting up' to counter the shale gas again , further complicating ballooning. Arbitrarily increasing mud weight in the presence of shale gas alone can result in fracturing the formation below or at the shoe.
Failure to recognize ballooning versus well control is a common mistake made in drilling operations. It is one of the leading causes of unnecessarily expending casing strings in narrow margin drilling operations (York et al., 2009)

2.3.2 Fluid Loss

Fluid losses have the potential to result in wellbore failure or serious well-control events. The prime cause of fluid loss is exceeding the outer boundary of the drilling margin. This could either be the result of ballooning or if in porous formations, the result of applying unnecessarily high mud weight resulting in high ECDs. Maintaining an ECD balance that is low enough to ensure fluid volume integrity, while high enough to exceed the lower boundary necessary for wellbore integrity, is critical (York et al., 2009).

2.3.3 Stuck Pipe

Stuck Pipe is another drilling hazard that can be associated with both ballooning and fluid losses. In general, stuck pipe should be avoidable if the drilling margins are honored , with the exception of the following primary causes:

- Differential Sticking
- Key seating and hole geometry
- Pack-off
- Reactive formations

Cuttings build up, permeable sections, collapsed casing etc. are some of the other secondary causes of stuck pipe in drilling operations. Generally, the best practices to avoid the aforementioned problems of ballooning, fluid losses and stuck pipe are to recognize the conditions within the drilling margins and react accordingly.

The drilling hazards discussed are not meant to comprise an exhaustive list, however examples of drilling hazards that are sources of NPT. As the rest of the report will discuss, these sources can be recognized and either avoided or mitigated effectively through well planning, real time drilling software and experience transfer (York et al., 2009)

2.4 Well Planning software

Well planning software, use of down hole motors and turbines, and other techniques to drill horizontal wells help to reduce NPT and increase the recovery factor. Simultaneously, some of the challenges faced are higher fracture or pore pressure. The higher inclination on these sort of wells in ultra-deep waters originates a narrow drilling window with an overburden pressure, where a very narrow merging between pore and fracture pressure profile can be very risky.

In order to plan, have better control and carry out drilling operations in complex wells, well planning software and numerical models are crucial to handle a large amount of data and plan the wells efficiently. The programs take out much of the labour of planning, saving a lot of time to approach a better understanding for the "Well Program" and "Drilling String program" through simulations.

Well Planning software like ‘WellPlan™’ allows new wells to be designed efficiently. Well designs are improved to prevent stuck pipe and BHA failures, reduce drilling problems and drill efficiently (Landmark, n.d.). The simulations carried out through WellPlan™, allows the user to have better estimations and reduce the uncertainties before to run a drilling operation in place, to recreate a simulation for an optimal well design at any stage of the drilling process. Well planning softwares create faster and better quality engineering workflows from planning to production. Rig site data collection and reporting system enables engineers to directly create a case and populate it with pertinent field and rig data for faster decision making and engineering studies.

WellPlan™ is an integrated, modular set of applications used by drilling engineers to develop optimal well designs. The Bottom Hole Assembly module models drilling performance of rotary steerable directional BHA’s utilizing finite element analysis technology. Drilling tendencies of the assembly can be predicted and bent sub assemblies are also supported.
The software’s Torque and Drag module provides a detailed analysis of the torque and drag forces affecting a drill string during various modes of operations. Drill string design can be optimized to minimize torque and drag forces and reduce the likelihood of stuck pipe and drill string failure.

The Hydraulics module allows the drilling engineer to design the optimum bit and drilling fluid combination for maximum performance. Hydraulics provides a complete analysis of the circulation system, selects the best jet sizes for optimum ROP, and allows study of ECD’s with regard to pore pressure and fracture problems. Surge/swab analysis can also be undertaken, as well as hole cleaning (Landmark, n.d.).

3 Field Data Analysis

3.1 Case Study – NTNU Field

A complete data set of a field with all types of experiences from all wells drilled, from exploration to fully developed, was offered by an operating company that will remain classified. In this case study, the field will be referred to as the NTNU field and since the details of the field are classified, the names of the wells have been changed and the drilling data will not be available in the appendix. The well data will not be required to understand the events discussed and the impact on NPT related factors.

The analysis of the data and experiences is summarized in short below in this chapter. All fields would have some specific experiences but many are relative for other fields. Therefore, the experience analysis of this field has been used to develop the drilling program for the sidetrack discussed in chapter XX. The NTNU field has a complex structural history with the presence of three different reservoirs, plus internal heterogeneities and isolated pressure compartments. The lack of geotechnical data gave little information about the original stress state of the field; therefore a uniform depletion factor of 0.4 was applied to the entire field which did not adequately represent the variability of pressure regimes across the field.
A review of the historical well observations from the NTNU field was conducted to analyze and draw out the implications. The review of historical data has focused on the collation of all available relevant data, summarizing well experiences and events in all of the production wells.
The analysis of well data in this field will discuss experiences and the impact on:

- Formation Stability
- Depletion
- Drilling Practices
- Low Energy Drilling
- Hole Cleaning
- Data Acquisition
- LCM Strategy
- Well Design

3.1.1 Formation Stability

The primary purpose of the wellbore stability plot is to reflect the drillability of the well in successive sections and is an important element when discussing the operational window. Regardless of formation, further study shows that the shale bearing formations are more stable than the theoretical collapse gradients would suggest, despite a variety of mud weight and well inclinations. Many of the problems experienced can be related to poor drilling practice and well design or a combination of both.

In well 1A, the entire formation was drilled during the 12.25" section with a MW of 1.56SG. However the 9 5/8" casing shoe had been set 9m shallower than TD. Although the rat hole had been cemented, assuming that the cement job could have been poor, parts of the base formation interval could have seen low mud weight (1.50 SG) that was used in the following 8.5" section. Yet no collapse indications in the form of cavings or enlarged holes had been observed. During the 8.5" section of well 1AB, the theoretical collapse gradient for the formation was significantly challenged as the collapse curve indicated values above the static mud weight pressure. In this case, the entire formation was drilled with a mud weight of 1.50 SG and in inclination of 70^o. Drilling throughout the formation was controlled and all mud and drilling parameters kept within specification.

3.1.1.1 Hole inclination

A guideline that dictates a maximum angle of 20^o relative to stratigraphy be maintained while drilling the formation-1 interval. However no evidence was found to support this guideline. Hole inclination should not be regarded as a limiting factor as almost every angle possible has been drilled in the NTNU field wells either by accident or design.

Ultra high inclinations or layer parallel drilling in shale rich formations should be avoided as incidents have been observed associated with this. However the use of high inclination drilling within these formations is perfectly acceptable provided a relative angle to bedding is maintained. Removing the angle limitation to reach the lower formation-1 gives more freedom in well design, leading to avoidance of unnecessary drill length and avoiding the further possibility of stuck pipe. It is recommended that the standard field practice of running density image logs is retained, as this provides an overview of the stratigraphic angle during drilling, allowing corrections to be made for any unsuitable well bore angle. This is both time and cost effective as it can aid in the avoidance of pack offs and at worse stuck pipe and loss of hole.

3.1.1.2 Faulting

Several issues associated with fault intersection and problems related to collapse have been wrongly interpreted as examples of inherent formation instability rather than as a normal result of the fracturing of the formation. Fault related fracturing will result in weakness within the host rock. If the wellbore intersects a fault in an interval with high collapse peak, then this will further weaken the formation. A higher number of incidents are reported when comparing faults through a more competent lithology like sand with a weaker one like shale. Problems are less evident with shale-shale contact.

The angle of attack to the fault can play an important role where low relative angles of attack to faults result in longer exposure time in the fault zone leading to a higher risk of collapse. Experience in well 5A observed that a combination of parallel drilling and local faulting in the section resulted in pack offs observed after drilling the section while RIH after the bit trip. Therefore well design is a factor that must account for this risk.

Experience from the 4A well shows that losses occurred at the base of the formation interface and the fault zones. Use of cold mud which can fracture the reservoir can also be attributed to the losses as seen in the experience of well 9A, where formation strength was reduced due to cooling and fracturing by gas injection was not recognized as a risk factor.

There is a possibility that drilling through a fractured zone containing shale in the formation, would have corresponded to a bed boundary loss. Losses in fracture zones should not be assumed to heal by themselves. The use of LCM was instrumental in controlling some of the loss events at the fault zones.

3.1.1.3 Mud Weight

Experiences from the IPT wells are very relevant as they provide good examples of how stable the formation-1 can be at high inclinations and lower mud weights (1.25-1.28 SG). IPT field is lithologically very similar to the NTNU field, the observations are directly applicable. This experience could provide a guide for future mud weight strategies for reservoir drilling on the NTNU field in general. The mud weights used on the IPT field are considerably lower than those used on NTNU and despite this, the formation-1 remained stable for long periods of time after drilling, even at high inclinations. Analyzing the mud weights and experiences from the IPT field opens the drilling window of the NTNU field and the ability to drill previously unattainable targets.

3.1.1.4 Drilling Practice

Drilling Practices have a large role in the success of any drilling operation. Observed factors in the NTNU field that have resulted in problems include:

- Poorly chosen circulation strategies either when cleaning the hole or circulating.
- Aggressive and poorly executed wiper trips
- Poorly planned disconnection strategies-without weighing up.
- Back reaming of intervals which are sensitive to this activity such as transition boundaries, fault zones especially when combined with low relative angle to stratigraphy.
- Poor Well design and poor stratigraphical control leading to the drilling of numerous layer parallel intervals in shaly formations

Some positive experiences were observed in pumping or lubricating out of hole. This is generally a more sensitive method in areas of potentially weaker formation. Despite this method being more time consuming, it is observed that it has in fact led to net time savings, since this practice results in a bore hole with fewer occurrences of pack offs or tight spots which are time consuming to deal with and could result in loss of the section or even the well.

3.1.2 Depletion

Assumed depletion effects were the cause of some well incidents. These events can be attributed to a more complex set of events unrelated to primary depletion effects.

- Several of the loss events on the NTNU field can be attributed to poor risk management. Potential for encountering depleted zones was not sufficiently identified prior to drilling
- Poor well design in general has led to an increase in risk factors
- Failure to address existing open well completions
- Losses caused by poor drilling practices – use of cold mud, excessive and erratic ROP that resulted in excessive cuttings production
- losses prior to or during cementing of the liner

An essential observation with a positive impact on NTNU's drilling window is that in several wells the theoretical fracture gradient based on the 2D theoretical model has been exceeded by the ECD without the well going on losses.

Drilling reports show that while observing time based data, no sign of unusual drilling parameters even when ECD exceeded fracture gradient. The theoretical fracture gradient was too conservative and the data studies show that in many cases the theoretical fracture gradient can be challenged.

Several examples of losses at bed boundaries are observed from the well data. The key aspect is the ability of the formation to develop a reasonable filter cake. Poor development of the filter cake can permit communication between the borehole and pore network, which could result in fracture initiation at lower pressures. It is probable that fracture initiation does not occur within depleted sands themselves, but rather in connection with other lithologies, or more importantly in the boundaries between lithologies.
Likely scenarios in the NTNU field for depleted sands would be low, but very uncertain minimal horizontal stresses due to depletion; but countered by the possibility for relatively high fracture initiation pressures due to development of a good filter cake.
For other lithologies, non predictable fracture initiation pressures due to lack of filtercake, weaknesses in the borehole wall and possible depletion. Collapse limits are variable due to different mechanisms in different lithologies.

This non uniform behavior can explain the variances between the direct pressure measurements and the models. This shows that the geomechanical models should not be used to provide precise or explicit stress pathways, but rather used to give a qualitative input about the effects the reservoir geometry (faults) can have on the stress pathway.

Observations were made in well data, where the ECD exceeded the theoretical fracture gradient by 14 points in some formations. In addition it has also been observed that the fracture gradient has been exceeded for a considerable length of time before breakdown has occurred and the well went on losses.

3.1.3 Drilling Practices

Analysis of the well data shows that the general drilling practice during operations significantly accounts for most of the pressure losses observed and well incidents involving NPT.

Experience for well 12A shows that ROP was increased to improve drilling efficiency, however the increased ROP was not justified by the increase in ECD and circulation trends led to an increased circulation time. Excessive circulation led to hole problems later in the section.

Use of cold mud can be a contributory factor to loss event since it resulted in the thermal shocking of the formation. From the experience of well 9A, it is learnt that the well objective was not achieved due to lack of sufficient formation strength to drill the well required to TD. This was the result of not identifying the risk of reduced formation strength due to injection cooling. An initial FIT and subsequent data analysis would have been beneficial to establish the formation strength in the area around the open perforations.

Most of the pack off incidents was due to human error and poor drilling practices. In well 4A, the pack off close to the casing shoe was most likely related to solid sagging during the 1 week disconnection. Observation of mechanical cavings was due to the drill string violently colliding with borehole wall prior to disconnection. These events may have been avoided by not starting the section when poor weather was forecast.

Analyzing the drilling data for well 5C, it is observed that erratic high ECD and SPP recorded suggested pack off tendencies. However two periods of stationary circulation of 1 hour and 90mins respectively were also conducted in this section, stressing the borehole walls further. Also analysis of the trip out of hole after drilling the section shows that the tripping speed was far too high and the formation was swabbed down to a pressure close to the shear failure pressure of the formation. The section was lost due to formation collapse after tripping out of the hole. Analyzing time based data for the trip out of hole after reaching TD. This showed that the tripping speed was far too high with the result that the formation was swabbed down to pressures close to the shear failure of the formation by 1.4SG.

Some cases of positive experience are also found when analyzing the drilling data for some of the wells where ‘Low Energy Drilling’ principles were applied.

When tripping OOH after penetrating the formation-1 (8.5” section), the string was pumped put of hole with 500lpm for hole stability purposes in the transition area between the formation-1 and formation-2. This practice resulted in a stable wellbore. When at TD, circulating the hole clean 4-5 times and increasing the mud weight to 1.65 SG EMW prior to pumping out of hole, although time consuming, resulted in a clean hole.

In well 5A, when running the 7” production liner after drilling was completed, some excess drag and pack off tendencies were observed. The excess drag was through the same section in the formation where the parent wellbore was observed to have collapsed. The restriction was passed by rotation, circulation and moderate application of weight. (20tons)

In well 8A, lubricating OOH from 2400m to shoe in higher pressure intervals, LCM was added to ensure full circulation before entering possible depleted reservoir and ROP restricted to 10m/hr.

At TD, the hole was circulated clean while pulling up to avoid washing out coal in the formation. POOH was restricted due to danger of surge and swab.

From the drilling experience learned by analyzing the well data on the NTNU field, measures can be taken to avoid NPT that results due to poor drilling practice:

- Use of 'weak rock drilling' parameters while drilling through depleted formations and shale rich formations. Suitable flow rates, avoid cycling mud pumps, controlling of repeat surveys, avoidance of logging while reaming in areas of potential instability
- High focus on ECD control to ensure stable ECD parameters in all phase of the drilling operation
- High focus on mud conditioning including specification and avoidance of thermal shocking of formation due to cold mud. Mud sagging fir example during a disconnect and its potential for pack off generation
- Correct calculation of recommended drilling ROP and pulling speeds
- Correct calculation of liner running speeds
- Lubricating out of hole when hole stability problems have been observed/suspected or in the area of formation boundaries. In general this is a good operational practice.
- Avoidance of stationary or static circulation in shale bearing intervals
- Balance flow rates between the requirement for good hole cleaning and the risk of formation damage
- Low flow rates while taking pressure points

3.1.4 Hole Cleaning

Poor hole cleaning in some of the earlier wells has led to problems such as tight spots and pack offs, resulting in NPT or abandonment of the well.

- Higher flow rates have resulted in damage to formations with resultant washouts
- High ROP's combined with high flow rates resulted in poor well cleaning and high ECDs
- Drilling during winter can present challenges for hole cleaning
- In long 12.25 and 8.5" sections characterized by high inclinations, well design itself can pose challenges for hole cleaning

Real time monitoring of well cleaning can in many ways offset many of the potential problems which result from the buildup of excessive cuttings bed. Fewer problems were encountered where drilling charts of ECD v ROP were closely monitored.

Analyzing the well data for well 4A, it can be observed that high ROP in the12.25" section due to heave effects resulted in overpull observations and mechanical stuck due to overloading the hole with cuttings. Experience from other wells show that high ROPs at TD may have resulted in poor hole cleaning and thus been partly responsible for some of the issues seen while POOH. For well 5A at TD, the hole was circulated clean with 4-5 B/U and the mud weight was raised to 1.65SG EMW prior to pumping out of hole. Although time consuming, this practice resulted in a clean hole.

The positive experience for well 5A is not applicable for well 13A where each stand was washed down and the logging carried out whilst pulling up, this was under taken to ensure the hole was clean before logging and getting stuck. However circulating and washing within shaly intervals is not recommended practice due to the danger of washing out of hole.

From the drilling experience learned by analyzing the well data, measures can be taken to avoid incidents that are the result of poor hole cleaning:

- Optimum ROP for a formation must be decided based on the geological characteristics of the formation to be drilled, the well geometry and previous ROP experiences, this means that optimum ROP should be set from well to well and will vary dependant on the hole cleaning needs of the well.
- Important that when low flow drilling is needed, key performance indicators are not set with regards to high ROP. The optimal max ROP for the section will be decided by the actual ECD contribution seen in the operation phase and not by simulations.
- Hole cleaning plots should also be investigated and challenged where possible. The practical lower limit for hole cleaning will most probably be the limit set on the MWD to turn on/off at low flow rates and it should be challenged. This might be worth investigating in the future if extremely low flowrates are required to minimize risk of not fracturing the formation.

3.1.5 Data Acquisition

The well data study clearly demonstrates the value of a robust LWD data acquisition program as well as the consequences of the lack of such data.
In recent times, the acquisition of formation pressure as soon as possible after entering the reservoir and along the wellbore has been prioritized. Image data is regarded as a positive investment since accurate structural knowledge while drilling has resulted in better and more stable wellbores with a higher chance for successful completion and lower chance of a geological or even technical sidetrack. Many of the earlier wells suffered lost time, loss of section and loss of productivity due to poor stratigraphic and structural control.

Leak off Tests should be a standard operating procedure unless there are specific operational reasons against. Formation integrity tests should be designed to be representative for the upcoming section. This will give a better understanding of the upper border of the drilling window regarding the fracture and least horizontal stress (S_{Hmin}). Poor data acquisition will lead to more sidetracks; lack of calibration data will not open the drilling window.

3.1.6 Well Geometry and Design

Sinuous wells are visibly attractive because of the potential for draining long reservoir sections with multiple penetrations, but they have significant issues:

- Require good stratigraphic and structural control as well as the ability to respond to unexpected events.

- Many sinuous wells have suffered from poor structural understanding, resulting in several side tracks due to exiting the reservoir unexpectedly and in some cases, hole collapse due to inadvertently drilling layer parallel in weak shale.

- Several S and W shaped wells become ‘out of phase’ with the target reservoir zones due to unexpected faulting or poor statigraphic control resulting in tortuous well paths in order to steer back to a productive reservoir. This resulted in reduced production since intervals of non productive reservoir are interspersed with the production interval.

Drilling in sinuous wells has in general resulted in considerable non productive time due to hole cleaning issues, tight spots etc. which can be related to the well geometry. These issues are not restricted to the drilling phase but extended into completion and production operations as well as witnessed by the documented problems when running casings. Poor cement jobs and even failure to clean up the wells properly, as well as the inability to carry out later interventions have resulted from these wells.

There is a clear correlation between length of time spent in a heavily depleted or weak formation and the probability of encountering problems. When a relatively long 12.25" interval was drilled in a heavily depleted formation, problems were experienced when pipe became stationary and dynamically stuck, resulting in the loss of the section.

Sidetracked well 18A set in formation-1 after a significant interval of this formation had been drilled at less than ideal relative angles for this type of formation. This resulted in loss of the first well and problems in the side track.

Simple low angle tangent wells that target the more isolated remaining oil pockets and the deeper formations has resulted in cheaper and more targeted well solutions with a faster turnaround time. Multilateral well designs are a better alternative than a single well concept which would attempt to penetrate both segments and have a higher uncertainty and risk profile, and consequently lower chance of success.

Experience from well 6A illustrates an 8.5" section designed well path to penetrate two different fault blocks in a U shaped design. The planned inclination at TD was 142.5deg and had a planned dogleg of 4deg over 1000m. This ambitious design would involve very strict steering in a shale rich formation. The inability to steer correctly in shaly intervals resulted in several trips and NPT.

From the drilling experience learned by analyzing the well data, some measures can be taken to avoid problems in the NTNU field related to poor well design:

- Simplified well geometries have been demonstrated to achieve the same reserve profile as more complicated sinuous wells.

- Introducing a 6” section into the reservoir to tackle depleted formations and give a larger flexibility on the well design without losing production.
- Cementing in depleted reservoirs is challenging and in some cases it is not possible to guarantee a good cement job for the 7” or 4.5” liner. In these cases, swell packers should be evaluated to be run instead of or together with the planned cement job.

3.1.7 Mud Weight Management

When drilling in depleted reservoirs, the main focus will be to keep the mud weight as low as possible and at the same time high enough to keep the formations stable.
To be able to design wells with the lowest possible MW, we must have a strategy to challenge the collapse peaks in both formations. This can be done by gradually challenging and lowering the MW towards the formations peaks. This should be done in wells where the MW can be increased to a known ‘safe’ value, if the new low MW proves to be insufficient to hold the formations back. With this approach the project will not risk losing the well objective and at the same time achieve valuable formation knowledge needed to be able to drill through narrower drilling windows in the future.

If the inclination is lowered enough to maintain the maximum collapse peak equal to the pore pressure curve, a drilling window will be achieved that allows for the use of the lowest MW possible. However by limiting the inclination through these trouble zones, well placement in the reservoir will normally suffer.

Studying the well experience, it has been observed that these collapse peaks can and have been challenged on the NTNU field as there are frequent examples of trouble free drilling at high inclination through such spikes.
All of NTNU field’s experiences indicate that WBM is problematic in the deeper sections (12.25”) both due to problems with bit balling and NPT (low ROP, excessive tripping and poorer WOB control). This is unfortunate as logistically WBM would be a preferred option.
In well 14A, circulation was lost after dumping 1.90SG mud in the 18 5/8” casing when preparing to disconnect due to bad weather forecast. Dumping excessively weighted mud prior to a disconnect should be avoided. Strategy for weighing up mud prior to disconnect should have been in place.

3.1.8 ECD Control

When considering well design, the ECD is a focus point when trying to maximize the drilling window. Previously there was little focus on optimization of ECD in the reservoir section, but realization of its importance in increasing the drilling window in depleted reservoirs has led to optimization in recent wells. Well 12A Experienced higher than expected ECD due to well design and length of the well, resulting in extra circulation time to reduce ECD.

In well 5AB, high ECD was recorded due to poor hole cleaning. Although flow rate was high, high ROP negated this in terms of well cleaning.

It is important that when low flow drilling is needed, key performance indicators are not set with regards to high ROP's. The max ROP for the section will be decided by the ECD contribution seen in the operation phase and not by simulations

3.1.9 Uncertainty and Risk

The observations of the historical data study clearly demonstrate that the determination of risk for an individual well project will require a thorough review of relevant well experiences with an assessment of the operational planning risks.

Summarized Well experiences can be a useful tool to increase predictive accuracy level in well planning. However regardless of experiences there will still be considerable uncertainty which must be fairly communicated in the process. The risk of human error can never be ruled out. Observations from this study have highlighted the importance of good communication between all involved parties in the well planning and operational phases.
The effect and value of the development of a correct pore pressure measurement strategy on risk and uncertainty mitigation can be seen. Formation pressure measurement while drilling improves both risk handling capabilities in the operational phase and as such is cost effective since lost time or even well control events can be potentially avoided.
Poor risk management in terms of failure to identify significant risks in the planning stage is probably the leading cause of NPT in this field. Applying a good risk management strategy will result in economic and efficiency savings.

3.2 NTNU field experience chart

The analysis of historical drilling data conducted is effective to identify the success and failure criteria for future drilling on the NTNU field, and understanding the development of the operational window. Many of the problems originally attributed to depletion actually resulted from poor drilling practices and poor well design. Three areas must be addressed to reduce NPT related to drilling operations:

Planning: Using data available to schedule activities and build contingencies based on known risks and uncertainty.

Real Time Surveillance: Using data and communications technologies to monitor activities and make corrections that optimize performance.

Experience transfer management: capturing information from planning and operations, securing the appropriate software products and sharing them throughout the organization.

The experience learned from the past well data on the field can be arranged into an 'Experience Chart' to help with planning and operations by understanding the risks involved for the particular field. The experience is divided between 'Formation', 'Operational', 'Wellbore' and 'Equipment'. The chart will draw out the actions under each category leading to NPT related issues that are highlighted within the red field as displayed on the chart. Understanding the experience chart will help to prepare a better risk management strategy and improve well planning altogether to mitigate most of the NPT related issues that have been experienced on the NTNU field.

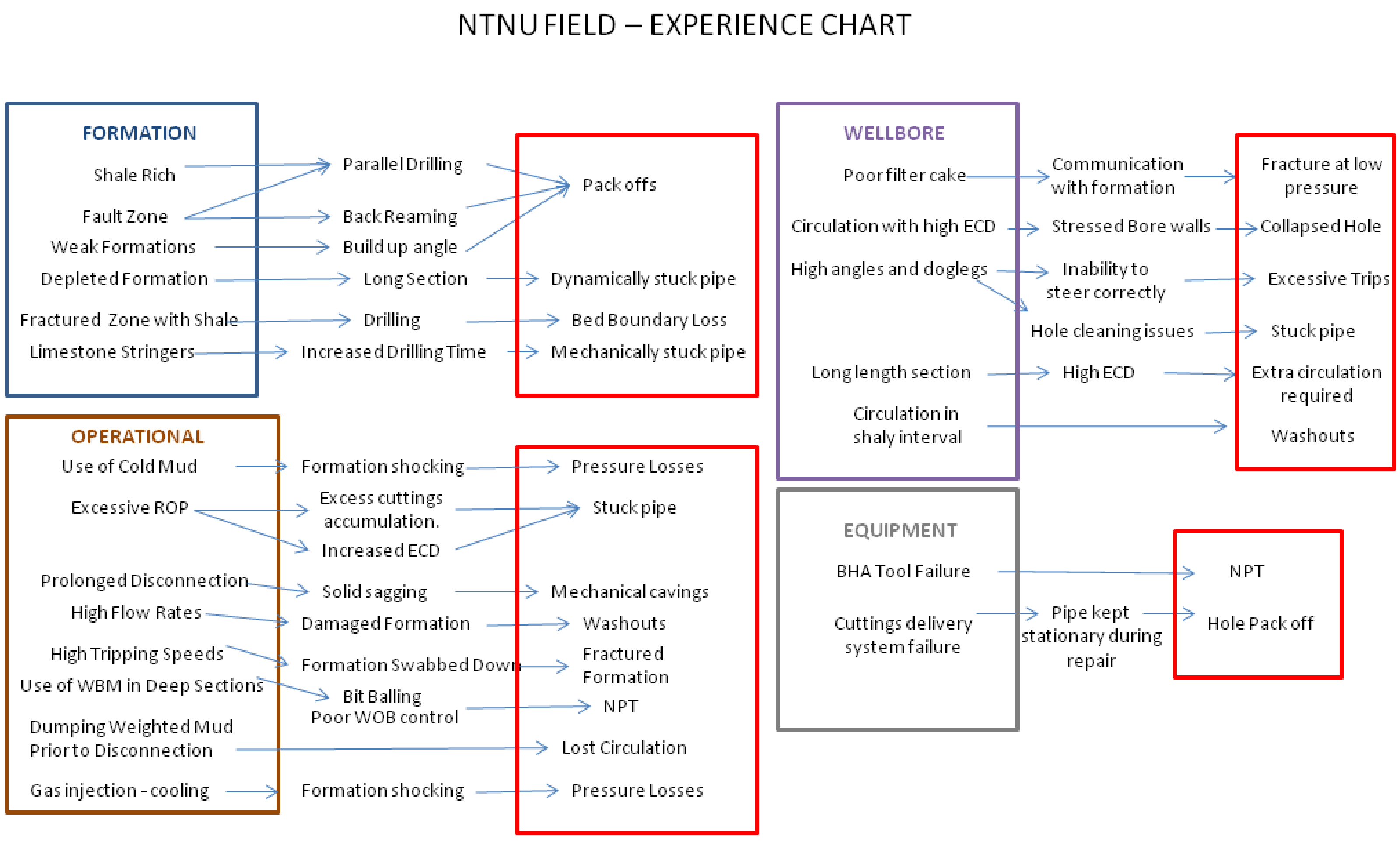

Figure 5: NTNU Field negative experience chart.

3.3 Case Study – Well SS-1H

3.3.1 General Well Data

Country	Norway
Area	Lerkendal
Drilling rig:	Trance Rules
Well name:	SS-1H
Slot:	5 (T-template)
Type of well:	Oil Producer in the Imagine 3.2 and Imagine 2 formations
Water depth /air gap:	305 m MSL / 22 m MSL
Wellhead deck:	327 m RKB

3.3.2 Main goal for drilling operations

The primary objective of well SS1 H is to produce oil from a horizontal section of 1586 m penetrating the Imagine 3.2 reservoir zone on the northern flank of the Armin V Field.
SS1 H is planned to penetrate the reservoir zone 1 - 2 times to ensure drainage of the whole reservoir. The secondary objectives of well SS1 H will be to provide geological, geophysical and petrophysical information from the Imagine Formation for an optimised placement of the horizontal producers, ST1 H and ST2 H. Other objectives will be to improve the depth conversion model for the Top Aisha Formation and to identify residual oil saturation after gas flooding in the Intense 1 Formation.

3.3.3 Wellpath description

SS1 H is planned to be drilled vertically for 677 mTVD/MD. Then the well is kicked off, and builds up to 19,36° inclination and 150,88° azimuth at 2145 m MD with a dogleg of 0,40°/100 ft. For the next 364 m there is a hold section before the well gradually seeks 90° inclination and 303° azimuth to reach Target 1 at 4835 m MD. From this point on the well path stays horizontal through the reservoir till Target 4. Final Target 5 is reached at 92,37° inclination and 326,18° azimuth. Overall, the maximum dogleg for the well path is 2,99°/100 ft.

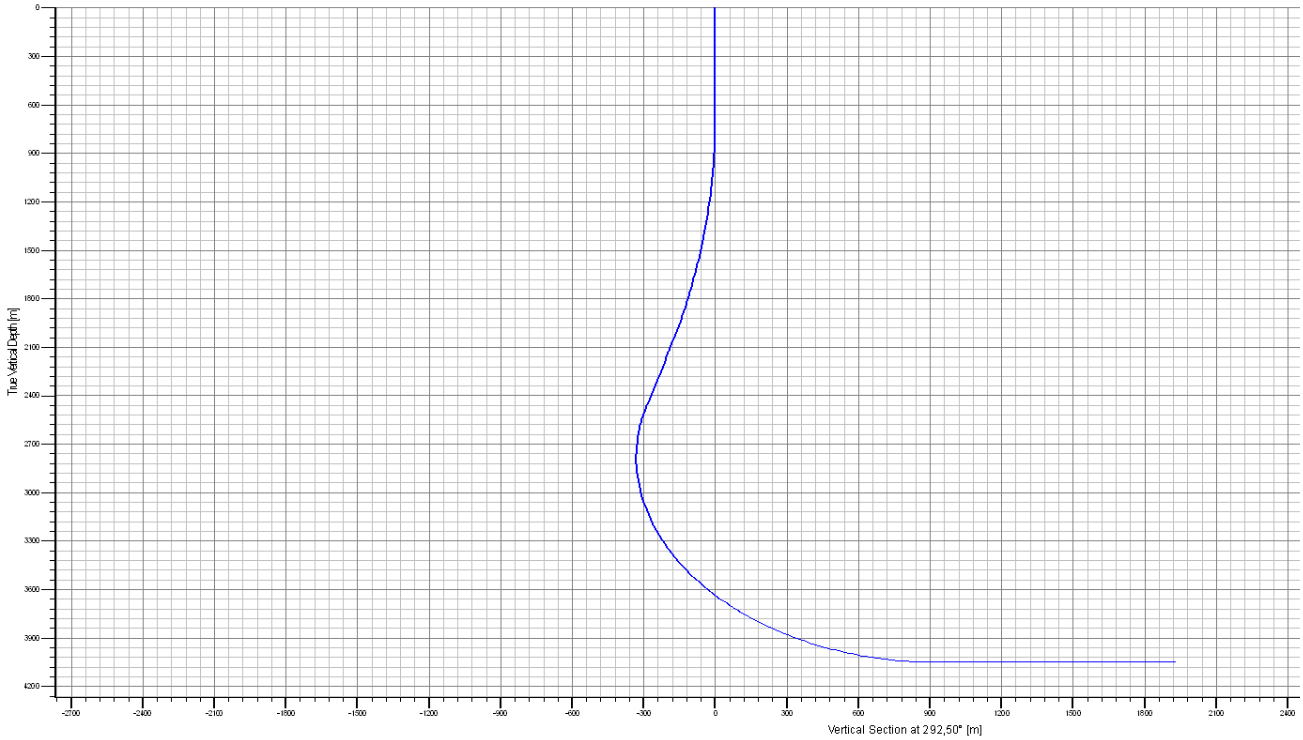

Figure 6: SS1-H planned Well path.

3.3.4 Risks and Uncertainty

Risk factors and uncertainties in the mainbore are related to the presence or absence of good reservoir properties and the presence of faults in the target areas. An area characterized by poor seismic data quality is present close to the planned trajectory. This area is interpreted to be a zone with several small faults.

Uncertainties have been addressed by placing the mainbore targets in areas where good reservoir properties may be expected, based on the geological model that includes data from offset wells, and in areas were seismic data is interpretable with reasonable confidence. The mainbore trajectory is in addition placed close to the SP3 H well where good Imagine 3.2 reservoir properties are observed. The trajectory is also planned to be drilled twice through the reservoir zone stratigraphy. The presence or absence of diagenetic effects such as chlorite coating is also a risk factor.

3.3.5 Reservoir pressure and temperature

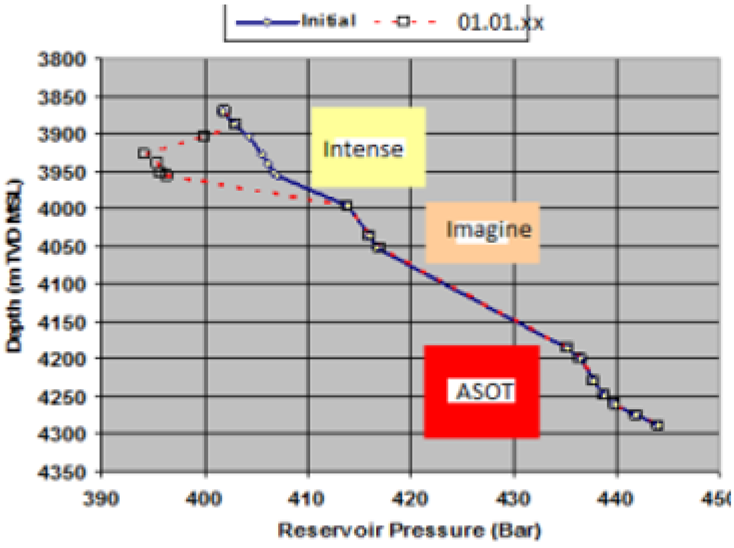

Figure 7: SS1-H Pore pressure prognosis.

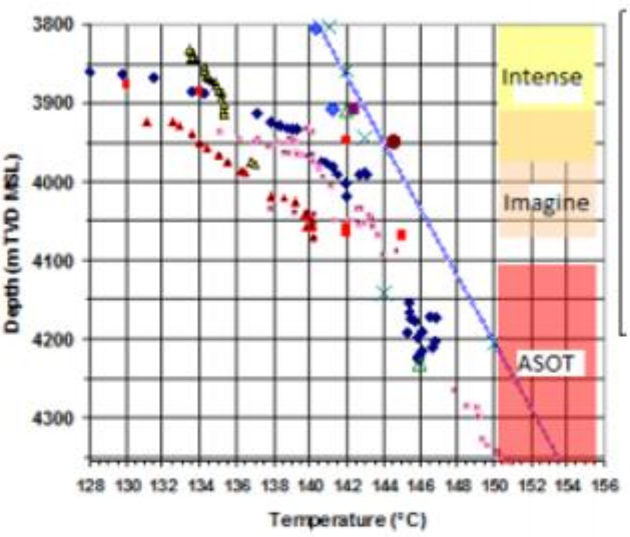

Figure 8: Armin V. reservoir temperature gradient.

No obvious structural complications are observed on the seismic data along the recommended well bore in the overburden.

3.3.6 Prognosis for the existence of shallow gas

Shallow gas is not predicted for this well. A 9 7/8” shallow gas pilot was drilled in SS2 H, the first well on the T-template. Evaluation of data from the pilot classified the T-template area as shallow gas class 0.

3.4 Case Study – Well SS-1H - Sidetrack

When drilling the 12.25” hole section at 2250 MD, the operations were stopped due to bad weather condition and the well was left idle. Few days later after an improvement in weather, drilling was allowed to proceed, but the hole had collapsed.

Following the original well path would lead to unstable formations, therefore a technical side track is required. The sidetrack should kick off below the 13 3/8" casing shoe, running a new 12 1/4" section in parallel to the old one and close in towards the old well path aligning on the targets.

4 Results

This section demonstrates how the industry applies experience and presents them. The drilling program and operating procedure are often referred to as ‘best practice’

4.1 Well Information / Goals

Objectives:	• Open hole sidetrack well at 2120m MD after the 13 3/8” casing shoe. • Drill 12 ¼” section to TD: 4322m MD. Total length to be drilled: 2202m • 9 5/8” casing will be set in Intense 3 Fm
Major operational risks:	• Not able to sidetrack with RSS: PowerDrive Xceed 900 • BHA Tool failure • Differential sticking across permeable formations while drilling • Pumping Cement plug – damaging the formation. • Hole cleaning issues • Running casing in permeable formation leading to differential sticking.
Major HSE Risks:	• Well control; involved personnel have to focus on barrier envelopes and volume control during all phases of the operation. • Falling objects. • Exposure to cement dust. • Proper PPE when handling drilling fluid and chemicals.
Well Information:	**Status:** • 300m of open hole exposed below the 13 3/8” casing shoe. • The well is filled with 1.45SG WBM. • BOP is tested to 10,000 psi **Technical data:** • Pore Pressure at TD: 1.05 SG • Estimated temperature at TD: 147°C • TFA: 0.96 in^2 • Max Pump rate: 2600 l/min

Barriers:	**Primary**: Fluid Column **Secondary:** 13 3/8" casing and cement, wellhead, high pressure riser and drilling BOP.

Table 2: General Well information.

4.1.1 General Remarks

The 12 ¼" section will be sidetracked from the original well plan and follow a parallel well path drilling further into Intense Fm than done previously on Armin V, and high focus on borehole stability is required. The strategy is to drill the section in two runs with RSS PowerDrive Xceed 900. ROP has been sacrificed to have improved control on the well path. TD criterion is to stop 5m TVD above top Intense 2.2 Fm. By then, the GR/Res sensors in BHA should have identified top Intense 3 fm. An extended LOT was performed on well SS-3 H which approves for drilling into Intense 4/3 Fm in the 12 ¼" section.

4.2 Well SS-1H Side Track Experience Chart

The analysis of the NTNU field data and the drilling experience from the wells drilled on the Armin V. field is used to develop an experience chart for the SS1-H sidetracked well. Is Negative experience is outlined linking drilling processes to NPT related events under the circumstance stated. The experience is divided between 'Formation', 'Operational', 'Wellbore' and 'Equipment'. The chart will draw out the actions under each category leading to NPT related issues that are highlighted within the red field as displayed on the chart. Understanding the experience chart will help to prepare a better risk assesment and improve well planning altogether to mitigate most of the NPT related issues that could be experienced when drilling the 12.25" sidetracked section.

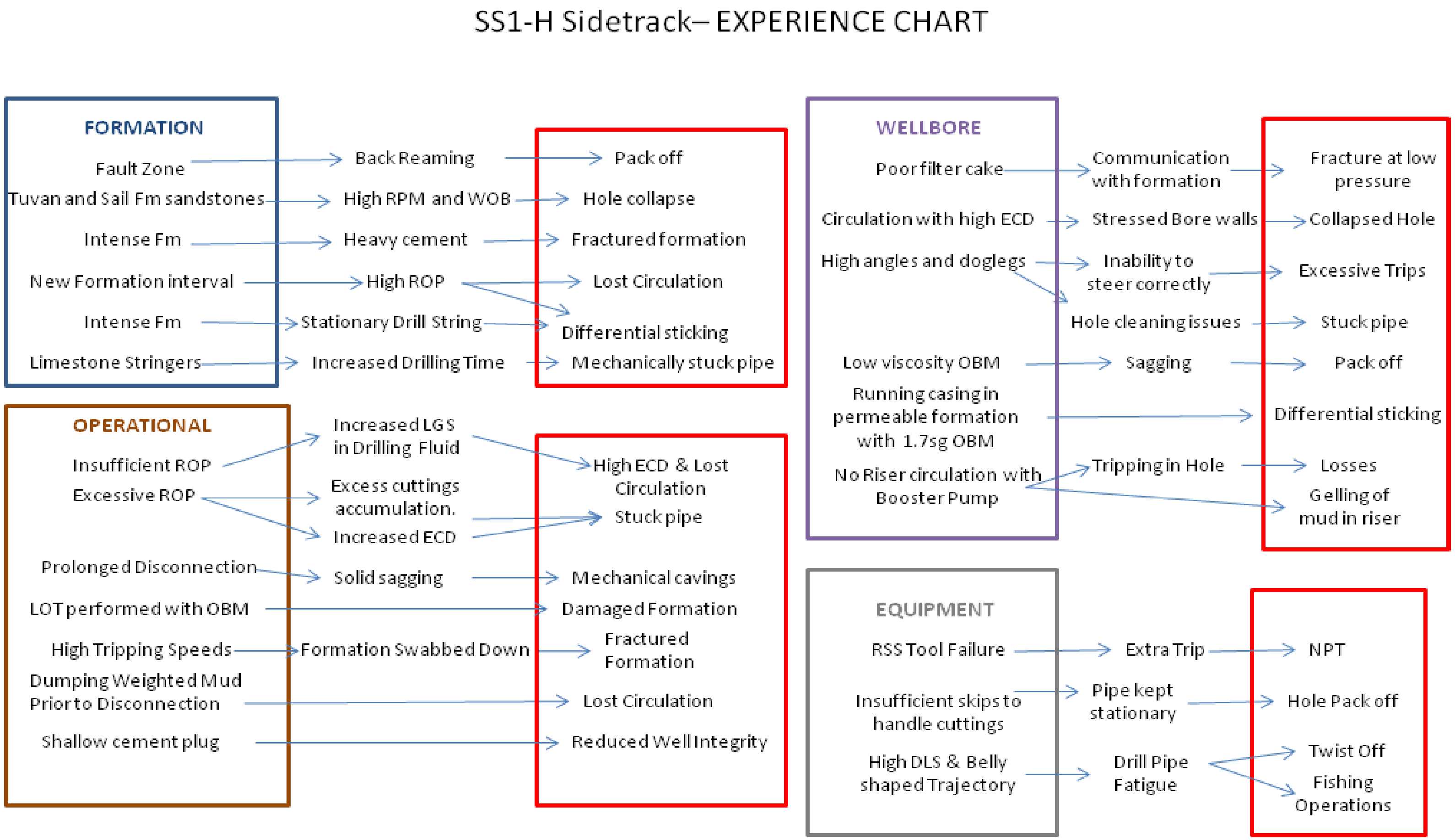

Figure 9: SS1-H Sidetrack negative experience chart.

4.3 Risk Assesment

The risk assessment will address general projects risks as well as risks related directly to operations involved in sidetracking the well and drilling the well to the planned depth based on drilling experience in the Armin V field.

The original wellpath was sidetrack due to prolonged disconnection after waiting on weather. Lack of circulation in the well while left idle resulted in sagging and cavings eventually leading to a hole collapse. This negative experience is outlined in the SS1-H sidetrack experience chart. The risk assessment form for the sidetrack is designed accordingly and will address this potential hazard and mention risk reducing measures so that the probability of this NPT related event occurring again is lower. Weather forecasts will be checked and operations will be planned ahead to avoid keeping the wellbore idle. Back up equipment and mud skips will be made available when drilling through zones with higher than the average ROP of the section and a controlled circulation will be maintained in the annulus at all times.

To eliminate issues with the old collapsed hole a 150m cement plug will be set and tested. The sidetrack will then kick off below the 13 3/8" casing shoe , running a new 12 1/4" section in parallel to the old one keeping a safe distance away from the old well path making sure a separation factor (SF) ≥ 1 is fulfilled for all surrounding wells, as per the Anti collision summary report.

The risk assessment form and the operation guidelines will address risks related to setting the cement plug to avoid issues with the old collapsed hole. The strategy for side tracking and drilling the 12.25” well section is detailed in the 4.2.4 operational guidelines section with added notes under the procedures to address potential risks learned from experience, involved for the operational stages.

Using the SS1-H sidetrack negative experience chart in figure 10, an optimum operational guideline and risk assessment is designed. The assessment form designed takes risk reducing measures into consideration for general project risks, setting the cement plug , eliminating issues with the old well and drilling the sidetracked well to the planned TD with a lower probability of NPT events from occurring when compared to the original well.

Impact	Probability			
	1 (High)	2 (Moderate)	3 (Low)	4 (Very Low)
1 (Very high)	Very high	Very high	High	Moderate
2 (High)	Very high	High	Moderate	Low
3 (Moderate)	High	Moderate	Low	Low
4 (Low)	Moderate	Low	Low	Low

4.3.1 Risk Assessment Form

			Initial risk (1-2)				Final risk (1-4)			
Ref.	**Hazard description**	**Consequence description**	**Impact**	**Freq**	**RF**	**Risk reducing measures**	**Impact**	**Freq**	**RF**	**Responsible**
12 1/4" Hole Side track Section										
General Project Risks										
1	Lifting hazards	Harm to personnel and damage to equipment.	**2**	**2**	**High**	Coordinate hoisting activities with picking operator and supervisors. Safety hand to be involved during Rig up. Proper Training and PPEs provided.	**3**	**4**	**Low**	Operating Company / Service Provider
2	Loss of radio communication	Harm to personnel due to misunderstanding communications	**2**	**2**	**High**	Establish Radio protocol in the safety meeting. Ensure hand signals are in place for important procedures. Ensure sufficient headsets are available with a battery change schedule.	**3**	**4**	**Low**	Operating Company / Service Provider
3	BOP elements pressure test failure	Lost time and cost	**2**	**3**	**Moderate**	BOP should be tested and serviced prior to the job. Rig should stock spare components	**4**	**4**	**Low**	Operating Company / Service Provider

4	FIT insufficient for planned operations	Unalbe to apply drilling program. Well control concerns, lost time and potential hazard to personnel	**2**	**3**	**Moderate**	May require additional casing string and re-design of drilling program. Remedial cement job, redrill and test.	**3**	**3**	**Low**	Drilling Engineer
5	Tool Failure	Washouts. Extra trip loss of time and cost	**2**	**3**	**Moderate**	Focus on mud parameters, monitoring solids and sand content. Monitor stick/slip issues and vibration levels. Back up equipment available.	**3**	**4**	**Low**	Drilling Engineer / Mud Engineer
6	Limited deck space	Delayed operations	**3**	**3**	**Low**	Plan ahead. Use dedicated vessel. Send unecessary equipment to shore.	**3**	**4**	**Low**	Drilling Supervisor
7	Top Hole vibrations	Damage to BHA/ rig equipment / Drilling performance	**2**	**2**	**High**	Incorporate Shock sub, review drilling practices and adjust drilling parameters	**3**	**2**	**Moderate**	Drilling Engineer
8	Mud Losses	Additional cost/time to cure losses. Collapse of the well or stuck pipe	**3**	**1**	**High**	Develop robust contingency plan for lost circulation, include this in pre-spud/section meetings, ensure clarity of the plan. BASP to develop lost circulation decision tree. Have sufficient stock of cement and LCM to face severe losses event	**3**	**2**	**Moderate**	Drilling Engineer/ Mud Engineer
9	Poor Weather	Harm to personnel. Lost time and cost	**2**	**3**	**Moderate**	Suoervisors should check regular weather forecasts and stop unsafe work activity	**2**	**3**	**Moderate**	Drilling Engineer/Supervisor

Clean-Out/Setting Cement Plug										
1	Contamination of cement slurry with drilling mud	Weak Cement Plug	**2**	**3**	**Moderate**	Use 1 or more displacement plugs. Use mechanical seperator between slurry and spacer to redice contamination	**2**	**4**	**Low**	Drilling Engineer
2	Shallow Cement Plug	Reduced Plug Integrity	**2**	**3**	**Moderate**	Recheck volume calculation before pumping.	**2**	**4**	**Low**	Drilling Engineer
Kick Off & Drilling 12.25" Section to TD										
1	Debris in well after plug drill out	Unstable BHP. Stuck Pipe. Plugged Choke. Damage to BHA	**2**	**3**	**Moderate**	Drill out while pumping at high rate. Controll drill through plug and monitor torque and drag while drilling out.	**2**	**4**	**Low**	Driller/Drilling Engineer
2	Missing Kick Off Point	High Doglegs	**2**	**3**	**Moderate**	Use proper survey tools. Reduce ROP when closing in	**2**	**4**	**Low**	Driller
3	High Doglegs	Unable to run casing	**3**	**3**	**Low**	Ream down high doglegs	**3**	**4**	**Low**	Driller
4	Poor Hole cleaning	Cuttings accumulation in the wellbore. Pack offs, formation fracture and losses. High friction and tool failure.	**2**	**3**	**Moderate**	Attention to hole cleaning parameters. Check shakers for cuttings return, if not evaluate to circulate hole clean or control ROP. Use sufficient time to circulate hole clean after section TD.	**2**	**4**	**Low**	Driller/Mud Engineer
5	Stuck Pipe	Lost time. Sidetrack	**2**	**3**	**Moderate**	Have LCM pill material ready when drilling into depleted formations. Monitor ECD and ROP to keep good hole cleaning practices. Circulate	**2**	**4**	**Low**	Driller/Mud Engineer

						hole clean with maximum RPM before POOH.				
6	Pipe Buckling/Drill Pipe failure	Lost time. Fishing Operations. Sidetrack.	**2**	**3**	**Moderate**	Limit Weight on bit. Limit torque to avoid stalling out when drilling shoe track. Simulate bucking forces using friction factor of nearby wells	**2**	**4**	**Low**	Drilling Engineer
7	Drill String Twist off	Possible gas/hydrocarbon at rig floor. Explosion risk. Formation damage due to well kill.	**2**	**3**	**Moderate**	Establish maximum torque limit during drilling operations. Monitor drilling data for signs of pipe washout.	**2**	**4**	**Low**	Drilling Engineer/ Driller
8	Losses due to depletion caused by nearby production wells	Losses. Sidetrack	**2**	**3**	**Moderate**	Baroid to design an optimum fluid to reduce ECD. Have LCM pill material ready when drilling into depleted formations. Focus on low fluid losses	**2**	**4**	**Low**	Mud Engineer
9	Surge/Swab when RIH/POOH	Fracture Formation, Swab kick	**1**	**3**	**High**	Tripping speed to be within the margin according to surge and swag calculations	**1**	**4**	**Moderate**	Drilling Engineer
10	High Dogleg when exiting window	Problems running casing. Unable to exit window without entire BHA	**2**	**3**	**Moderate**	Taking time to drill out cement plug with low WOB. Correct PowerDrive practice should be followed.	**2**	**4**	**Low**	Drilling Engineer/Driller
11	Bit damage/failure through Tuvan sandstones	Extra Trip. Lost time and costs.	**2**	**3**	**Moderate**	Low RPM and WOB as per DOP through formations with sandstones to improve bit life	**2**	**3**	**Moderate**	Drilling Engineer/Driller

12	Well accidentally shut in while pumping fluid	Fractured Formation. Well control problems.	**1**	**3**	**High**	Maximum allowable surface pressure for the mud weight must be used. Operational adjustments made based on FIT. Install pressure relief valve upstream of choke.	**1**	**4**	**Moderate**	Drilling Engineer
13	Drilling out of zone into shale layers	Possible stuck pipe and loss of BHA. Sidetracking and lost time and costs.	**2**	**3**	**Moderate**	Monitor changes in ROP and directional control and other drilling paramter changes to observe lithology contol. Monitor changing LWD data if available.	**2**	**4**	**Low**	Drilling Engineer
14	Borehole Instability	Formation Damage. Stuck Pipe. Lost BHA. Target not reached.	**2**	**3**	**Moderate**	Manage drawdown through all stages of operation. Avoid trouble zones. Minimize time in hole without circulating.	**2**	**4**	**Low**	Drilling Engineer
15	Prolonged Disconnection & Stationary Drill Pipe	Sagging.Cavings collapsed hole. Lost time	**2**	**3**	**Moderate**	Plan ahead. Check weather forecasts. Back up equipment and mudskips. Keep controlled circulation and pipe rotation in the annulus.	**2**	**4**	**Low**	Drilling Engineer

Table 3: 12.25" Sidetracked Section – Risk Assessment

4.4 Well SS-1H Side Track Drilling Program

As mentioned in section 3.4, a technical side track is required on the SS-1H well, which should make a kick off below the 13 3/8" casing shoe, running a new 12 1/4" section in parallel to the originally planned well path and close in on the targets.

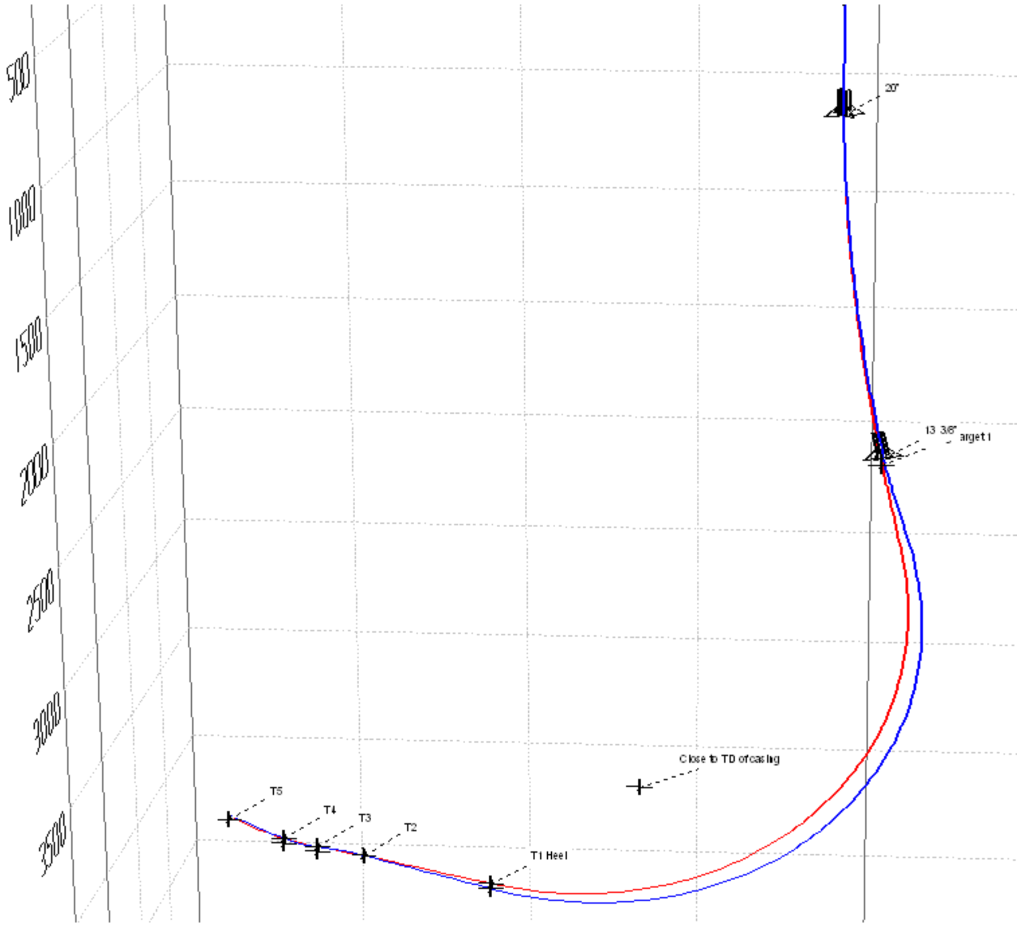

Figure 10: Old Wellpath vs Sidetracked Wellpath.

Interval	2120m MD – 4322m MD
Section length	2202m
Inclination	20.39˚ - 65˚
Azimuth	198.69˚ – 298.54˚

Table 4: 12 ¼" Sidetracked section directional plan.

4.4.1 Operational Guidelines:

1. M/U and R/B cement stand. M/U 12 ¼" BHA according to Appendix E**.**

NOTE: Ensure RSS PowerDrive Xceed 900 is included in BHA.

2. Pump a 4500l preflush, spot a viscous pill and then set a 150m cement plug. Pull back 30m above the TOC, close the annular and reverse circulate the string clean. Perform a hesitation squeeze and attempt to squeeze away 800l. If losses have been observed it may be necessary to set a further cement plug.

NOTE 1: Recheck volume calculations before pumping.

NOTE 2: When placing the cement plug, continuously monitor the backside surface pressure to check if cement is circulated up the annulus.

NOTE 3: Avoid contamination of cement slurry with drilling mud during or immediately after placement.

3. Wash and ream cement plug until it takes enough WOB and Torque to ensure the plug is solid enough to start sidetracking.

4. Displace drilling mud to 1.7SG Paratherm OBM. Kick off and perform the sidetrack to the new well path, keeping a safe distance away from the old well path making sure a separation factor (SF) ≥ 1 is fulfilled for all surrounding wells, as per the Anti collision summary report.

5. Drill 3m into new formation and perform FIT.

6. A FIT to 1.79 sg EMW is enough to fulfill the ECD and kick tolerance requirements. Max ECD in this section will be approx. 1.75 sg. Fracture gradient is approximately 1.86 sg.
The kick tolerance requirement is based on a PP of 1.49 SG in the Tuvan formation and a setting depth of 13 3/8" casing @ 2091m TVD-RT.

7. Drill 12 ¼" hole to according to well path in Appendix D.

NOTE 1: Avoid high doglegs. PowerDrive practice should be discussed before changing settings.

NOTE 2: It is recommended to slow down on RPM and WOB through the Tuvan and Sail sandstones to improve bit life. Recommended parameters are:
RPM: 60-80 RPM, WOB: 10-15 ton.

NOTE 3: After drilling stringers; ream interval before continue drilling.

8. At 3900m MD, stop drilling. Circulate hole clean while R/U to run WL Keeper Gyro inside drill string. Run Gyro according to Scientific Drillings procedure.

NOTE: Minimum depth for performing Gyro run is 500m MD before entering reservoir (top Intense Fm) to fulfill governing documents.

9. Prior to bit trips: Circulate hole clean. Flow check while rotating and POOH.

NOTE 1: Circulate hole clean with maximum RPM before POOH in order to minimize the risk of getting stuck.

NOTE 2: Risk of swabbing when POOH. Tuvan Sst is likely to be Hydro Carbon bearing. Follow Surge and Swab simulations to find the ideal tripping speed prior to pulling out.

10. At TD: Circulate hole clean. Flow check while rotating and POOH. If back reaming is necessary, run in minimum 3 stands or back to TD of the section. Rack back BHA.
NOTE 1: TD of section to be set by the geologist and drilling engineer.

NOTE 2: Circulate hole clean with maximum RPM before POOH in order to minimize the risk of getting stuck.

11. M/U Jet sub and SL-tool.

12. RIH, wash BOP and wellhead area. Retrieve wear bushing and POOH.

13. R/U and run 9 5/8" x 10 ¾" casing according to Table 5.

NOTE 1: Final setting depth for the 9 5/8" casing will depend on the section TD.

NOTE 2: Check float and shoe for flow through and holding back flow/pressure.

NOTE 3: Install 9 5/8" back-off sub in string to be able to back off approx. 200 m below BOP when casing shoe enters Tuvan Sst.

NOTE 4: Due to high string weight the casing can possibly be "one-way" at a given depth. Check lifting capacities on top drive, tensile strength on casing and limitations on elevator and casing hanger.

NOTE 5: Check weather window prior to commence with running casing string into OH.

14. P/U casing hanger and RIH on 5" landing string. M/U cement stand. Land hanger in wellhead and establish circulation.

15. Cement 9 5/8" x 10 ¾" casing according to separate procedure.

NOTE: The casing will be cemented using foam cement to avoid fracturing the Intense Fm.

16. Set and pressure test seal assembly. Pressure test 9 5/8" x 10 ¾" casing and POOH with running tool while performing pressure test.

NOTE: The casing pressure test has to be performed within one hour after bumping the cement plugs. If the pressure test can not be performed within one hour, the pressure test has to be performed against the BOP before starting drilling cement with the 8 ½" BHA.

17. Lay down drilling BHA. RIH with jet sub, SL-tool and wear bushing. Set wear bushing and POOH.

NOTE: Pressure test BOP while setting the wear bushing (Brechan, 2014).

4.4.2 Drill String Design/BHA

The complete 12 ¼" section is planned to be drilled using the Schlumberger PD XCEED 900 RSS system. For full BHA design, see attached BHA in Appendix E

Max drill string RPM while drilling: 120 rpm

Max drill string RPM while back reaming: 60 rpm

Max drill string RPM while off bottom: 60 rpm

Max Bit RPM at all times not to exceed: 125 rpm

4.4.3 Torque and drag

Torque and drag simulations are performed using WellPlan™ Torque and Drag Analysis software. Friction factors: Closed Hole/Open Hole = 0.25/0.3. Torque limits and tension on the drill string is calculated using the WellPlan™ model posted in Appendix B. Results of the torque and drag analysis for this section is posted in Appendix G.

MD(m)	**2200**	**3000**	**3200**	**4000**	**4200**
On Bottom Torque (KNm)	9.4	7.4	8.4	10.1	11.1
On Bottom WOB (KNm)	120	60	70	120	120
Tripping In (rpm)	60	60	60	60	60
On Bottom Rotary speed (rpm)	120	100	70	120	120

Table 5: Drill String rotary parameters.

4.4.4 Bit

Bit nozzles on the rig should meet the recommended TFA: 0.96 in^2. It is recommended to use even size nozzles in the PDC bits to avoid plugging of the largest nozzles.

Size	Manufacturer	Type	Model	TFA
12.25”	Security DBS	Tri-Cone	XL16	0.96 in^2

Table 6: Bit Recommendation.

4.4.5 Hydraulics

Hydraulic simulations are performed using the WellPlan™ Hydraulic Analysis software. Calculations are done using the WellPlan™ hydraulics models attached in Appendix C to find the optimum ROP and hole cleaning rate according to the selected RPM through the section. The graphical results are attached in Appendix H.

MD (m)	Flow (lpm)	Circulating Pressure (kPa)	ROP (m/hr)	TFA (in^2)	MW (sg)
2200	2100	34000	30	0.96	1.7
3000	2200	47000	30	0.96	1.7
3200	2060	50000	20	0.96	1.7
4000	2400	62000	20	0.96	1.7
4200	2600	63500	20	0.96	1.7

Table 7: Hydraulics parameters along the section.

4.4.6 Data Acquisition

The entire section is to be drilled with a MWD using a specific geomagnetic correction. Gamma Ray / Resistivity: Gamma Ray will be done with arcVISION* Array Resistivity Compensated Tool. This is, it can be run alongside the MWD tools, to reduce the number of trip-in/-out.

4.4.7 Drilling Fluids

The entire section will be drilled with Paratherm OBM. This mud has been used on the latest wells (SS-2 H, SS-3 H and R3 AH) on the Armin V field. Protective equipment is required when handling Paratherm OBM.

12.25" section	**Inclination (°)**	**Temperature(°F)**	**Pressure(bar)**	**Base Density (sg)**	**PV (cp)**	**YP (cp)**
Depth(m)	20,39	70	1.0133	1.7	38.19	4.13
2202	65					
4322						

Table 8: 12.25" section drilling fluid details.

The first part of the section will be drilled with high average ROP. The ROP will slow down towards the middle part of the section, giving more LGS in the drilling fluid, which will result in a need for dilution with new premix. The aim is to keep the viscosity low for maintaining the flow rate while at the same time ensuring sufficient low end viscosity for hole cleaning and stability with respect to avoiding 'sag'.

Dilution should be minimized towards the end of the section in order to achieve a system, which is sufficient sheared before pulling out of hole. Extra emulsifiers may be added before reaching section TD, giving an extra boost to the stability. CaCO3 and G-seal will be added before entering the reservoir to prevent differential sticking and minimize risk for lost circulation. A 6 m^3 LCM pill will be ready in the chemical pit prior to drilling into reservoir in the Intense formation. Consider to pump the LCM pill on TD before POOH.

4.4.8 Casing

- The 12 ¼ inch section TD will be set at 4322MD in the Intense sand formation.
- The 9 5/8" production casing and its cement will act as production barrier, drilling barrier and future permanent P&A barrier. Getting this casing to TD and achieving an acceptable cement job is critical for well integrity.
- Top of Intense formation should be identified either from MWD, mud logging or drilling break prior to setting a casing.

		Burst	Collapse	Axial		Tri-axial			
Pipe	**Connection**	**Rating (bar)**	**SF**	**Rating (bar)**	**SF**	**Compression Rating (KN)**	**Tension Rating (KN)**	**SF**	**SF**
9 5/8", 58.400 ppf, P-110 Casing	10.6", Vam, P-110	820	1.237	673.45	1.36	4956	8289.118	2.424	1.302

Table 9: Casing details

4.4.9 Cementing

The objective of the cement job is to place the cement minimum 400m MD above the 9 5/8" casing shoe. As learned from experience drawn out in the experience chart, heavy cement in the Intense formation can lead to fracturing. Therefore the casing will be cemented using foam cement to avoid fracturing the Intense formation. If the Tuvan Sst is HC bearing, the casing will be cemented 200 m MD above the permeable zone .Note that the foam cementing operation will require a significant amount of equipment. Final cement slurry composition and displacement rates will be sent to the rig prior to the cement job.

5 Discussion

5.1 Drill String Design

Using the experience gained from wells SS2-H to SS5-H, optimum RPM levels for the drill string are recommended according to the formation drilled, for the drilling plan.
When drilling through the Tuvan formation starting at 3138m TVD all through the Sail formations till 3655m TVD, experience outlined in the experience chart recommends a low RPM and WOB to avoid hole collapse and time lost on an extra bit trip.
It is also noted that the drill string should not have a prolonged disconnection and remain stationary in the Intense formation because learning from experience and the pore pressure prognosis attached on Appendix F, stationary drill string will result in differential sticking in this formation. Using the experience chart, the sidetracked well path was designed using the 'Compass' software with low angles and doglegs to help avoid hole cleaning issues and the inability to steer correctly with the RSS.

5.2 Torque and drag

Torque is kept relatively low to avoid mechanically stuck pipe when drilling through possible limestone stringers, which has been highlighted in the experience chart.
Tripping speeds are kept low to 36m/min with a low rpm to avoid swabbing down and potentially fracturing the formation as learned from experience.

Using the WellPlan™ software, the parameters selected after evaluating the experience transferred, are verified through the Torque and Drag Analysis module.
As per the theory for forces acting on the drill string along a curved well attached in Appendix A, the normal force of the drill string is calculated using:

$$N_i = \sqrt{\left(\beta w_i \sin\left(\frac{\theta_{i+1}+\theta_i}{2}\right) + F_i\left(\frac{\theta_{i+1}-\theta_i}{S_{i+1}-S_i}\right)\right)^2 + \left(F_i \sin\left(\frac{\theta_{i+1}+\theta_i}{2}\right)\left(\frac{\alpha_{i+1}-\alpha_i}{S_{i+1}-S_i}\right)\right)^2}$$

The normal torque force along the drill string is calculated using:

$$\tau = F_N \times r \times \mu \times \frac{|A|}{|V|}$$

And the Von Mises stress acting along the drill string is calculated using:

$$\sigma_{vm} = \sqrt{\frac{(\sigma_{rj} - \sigma_{hj})^2 + (\sigma_{aj} - \sigma_{rj})^2 + (\sigma_{hj} - \sigma_{aj})^2 + 6\sigma_{sj}{}^2 + 6\sigma_{tj}{}^2}{2}}$$

Details of the equations and numerical models used to perform all the torque and drag calculations in the WellPlan™ software are attached in Appendix B. The graphical results of tension and bucking calculations and other analysis of forces acting on the drill string is presented in Appendix G

5.3 Hydraulics

ROP across the whole section is kept relatively low since from experience learned in the Armin field, a high ROP at new formation intervals leads to lost circulation. Excessive ROP can lead to excess cuttings accumulation and increased ECD which could result in stuck pipe. The ROP and the pump rate is sufficient enough to avoid increased LGS in the drilling fluids, which could result in high ECD and lost circulation. Circulation with high ECD could stress the bore walls and lead to collapsed hole. The calculated circulation pressure is within the fracture gradient. Using this hydraulics plan with low ROP and RPM especially through the Intense formation with a lower fracture gradient and the Tuvan formation with the presence of sandstones learned from experience will have a low probability of NPT events.

ECD is calculated using the equation:

$$\text{ECD} = \frac{P_h + P_f}{0.052(D_{tvd})}$$

Where P_h is the hydrostatic pressure change and P_h is the frictional pressure change to the ECD point while D_{tvd} represents the TVD point of interest. Further details to the model used are attached in Appendix C.

From figure 21 in appendix H, it can be observed that the pore pressure is higher than the annular pressure below the casing show at 2200m MD using a lower mud weight of 1.6 SG. Hence a mud weight of 1.7SG is recommended and the results shown in figure 22 show that the calculated ECD is within the pore and fracture pressure limits, validating the use of 1.7 SG OBM as the drilling fluid.

5.4 Drilling Fluids

As outlined in the experience chart a low viscosity mud will result in sagging which can lead to a pack off. Experience learned from the NTNU field warns that circulating drilling fluid with high ECD could stress the bore walls leading to a hole collapse.

Therefore a high viscosity 1.7 SG OBM is which also meets the calculated ECD requirements as shows in figure 22.

5.5 Casing

It is recommended to circulate a low density mud prior to running the casing, since from experience in the Armin field, running the casing through a permeable formation with 1.7SG OBM can lead to differential sticking.

6 Conclusion

As the industry looks for different methods to reduce costs for deep water wells in order to compete with shale oil recovery, understanding the drivers for time usage is important since most of the costs involved in well construction are time dependant. Sources of NPT are outlined and the extraction of experience from drilling data and its impact on sources of NPT is discussed. Well Planning software models were used to define the key parameters in mitigating NPT events linked to on-bottom drilling time.

The NTNU field case study is a representation of how understanding sources of NPT is important for extracting experience from drilling data. The case study depicts the analysis of physical drilling data and the successful extraction of experience and the impact on NPT related sources:

- Formation Stability – Hole Inclination, Faulting, Mud weight.
- Depletion.
- Drilling Practices.
- Hole Cleaning.
- Data Acquisition.
- Well Bore Geometry and Design.
- Mud Weight Management.
- ECD Control.

The successful extraction of positive and negative experience from these sources has assisted in designing an experience chart relative to simplified sources of experience:

- Formation
- Operational
- Wellbore
- Equipment

The analysis of the NTNU field, wells and drilling data concludes that poor risk management in terms of failure to identify significant risks in the planning stage is probably the leading cause of NPT in this field. Applying a good risk management strategy would result in economic and efficiency savings.

The results and conclusions of the NTNU field case study was used to assist in designing a risk assessment, operation guidelines and an experience chart for the SS-1H well side track using the Armin V. field drilling experience. The use of experience transfer and well planning software models is effective in designing a drilling program for the side track with the optimum parameters to avoid NPT related events.

In conclusion, this study details how understanding sources of NPT and drilling experience followed by the successful extraction of experience from drilling data and transfer into the planning phase along with numerical models from well planning software is successful in reducing the probability of NPT events for the next well. This was done by designing a risk assessment and drilling program, using experience gained from wells drilled in the same or similar fields.

The industry is good at handling positive experience and carrying forward good drilling practices. This study shows that negative experiences can be used effectively in well planning stages to help reduce the risk of NPT related events. However it is difficult to carry forward and apply a vast amount of experience from different fields to particular wells since the type of experience may vary according to the geographical area of the field. Drilling learning curves can be improved only after a number of wells have been drilled and experience is efficiently transferred to reduce risks and improve the drilling efficiency of the next wells.

7 Future work

This paper has addressed integrating planning and experience transfer to reduce NPT related to drilling operations. A further study is required to explore the methods of integrating experience transfer with planning and real time surveillance to further reduce the risk of NPT related events and reduce the overall costs of drilling in complex wells. Further work should involve the following:

- How experience can be captured and transferred effectively from different information sources and then stored in retrievable cases.
- Designing a system that integrates advanced well planning numerical models and modern 3D visualization with rig operations in real time.
- Integrating an online experience transfer system with existing well planning and real time drilling software like eDrilling.

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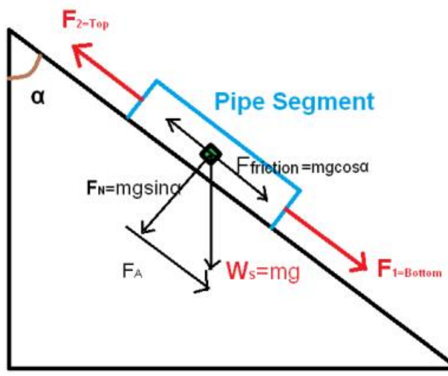
Appendix A – Torque and Drag

Torque & Drag models can be applied to diagnose the measured weights and torques that can be expected during tripping in, tripping out, rotating on bottom, rotating off bottom, sliding drilling, back reaming. Based on the simulation results, engineers are able to determine if the well can be drilled, or to evaluate the events occurring.

The Torque & Drag model in well planning software is usually based on a 'Soft String' model.
The soft string model assumes zero bending stiffness in a pipe which is treated as an extendible cable. A 'Stiff String' model includes the increased side force from stiff tubular in curved hole, as well as the reduced side forces from pipe wall clearance. Along with this, the effect of mud properties, wellbore deviation, tortuosity and other parameters can also be studied and applied by using a Torque & Drag model.

For a straight Borehole (Inclined Well Model)

From force balance, applying the condition of equilibrium along the axial directions, the effective force along the axial direction is calculated. Representations of the Pipe segment are, showed below



Balancing the forces along the inclined plane; (Taboada et al. 2014)

$$dF = w\Delta s(cos\alpha \pm \mu sin\alpha)$$

When the drillstring is stationary, an increase or decrease in the load will lead to upward or downward movement of the drillstring. Integrating the Equation stated above, the top and bottom load limits, one can obtain the force in the drill string as:

$$F_{Top} = F_{Bottom} + w\Delta s(cos\alpha \pm \mu sin\alpha)$$

The first term in the bracket defines the weight of the pipe and the second term defines the additional friction force required to move the pipe. The change in force when the motion starts either upward or downward is found by subtracting the weight from the forces defined above.

The static weight is given as:

$$w\Delta s cos\alpha$$

The rotating friction, the torque, follows the same principle. The applied torque is equal to the normal moment multiplied by the friction factor µ. Giving torque as:

$$T = \mu w\Delta sr\ sin\alpha$$

It is important that the unit mass of the drillpipe or the weight is corrected for buoyancy. The buoyancy factor is given as:

$$\beta = 1 - \frac{\rho_{mud}}{\rho_{pipe}}$$

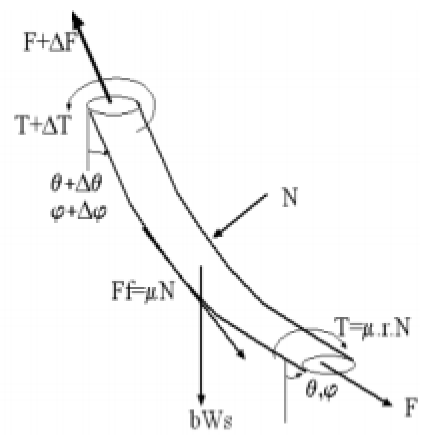
And the buoyed unit mass must be:

$$w = \beta w_{drill\ pipe}$$

The friction torque (M) is composed in two and the relation is given as:

$$M_2 = M_1 + wr\mu sin\alpha$$

For a curved Borehole



(Taboada et al. 2014)

As we can see in the figure the drill string shows a division on segments along. These segments are loaded at the top and the bottom with compressive (-) or tensile (+) loads. Furthermore, these loads (Thermal, Hydrostatic and fluid flow Shear forces) are responsible for the variation in the length of drill pipe.

Balancing between the net force and the vector sum of the axial component of the weight, W and the friction force, one can obtain the first order differential force as the following:

$$\frac{dF}{ds} = \pm\mu\left(\sqrt{\left(\beta w_s sin\theta + F\frac{d\theta}{ds}\right)^2 + \left(Fsin\theta\frac{d\varphi}{ds}\right)^2}\right) + \beta w_s cos\theta$$

Where the plus and minus sign consents for pipe movement direction, ‘’+’’ is when pulling out of the hole (hoisting) where the friction adds to the axial load and ‘’-‘’ is running into the hole (lowering), in other word downward motion, the opposite.

The square root term in equation above is the normal force per unit length for any curved well geometry. The equation is a function of well inclination and azimuth. For each segment, it can be calculated as the following: (Taboada et al. 2014)

$$N_i = \sqrt{\left(\beta w_i \sin\left(\frac{\theta_{i+1}+\theta_i}{2}\right) + F_i\left(\frac{\theta_{i+1}-\theta_i}{S_{i+1}-S_i}\right)\right)^2 + \left(F_i \sin\left(\frac{\theta_{i+1}+\theta_i}{2}\right)\left(\frac{\alpha_{i+1}-\alpha_i}{S_{i+1}-S_i}\right)\right)^2}$$

Where:

- θ = inclination
- α = Azimuth
- w_i = weight per unit length
- β = Buoyance factor

The numerical models used for calculating forces for buckling, axial forces, stresses acting on the drill string etc. are attached in Appendix B.

Appendix A2 - Hydraulics

Hydraulics plays a vital role in drilling operations. The rheological model used allows for reasonable estimates of hydraulics for the conventional well using simple drilling fluids. Therefore, the understanding of the knowledge of rheological data and methods of predicting pressure loss are essential in order to calculate proper pump rate and prevent any barrier in the drilling operation.

Frictional Pressure Loss

When drilling conventional wells, the increase in equivalent circulating density (ECD) by annular losses is usually small compared to the hydrostatic pressure gradient. ECD is the effective density of the circulating fluid in the wellbore resulting from the sum of the hydrostatic pressure imposed by the static pressure and the friction pressure. This is given by:

$$ECD = \frac{\sum P_a}{TVD.g} + \rho_m$$

$\sum P_a$ represents the total annular pressure loss, TVD is the hole true vertical depth, ρ_m is mud density (kg/m^3), and g- acceleration due to gravity (m/s^2).

Frictional pressure losses depend on several parameters including:

Rheology of the drilling fluid.

Flow regime of the drilling fluid.

Drilling fluid properties – viscosity and density.

Flow rate of the drilling fluid.

Hole geometry and drill strong configuration.

When circulating drilling fluid, the pump pressure is the sum of the pressure losses across the surface equipment, drill pipe, drill bit and the annulus.

$$\Delta P_{pump} = \Delta P_{surface} + \Delta P_{dp\ loss} + \Delta P_{dc\ loss} + \Delta P_{bit\ loss} + \Delta P_{assular\ loss}$$

Since the friction between the drilling fluid and the wall of the annulus causes pressure loss, the bottom hole pressures will increase when the mud is being circulated compared to when is not circulated. This bottom hole pressure is caused by the hydrostatic pressure of the wellbore fluid and can be calculated in static with the equation:

$$P_{BHP} = \rho_{MW} \times g \times D_{TVD} \times 10^{-5}$$

P_{BHP} is the bottom hole pressure in bars, ρ_{MW} is the mud density (kg/m^3) and D_{TVD} is the true vertical depth of the well in meters.

Hole Cleaning

Hole cleaning is a major concern when drilling directional wells, and should be monitored and controlled. The accumulation of cuttings may cause significant problems such as stuck pipe and excessive torque and drag. To avoid such problems, it is very crucial to handle this situation properly during planning phase in order to achieve sufficient hole cleaning. Cuttings transport in a wellbore depends largely on the inclination, annular flow velocity, viscosity and pipe rotation.

Hole cleaning in vertical wells:

Hole cleaning efficiency in vertical wells is assessed after determining the settling velocity. The pump rate fast must be fast enough to counteract the settling of cuttings and reduce its concentration in the vertical section. Horizontal wells have a shorter settling distance where cuttings fall to the bottom and the particles build up cuttings bed quickly.

The rate at which cuttings are generated by drilling is:

$$q_{cuttings} = \frac{\pi}{4}\ d_{bit}{}^{2}\, ROP$$

The settling velocity or particle slip velocity is the velocity at which the particle tends to drop in the fluid due to its own weight. The particle slip velocity is dependant on particle size, shape and density; drilling fluid rheology density and velocity; hole pipe configuration and pipe rotation and eccentricity.

An accurate prediction of the slip velocity is required in order to determine the suitable flowrate for improved hole cleaning operations. Cuttings are non spherical and when the flow regime is not laminar, the slip velocity must be found through an empirical drag coefficient C_D.
The two forces acting on the cuttings are gravitational force (F_g) and drag (F_D):

$$F_g = \pi \frac{d_p{}^{3}}{6}\left(\rho_p - \rho_f\right). g$$

Where $d_p$is the particle size, ρ_p is the density of the particle and $\rho_f$is the density of the fluid.

$$F_D = \frac{\pi}{8} d_p{}^{2} \rho_f v_s{}^{2}. C_D$$

Where v_s is the particle velocity and C_D is the drag coefficient

At terminal slip velocity the force of gravity and drag acting on the cuttings particle will be equal, resulting in the slip velocity equation:

$$v_s = \sqrt{\frac{4g(\rho_p - \rho_f)d_p}{3\rho_f C_D}}$$

C_D is the fuction of the Reynolds number of the settling particle. Figure 2 shows the relationship between different flow regimes, the Reynolds number and C_D.

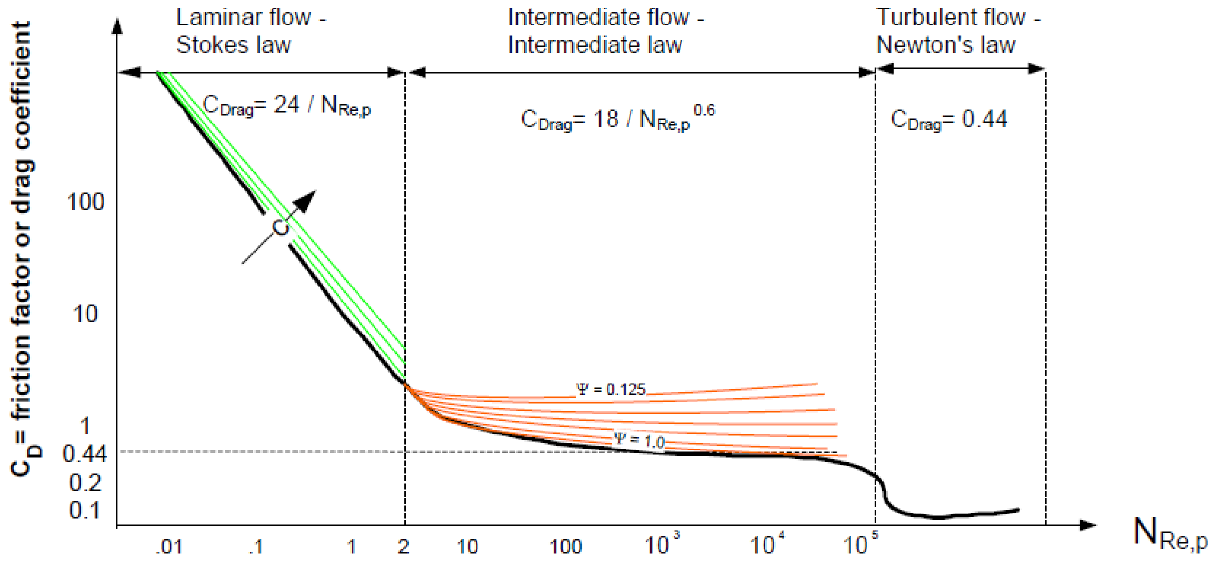


Figure 11*:* **Relationship between Drag coefficient and Reynolds number for settling particles in Newtownian fluids. (Skalle, 2014)**

The annular flow velocity is the flow rate across the annular cross section given as:

$$v_{ann} = Q/Area$$

When the average mud velocity is higher than the slip velocity, the particles will be lifted out of the well at the resulting transport velocity:

$$v_T = v_{ann} - v_s$$

Hole cleaning is quantified using the cuttings transport ratio (R_T):

$R_T = v_T/v_{ann} = 1 - v_s/v_{ann}$

For positive cutting transport ratios the cuttings will be transported to the surface and for a slip velocity of zero, the cuttings will be transported at a velocity equal to the fluid velocity and the cuttings transport ratio will equal unity.

The Wellplan Hole cleaning simulator follows an empirical model based on old experimental studies. The hole cleaning mode is used to display graphics showing how cuttings bed height will build up according to the hole angle and rate of penetration of the drill string. Scenarios can be run to show which flowrate and ROP combinations will result in poor hole cleaning. The numerical models are attached in Appendix C.

Appendix B – Wellplan Torque and Drag Models

Additional Side Force Due to Buckling Calculations

Once buckling has occurred, there is an additional side force due to increased contact between the wellbore and the workstring. For the soft string model, the following calculations are used to compute the additional side force. These calculations are not included in a stiff string analysis because the Stiff String model considers the additional force due to buckling in the derivation of the side force.

Sinusoidal Buckling Mode

No additional side force due to buckling is added.

Helical Buckling Mode

$$F_{add} = \frac{r F_{axial}^{\ 2}}{4EI}$$

Where:

F_{add} = Additional side force

F_{axial} = Axial compression force calculated using the buoyancy method

E = Young's modulus of elasticity

I = Moment of Inertia

r = Radial clearance between wellbore and work string

Axial Force Calculations

The analysis uses two calculations for axial force. In checking for the onset of buckling, the buoyancy method is used. This is because the Critical Buckling Force calculations are based on the same assumptions regarding hydrostatic pressure. For stress calculations, the pressure area method is used.

Buoyancy Method (used to determine buckling)

$$F_{axial} = \sum\left[LW_{air}Cos\left(Inc\right)+F_{drag}+\Delta F_{area}\right]-F_{bottom}-W_{WOB}+F_{BS}$$

Pressure Area Method (used to calculate stress)

$$F_{axial} = \sum\left[LW_{air}Cos\left(Inc\right)+F_{drag}+\Delta F_{area}\right]-F_{bottom}-W_{WOB}$$

Where:

L = Length of drillstring hanging below point (ft)

W_{air} = Weight per foot of the drillstring in air (lb/ft)

Inc = Inclination (deg)

F_{bottom} = Bottom pressure force, a compression force due to fluid pressure applied over the cross sectional area of the bottom component

F_{area} = Change in force due to a change in area at junction between two components of different cross sectional areas, such as the junction between drill pipe and heavy weight or heavy weight and drill collars. If the area of the bottom component is larger the force is a tension, if the top component is larger the force is compression.

W_{WOB} = Weight on bit (lb) (0 for tripping in & out)

F_{Drag} = Drag force (lb)

F_{BS} = Buckling Stability Force = PressExternal × AreaExternal - PressInternal × AreaInternal

Pipe: Area External = π/4 × (0.95 × BOD × BOD + 0.05 × JOD × JOD)

AreaInternal = π/4 × (0.95 × BID × BID + 0.05 × JID × JID)

Collar: AreaExternal = π/4 × BOD × BOD)

AreaInternal = π/4 × (BID × BID)

PressExternal = AnnulusSurfacePress + Σ (AnnulusPressGrad × TVD)

PressInternal = StringSurfacePress + Σ (StringPressGrad × TVD)

Buoyed Weight Calculations

The surface pressure and mud densities specified on the Fluids Column dialog tabs are used to determine the pressure inside and outside of the workstring. Using the equations listed below, these pressures are used to determine the buoyed weight of the workstring. The buoyed weight is then used to determine the forces and stresses acting on the workstring in the analysis.

$$W_{Buoy} = W_{Air} - W_{Fluid}$$

$$W_{Fluid} = \left(MW_{Annular} \times A_{External}\right) - \left(MW_{Internal} \times A_{Internal}\right)$$

For Components with Tool Joints

$$A_{External} = \pi/4 \times [0.95 \times \left(OD_{Body}\right)^2 + 0.05 \times \left(OD_{Joint}\right)^2]$$

$$A_{Internal} = \pi/4 \times [0.95 \times \left(ID_{Body}\right)^2 + 0.05 \times \left(ID_{Joint}\right)^2]$$

Note: The constraints .95 and .5 are used to assume that 95% of the component length is pipe body, and 5% is tool joint.

Components without Tool Joints

$$A_{Internal} = \pi/4 \times \left(ID_{Body}\right)^2$$

$$A_{External} = \pi/4 \times \left(OD_{Body}\right)^2$$

Where:

OD_{Body} = Outside diameter of component body

OD_{Joint} = Outside diameter of tool joint

ID_{Body} = Inside diameter of component body

ID_{Joint} = Insider diameter of tool joint

$A_{External}$ = External area of the component

$A_{Internal}$ = Internal area of the component

W_{Fluid} = Weight per foot of displaced fluid

W_{Buoy} = Buoyed weight per foot of the component

$MW_{Annular}$ = Annular mud weight at component depth in the wellbore

$MW_{Internal}$ = Internal mud weight at component depth inside the component

Curvilinear Model

For a torque drag analysis, the workstring is divided into 30-foot sections. The Straight model assumes each section is of constant inclination. The curvilinear model takes into account the inclination (build or drop) change within each 30-foot section.

In hole sections where there is an angle change, compression in the pipe through the doglegs causes extra side force. The additional side force acts to stabilize the pipe against buckling. The exception to this is where the pipe is dropping angle.

$$Fc > 2\left(\sqrt{\frac{EIWc}{\nu}}\right)$$

$$W_c = 2\left(\sqrt{(W\sin(inc) + F\phi')^2 + F^2\sin^2(inc)\phi'^2}\right)$$

Where:

F = Compressive axial force

Fc = Critical buckling force

I = Moment of inertial for component

E = Young's modulus of elasticity

W = Tubular weight in mud

Inc = Wellbore inclination

□ = Wellbore direction

W_c = Contact load

r = Radial clearance between wellbore and component

Stress Calculations

In the analysis, many stress calculations are performed using the following equations. These calculations include the effects of

Axial stress due to hydrostatic and mechanical loading

Bending stress approximated from wellbore curvature

Bending stress due to buckling

Hoop stress due to internal and external pressure

Radial stress due to internal and external pressure

Torsional stress from twist

Transverse shear stress from contact

Von Mises

Calculated stress data is available on the Stress Graph plot, Summary report, and Stress Data table.

σ_{ij} = stress i = stress type j = location

Stress types Location

r= Radial 1 = outside pipe wall

s= Transverse shear 2 = inside pipe wall

h= Hoop

t= Torsion

a= Axial

Von Mises Stress

$$\sigma_{VM} = \sqrt{\frac{\left(\sigma_{rj} - \sigma_{hj}\right)^2 + \left(\sigma_{aj} - \sigma_{rj}\right)^2 + \left(\sigma_{hj} - \sigma_{aj}\right)^2 + 6\sigma_{sj}^{\ 2} + 6\sigma_{tj}^{\ 2}}{2}}$$

Note: The Von Mises stress is calculated on the inside and outside of the pipe wall. The maximum stress calculated for these two locations is presented in the reports, graphs, and tables.

Radial Stress

$$\sigma_{r1} = -P_e$$

$$\sigma_{r2} = -P_i$$

Transverse Shear Stress

$$\sigma_{s1} = \sigma_{s2} = \frac{2F_n}{A}$$

Hoop Stress

$$\sigma_{h1} = \left[2r_i^2 P_i - \left(r_i^2 + r_o^2\right)P_e\right] / \left(r_o^2 - r_i^2\right)$$

$$\sigma_{h2} = \left[\left(r_i^2 + r_o^2\right)P_i - 2r_o^2 P_e\right] / \left(r_o^2 - r_i^2\right)$$

Torsional Stress

$$\sigma_{t1} = 12 r_o T / J$$

$$\sigma_{t2} = 12 r_i T / J$$

Bending Stress

$$\sigma_{bend\,1} = r_o E \kappa M / 68754\ .9$$

$$\sigma_{bend\,2} = r_i E \kappa M / 68754\ .9$$

Buckling Stress

(only calculated if buckling occurs)

$$\sigma_{buck\,1} = r_o R_c \left|F_a\right| / 2I$$

$$\sigma_{buck\,2} = -r_i R_c \left|F_a\right| / 2I$$

Axial Stress: (tension + bending + buckling)

$$\sigma_{a1} = F_a / A + \sigma_{bend\,1} + \sigma_{buck\,1}$$

$$\sigma_{a2} = F_a / A + \sigma_{bend\,2} + \sigma_{buck\,2}$$

Where:

r_i = Inside pipe radius (in)

r_o = Outside pipe radius (in), as modified by the pipe class

F_n = Normal (side) force, (lb)

F_a = Axial force (lb) as calculated with pressure area method

T = Torque (ft-lb)

E = Modulus of elasticity (psi)

P_i = Pipe internal pressure (psi)

P_e = Pipe external pressure (psi)

κ = Wellbore curvature as dogleg severity (deg/100ft) for soft string model. Stiff String model calculates local string curvature.

J = Polar moment of inertia

Where:

$$J_{body} = \pi/32\left(B_{od}{}^4 - B_{id}{}^4\right)$$

$$J_{joint} = \pi/32\left(J_{od}{}^4 - J_{id}{}^4\right)$$

B_{od} = Body outside diameter, in

B_{id} = Body inside diameter, in

J_{od} = Joint outside diameter, in

J_{id} = Joint inside diameter, in

A = Cross sectional area of component

I = Moment of inertia

R_c = Maximum distance from workstring to wellbore wall (in)

M = Bending Stress Magnification Factor

Viscous Drag Calculations

Viscous drag is additional drag force acting on the workstring due to hydraulic effects while tripping or rotating. The fluid forces are determined for "steady" pipe movement, and not for fluid acceleration effects. You can elect to include viscous drag on the Torque Drag Setup Data dialog.

The additional force due to viscous drag is calculated as follows. Note that this drag force is added to the drag force calculated in Drag Force calculations.

$$\Delta Force = \frac{\Delta P.\pi.(D_h^2 - D_p^2).D_p}{4.(D_h - D_p)}$$

There are no direct computations of fluid drag due to pipe rotation. The method shown here derives from the analysis of the Fann Viscometer given in *Applied Drilling Engineering*.

Compute the shear rate in the annulus due to pipe rotation

$$SR = \frac{4 \times \pi \times RPM \;/\; 60}{D_p^2(1/D_p^2 - 1/D_h^2)}$$

Given the shear rate, the shear stress is computed directly from the viscosity equations for the fluid type. The 479 in the equations below is a conversion from Centipoise to equivalent lb/100ft^2.

Bingham Plastic

$$\tau_t = YP + \frac{PV \times SR}{479}$$

Power Law

$$\tau_t = \frac{K \times SR^n}{479} \text{ if K is Cp, or 4.79 if K is } \frac{dyn}{cm}$$

Herschel Bulkey

$$\tau_t = ZG + \frac{K \times SR^n}{479} \text{ if K is Cp, or 4.79 if K is } \frac{dyn}{cm}$$

No consideration is made to laminar or turbulent flow in this derivation. Additionally the combined hydraulic effects of trip movement and rotation are ignored, which would accelerate the onset of turbulent flow.

Given the shear stress at the pipe wall (in lb/100ft2), the torque on the pipe is computed from the surface area of the pipe and the torsional radius.

$$\Delta Torque = \frac{\tau_t 2\pi L \left(\frac{D_p}{24}\right)^2}{100}$$

In the case of rotational torque the forces are equal and opposite between the pipe and the hole, although we are interested in the torque on the pipe and not the reaction from the hole.

Where:

D_h = Hole diameter (in)

D_p = Pipe diameter (in)

ΔP = Annular pressure loss calculated according to rheological model selected

RPM = Rotational speed of pipe (revolutions/min)

YP = Yield point (lbs/100ft2)

PV = Plastic Viscosity (cp)

ZG = Zero gel yield (lbs/100ft2)

Appendix C – Wellplan Hydraulics Models

Hole Cleaning Calculations

Calculate n, K, τ_y, and Reynold's Number

$$n = \frac{(3.32)(\log 10)(YP + 2PV)}{(YP + PV)}$$

$$K = \frac{(PV + YP)}{511}$$

$$\tau_y = (5.11K)^n$$

$$R_A = \frac{\rho V_a^{(2-n)}(D_H - D_P)^n}{(2/3)G_{fn}K}$$

Concentration Based on ROP in Flow Channel

$$C_c = \frac{(V_r D_B^2/1471)}{(V_r D_B^2/1471) + Q_m}$$

Fluid Velocity Based on Open Flow Channel

$$V_a = \frac{24.5Q_m}{D_H^2 - D_P^2}$$

Coefficient of Drag around Sphere

If $R_e < 225$ then,

$$C_D = \frac{22}{\sqrt{R_a}}$$

else,

$$C_D = 1.5$$

Mud carrying capacity

$$C_M = \frac{4g\left(\frac{D_c}{12}\right)(\rho_c - \rho)}{3\rho C_D}$$

Slip Velocity

If $V_A < 53.0$, then $V_{SV} = (0.00516)V_A + 3.0006$

If $V_A \geq 53.0$, then $V_{SV} = (0.02554)(V_A - 53.0) + 3.28$

Settling Velocity in the Plug in a Mud with a Yield Stress

$$U_p = \left[\frac{4}{3}\frac{gD_c^{1+bn}(\rho_c - \rho}{aK_b\rho_c^{1-b}}\right]^{\frac{1}{2-b(2-n)}}$$

Where:

$$a = 42.9 - 23.9n$$

$$b = 1 - 0.33n$$

Angle of Inclination Correction Factor

$$C_a = (\sin(1.33\alpha))^{1.33}\left(\frac{5}{D_H}\right)^{0.65}$$

Cuttings Size Correction Factor

$$C_s = 1.286 - 1.04D_c$$

Mud Weight Correction Factor

If $(\rho < 7.7)$,then

$$C_m = 1.0$$

else

$$C_m = 1.0 - 0.0333(\rho - 7.7)$$

Critical Wall Shear Stress

$$\tau wc = [ag\sin(\alpha)(\rho c - \rho)Dc^{1+b}\rho^{b/2}]\frac{2n}{2n - 2b + bn}$$

Where:

a = 1.732

b = -0.744

Critical Pressure Gradient

$$Pgc = \frac{2\tau wc}{r_h[1-(\frac{rp}{r_h})^2]}$$

Total Cross Sectional Area of the Annulus without Cuttings Bed

$$A_A = \frac{\pi}{4}\frac{(D_H^2 - D_P^2)}{144}$$

Dimensionless Flow Rate

$$\Pi g_b = \Pi[8 \times \frac{\frac{n}{2(1+2n)}}{(a)\frac{1}{b}}]^{\frac{1}{2-(2-n)b}} \times (1-(\frac{r_p}{r_h})^2)(1-(\frac{r_p}{r_h})^{\frac{b}{2-(2-n)b}}]$$

Where:

a = 16

b = 1

Critical Flow Rate (CFR)

$$Q_{crit} = \pi h^2 \left[\frac{\rho g b^{\frac{1}{b}} r_h^{\left(\frac{1}{b+n}\right)}}{K \rho^{\left(\frac{1}{b-1}\right)}} \right]^{\frac{b}{2-b(2-n)}} \Pi_{gb}$$

Correction Factor for Cuttings Concentration

$$C_{BED} = 0.97 - (0.00231\ \mu_a)$$

Cuttings Concentration for a Stationary Bed by Volume

$$C_{bed} = C_{BED}\left(1.0 - \frac{Q_m}{Q_{crit}}\right)(1.0 - \phi_B)(100)$$

Where:

D_B = Bit diameter

D_H = Annulus diameter

D_P = Pipe diameter

D_{TJ} = Tool joint diameter

D_C = Cuttings diameter

τ_y = Mud yield stress

G_{pb} = Power law geometry factor

R_A = Reynolds number

R_e = Particle Reynolds number

ρ = Fluid density

ρ_c = Cuttings density

Surge and Swab Calculations

The Swab/Surge model calculates the annulus pressures caused by the annular drilling fluid flow induced due to the movement of the string. During tripping operations, the pressures throughout the well will increase or decrease depending on whether the workstring is being lowered or raised.

A pressure increase due to a downward pipe movement is called a surge pressure, whereas the pressure increase due to an upward pipe movement is called the swab pressure.

The swab/surge calculations do not model fluid wave propagation or consider gel strength of the mud.

$$V_{trip} = \frac{L_{stand}}{T_{trip}}$$

If the pipe closed, then $Q_{pipe} = 0.0$

If the pipe is open and the pumps off, then

$$A_{ratio} = \frac{A_{open}}{(A_{open} + A_{ann})}$$

$$Q_{pipe} = (V_{trip})(A_{closed} - A_{open})(A_{ratio})$$

If there is a surge situation, then Q_{pipe} is negative (up the string).

If there is a swab situation, then Q_{pipe} is positive (down the string).

If the pipe is open, and the pumps are on then,

$$Q_{pipe} = Q_{rate}$$

The flow rate induced by the pipe movement is:

$$Q_{induce} = V_{trip} A_{closed}$$

If there is a surge situation, then Q_{induce} is positive (up the annulus).

If there is a swab situation, then Q_{induce} is negative (down the annulus).

$$Q_{ann} = Q_{induce} + Q_{pipe}$$

The annular flow rate, Q_{ann} , is then used to perform frictional pressure loss calculations to determine the annulus pressure profile.

If the first component is a bit then,

$$A_{open} = A_{TFA}$$

$$A_{closed} = \frac{\pi}{4}\left(OD_{bit}\right)^2$$

If the first component is not a bit then,

$$A_{open} = \frac{\pi}{4}\left(ID_{pipe}\right)^2$$

$$A_{closed} = \frac{\pi}{4}\left(OD_{pipe}\right)^2$$

Where:

V_{trip} = Trip velocity

L_{stand} = Stand length

V_{trip} = Trip time per stand

Q_{pipe} = Pipe flow rate

Q_{induce} = Flow rate induced by pipe movement

Q_{rate} = Pump flow rate

Q_{ann} = Annular flow rate

A_{closed} = Pipe closed area

A_{open} = Pipe open area

A_{ratio} = Ratio of pipe open area to combined pipe and annulus open area

A_{TFA} = Bit total flow area, TFA

Maximum Back reaming rate

$$BR\max = ROP\max\left(\frac{Qcrit \mid DP}{(Qcrit \mid DP - Qmud)}\right)$$

Where:

$BR\max$ = Maximum backreaming rate (ft/hr)

$ROP\max$ = Maximum rate of penetration (ft/hr)

$Qcrit$ = Critical flow rate (gpm)

$Qmud$ = Mud flow rate (gpm)

DC = Drill collar ID (in)

DP = Drill pipe ID (in)

ECD Calculations

$$ECD = \frac{P_h + P_f}{.052\left(D_{tvd}\right)}$$

$$P_h = .052\,(W_{mud}\,D_{tvd})$$

$$P_f = \sum \frac{\Delta P}{\Delta L}\left(\Delta D_{md}\right)$$

Where:

ECD = Equivalent circulating density, (ppg)

W_{mud} = Fluid weight, (ppg)

P_h = Hydrostatic pressure change to ECD point. (psi)

P_f = Frictional pressure change to ECD point (psi)

$\frac{\Delta P}{\Delta L}$ = Change in pressure per length along the annulus section (psi/ft).

This is a function of the pressure loss model chosen.

D_{tvd} = True vertical depth of point of interest, (ft)

ΔD_{md} = Annulus section length (ft)

0.052 = conversion constant from (ppg)(ft) to psi

Appendix D – Well Path

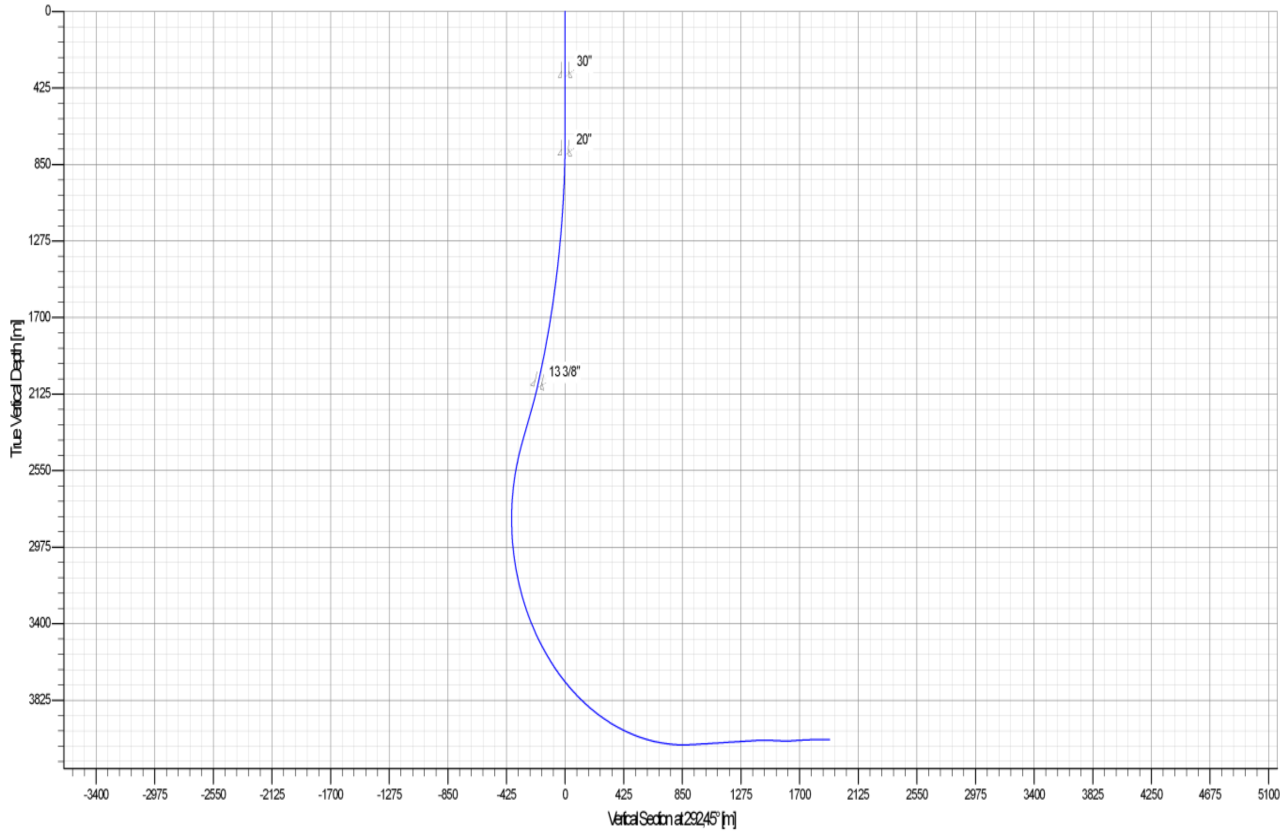


Figure 12: SS1-H Sidetrack wellpath

Appendix E – BHA

String Initialization

String Name: 12,5" Assembly

String (MD): 4313,00 m Specify: Top to Bottom Import String

Library: Export Import

	Section Type	Length (m)	Measured Depth (m)	OD (mm)	ID (mm)	Weight (kg/m)	Item Description
1	Drill Pipe	4187,001	4187,00	139,70	121,36	39,18	Drill Pipe 5 1/2 in, 21.90 ppf, S, FH, P
2	Heavy Weight	54,000	4241,00	168,28	114,30	109,38	Heavy Weight Drill Pipe Grant Prideco - Spiral, 6 5/8 in, 73.50 ppf
3	Sub	2,000	4243,00	201,17	76,20	218,76	Cross Over 8, 8 x3 in
4	Drill Collar	9,500	4252,50	203,20	76,20	238,40	Drill Collar 8 in, 2 in, 6 5/8 REG
5	Jar	9,500	4262,00	203,20	63,50	229,71	Hydraulic Jar Eastman Hyd., 8 in
6	Drill Collar	9,500	4271,50	203,20	76,20	238,40	Drill Collar 8 in, 2 in, 6 5/8 REG
7	Stabilizer	2,000	4273,50	203,20	76,20	218,77	Integral Blade Stabilizer 11" FG, 8 x3 in
8	MWD	17,800	4291,30	209,55	76,20	218,77	MWD Tool, 8,250 in, 147,01 ppf, 15-15LC MOD (1), 6 5/8 REG
9	Stabilizer	2,000	4293,30	215,90	76,20	251,59	Near Bit Stabilizer 12 1/4" FG, 8 1/2 x3 in
10	Mud Motor	14,944	4308,24	244,47	148,59	232,29	Bent Housing 9 5/8 Sperry, 9 5/8 x5.85 in
11	Mud Motor	4,450	4312,69	228,60	113,40	240,67	Steerable Motor RSS PowerDrive, 9 5/8 x5.85 in in
12	Bit	0,305	4313,00	311,15		397,34	Tri-Cone Bit, 1,200 in²

Figure 13: 12.25" Drill string assembly details

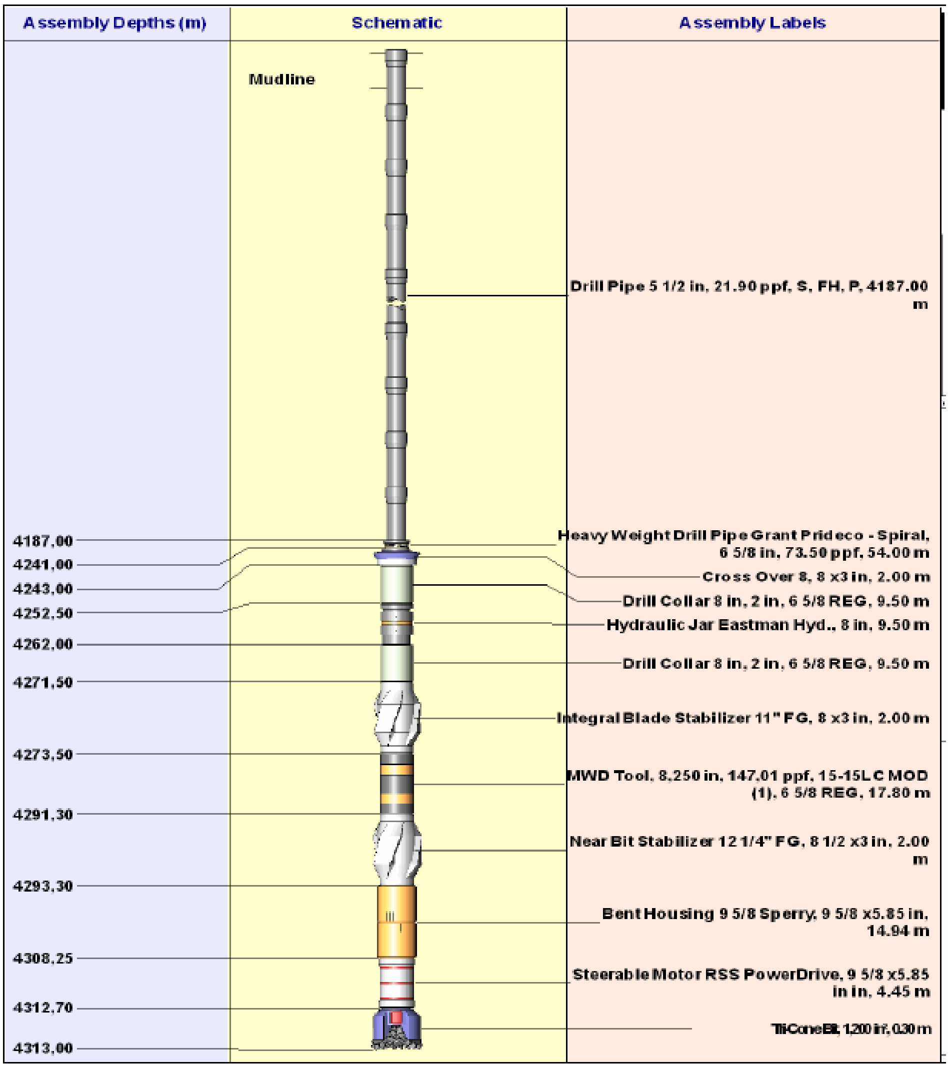


Figure 14: 12.25" Drill string schematic

Appendix F – Pressure Prognosis

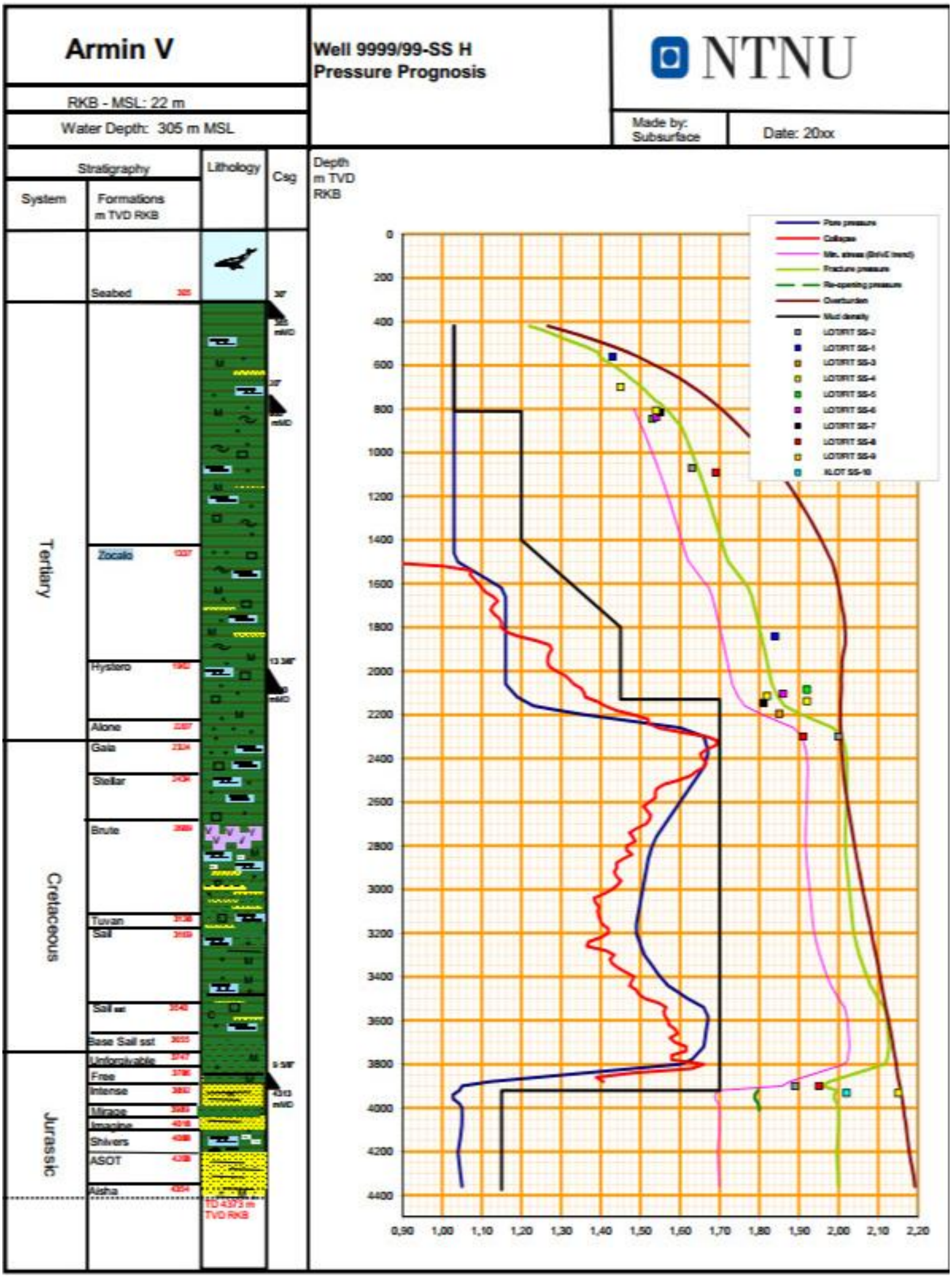


Figure 15: Armin V Pressure prognosis

Appendix G – Torque and Drag

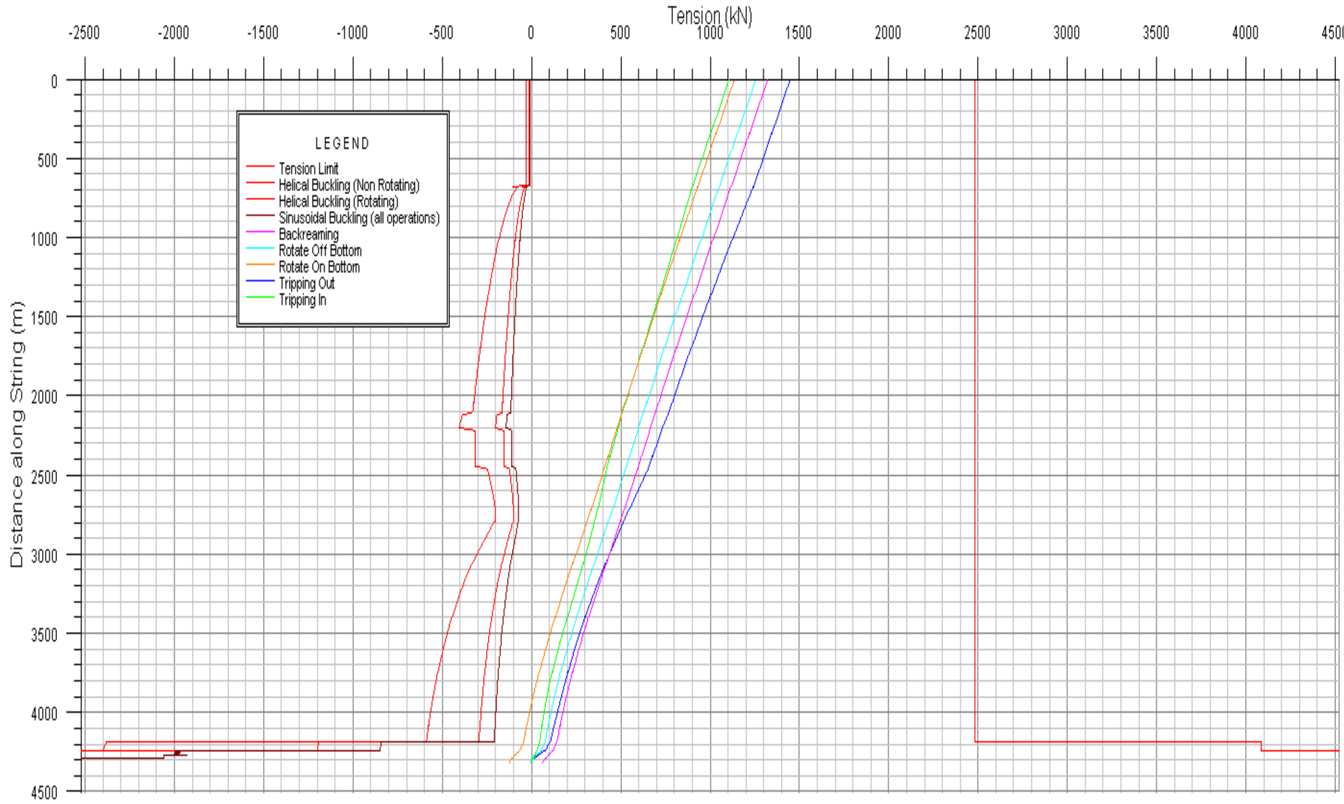


Figure 16: Effective Tension Graph

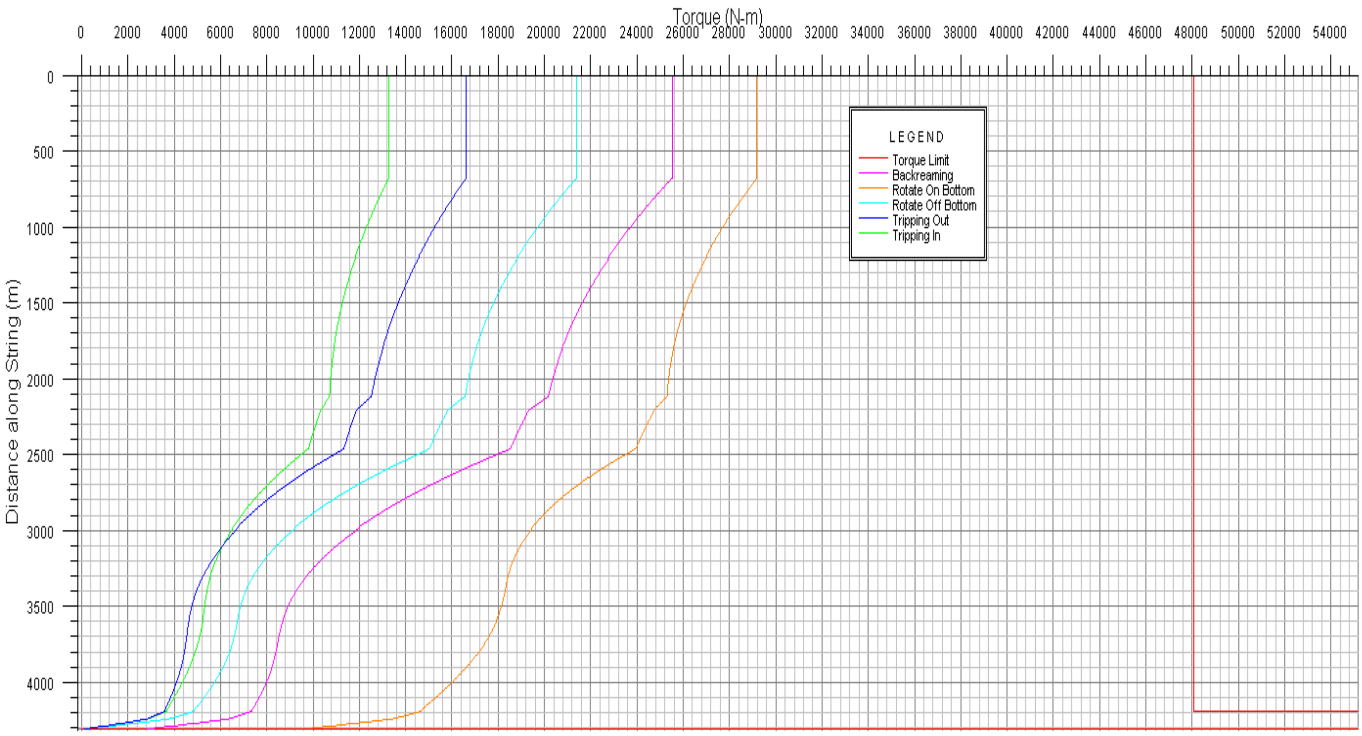


Figure 17: Torque Graph

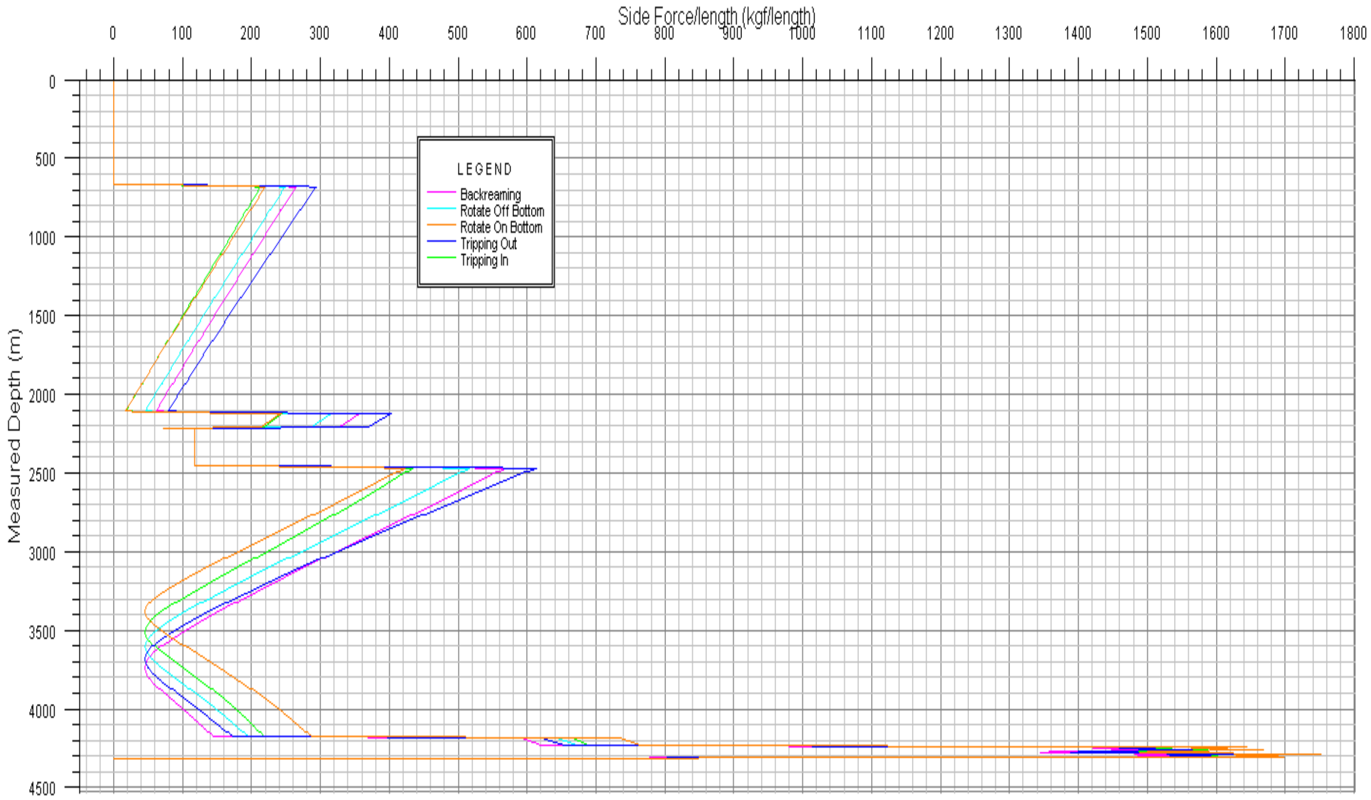


Figure 18: Side Force Graph

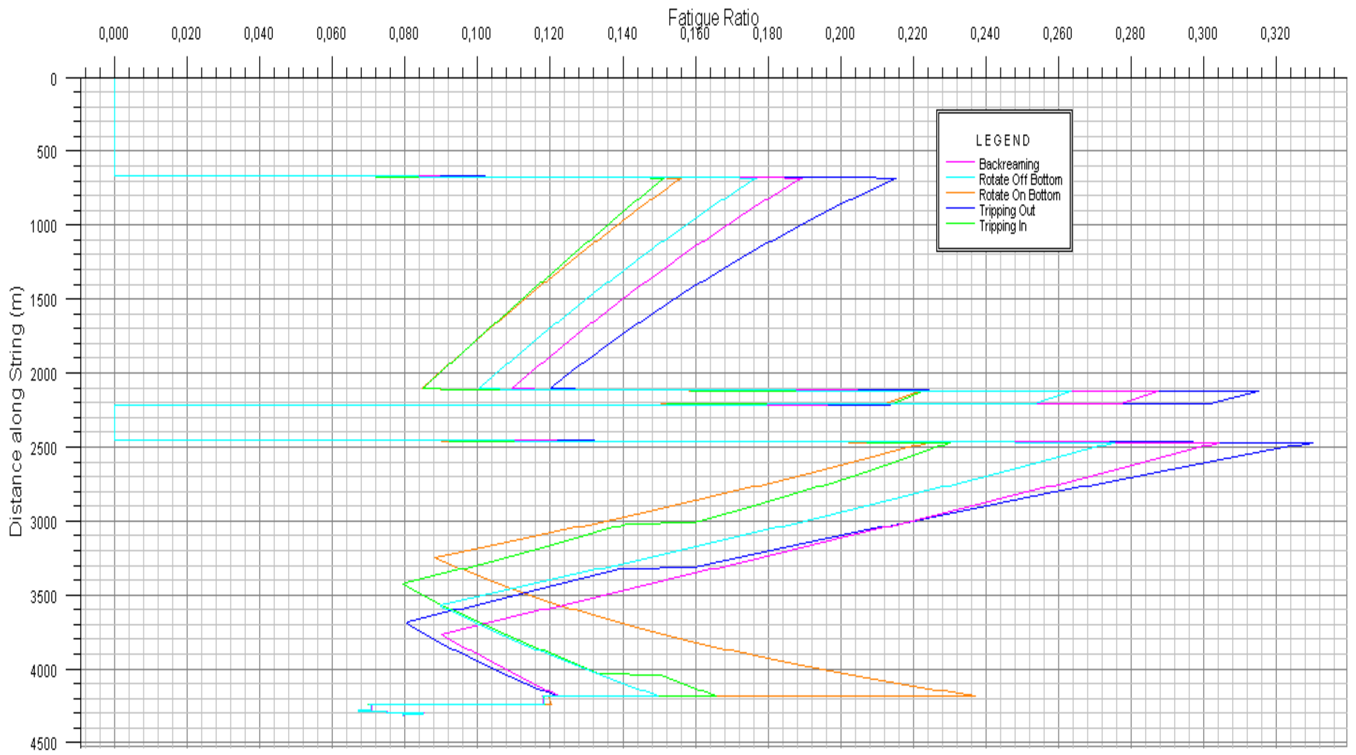


Figure 19: Fatigue Ratio

Appendix H – Hydraulics

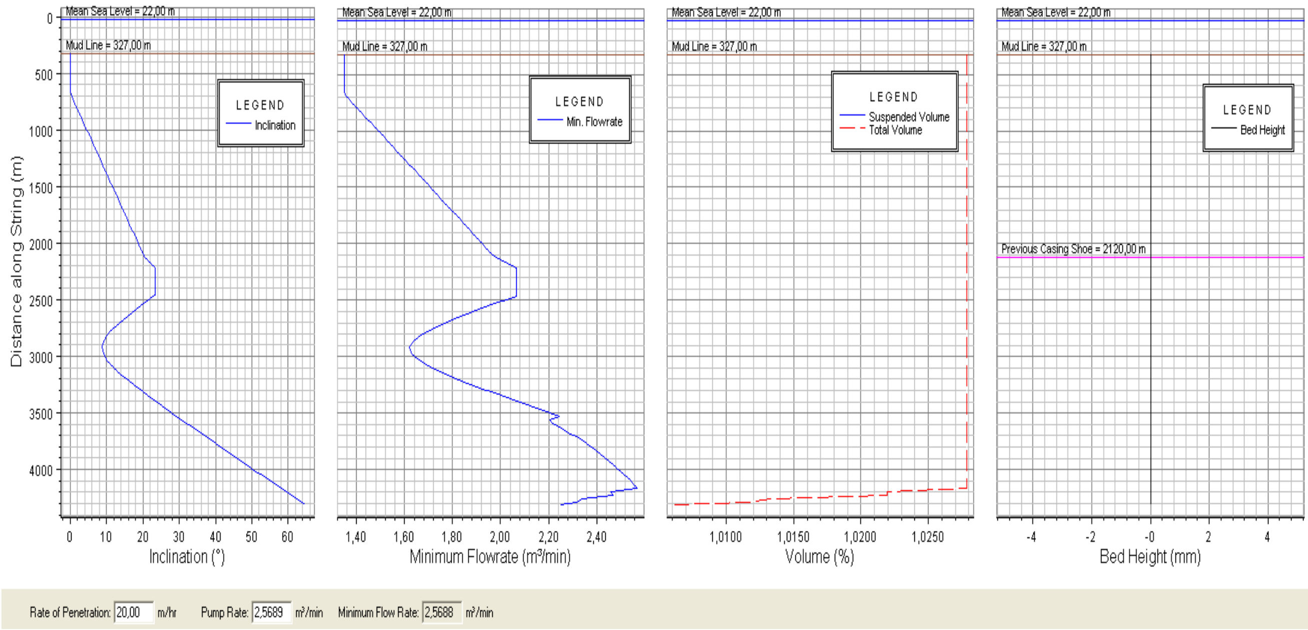


Figure 20: Operational Cuttings Transport

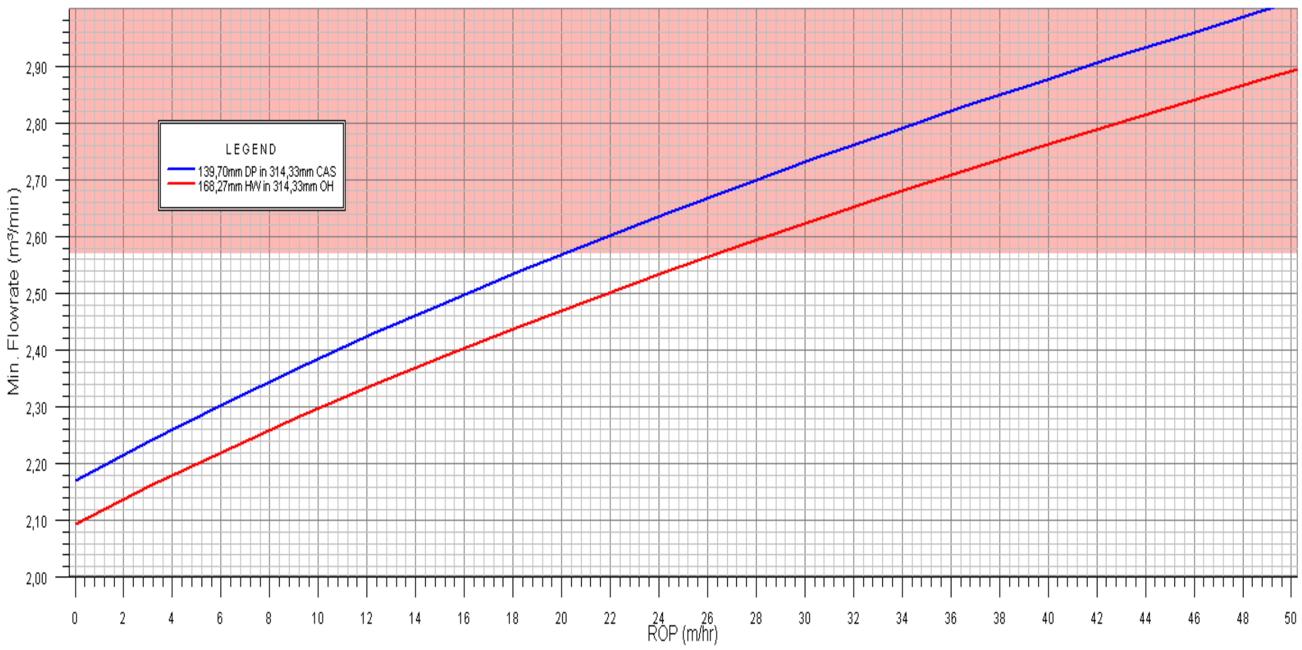


Figure 21: ROP v Minimum flow rate

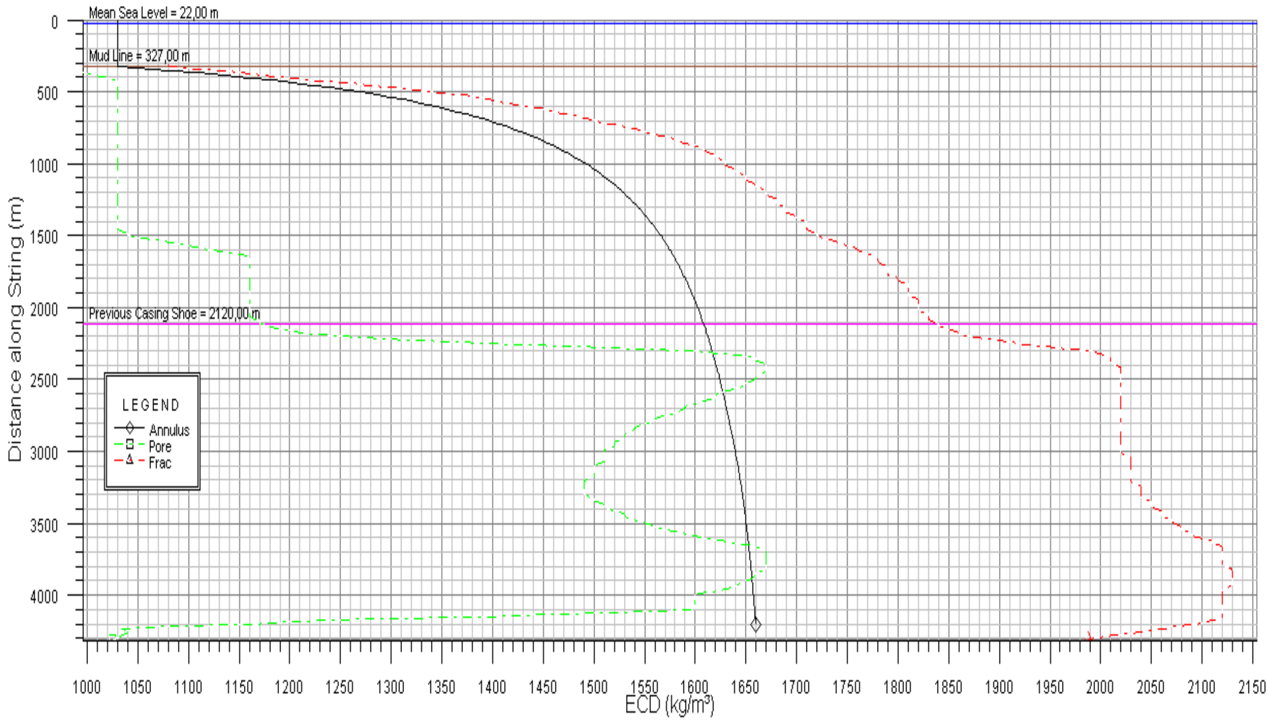


Figure 22: ECD v Depth with initial Mud Weight

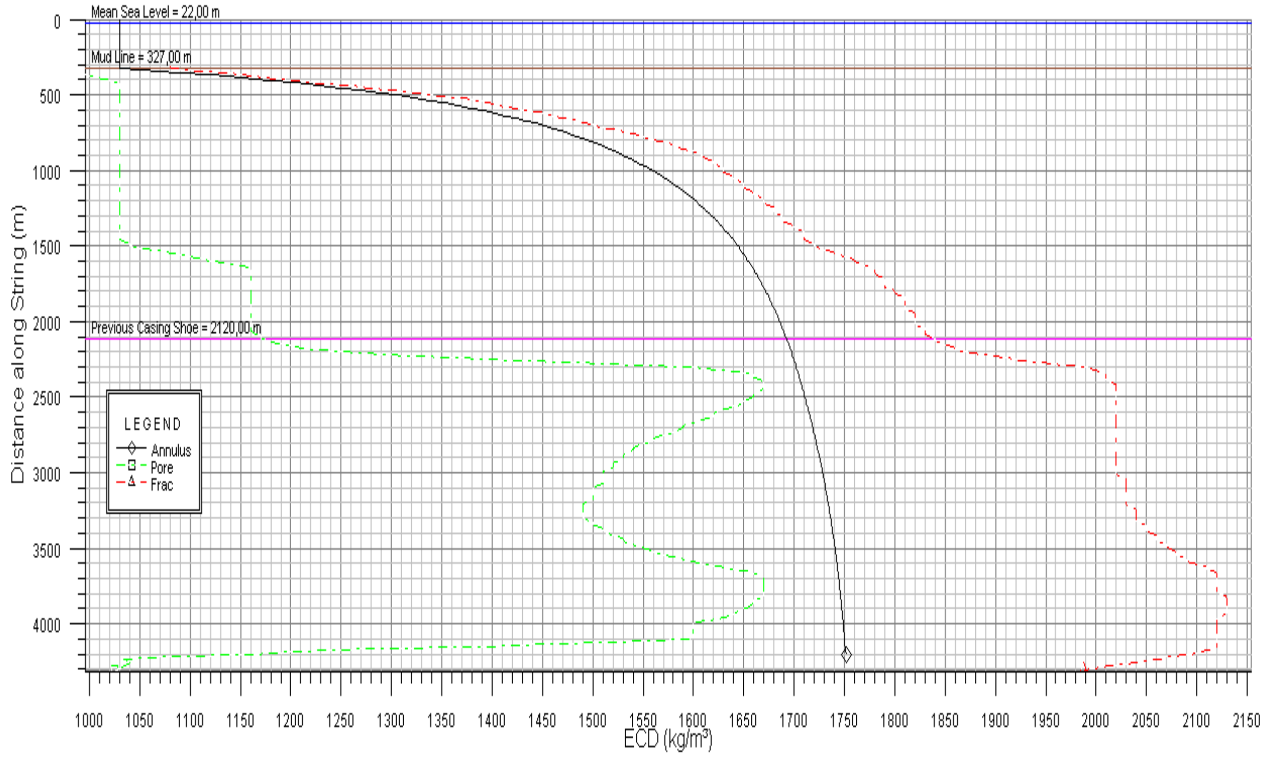


Figure 23: ECD v Depth with increased Mud Weight

Appendix I – Anti collision summary

NTNU

Anticollision Summary Report

Company:	Company	**Local Co-ordinate Reference:**	Site Site TPG4525 2015
Project:	SS H Template	**TVD Reference:**	Subsea @ 22,00m
Reference Site:	Site TPG4525 2015	**MD Reference:**	Subsea @ 22,00m
Site Error:	0,00 m	**North Reference:**	Grid
Reference Well:	SS 1 H	**Survey Calculation Method:**	Minimum Curvature
Well Error:	0,00 m	**Output errors are at**	2,00 sigma
Reference Wellbore	Wellbore #2	**Database:**	EDM 5000.1 Single User Db
Reference Design:	sidetrack	**Offset TVD Reference:**	Offset Datum

Reference	sidetrack		
Filter type:	NO GLOBAL FILTER: Using user defined selection & filtering criteria		
Interpolation Method:	MD Interval 30,48m	**Error Model:**	ISCWSA
Depth Range:	2 120,00 to 5 000,00m	**Scan Method:**	Closest Approach 3D
Results Limited by:	Maximum center-center distance of 3 048,00 m	**Error Surface:**	Elliptical Conic
Warning Levels Evaluated at:	2,00 **Sigma**	**Casing Method:**	Not applied

Survey Tool Program **Date** 16.06.2016

From (m)	To (m)	Survey (Wellbore)	Tool Name	Description
0,00	5 968,54	sidetrack (Wellbore #2)	Magn, std, mag-corr, dual inc	Magnetic Tools (MWD, EMS)

Summary

Site Name Offset Well - Wellbore - Design	Reference Measured Depth (m)	Offset Measured Depth (m)	Distance Between Centres (m)	Distance Between Ellipses (m)	Separation Factor	Warning
Site TPG4525 2015						
SS 1 H - Wellbore #1 - Design #2	2 120,00	2 121,76	17,02	10,94	2,800	CC
SS 1 H - Wellbore #1 - Design #2	5 000,00	4 911,29	18,47	8,44	1,842	ES, SF
SS 2 H - Wellbore #1 - Sidetracked design	4 971,81	4 408,48	10,10	-65,76	0,133	Level 1, CC
SS 2 H - Wellbore #1 - Sidetracked design	4 985,12	4 421,03	11,08	-79,99	0,122	Level 1, ES, SF
SS 2 H - Wellbore #2 - Design #1	2 120,00	2 057,43	349,16	332,19	20,566	CC, ES
SS 2 H - Wellbore #2 - Design #1	5 000,00	5 365,65	1 180,91	1 037,84	8,254	SF
SS 3 H - Wellbore #3 - Design #1	2 120,00	2 091,90	233,36	212,61	11,249	CC, ES
SS 3 H - Wellbore #3 - Design #1	2 668,64	2 733,70	408,27	371,28	11,039	SF
SS 4 H - Wellbore #4 - Design #1	2 120,00	2 116,87	127,04	109,48	7,238	CC, ES, SF
SS-5 H - Student Group Injector - Design #2	2 120,00	2 031,38	363,54	348,96	24,928	CC, ES
SS-5 H - Student Group Injector - Design #2	4 375,52	3 923,49	507,10	474,77	15,689	SF