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# MASTER'S THESIS

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## Summary

Extended reach drilling is the result of industry focus to exploit fields efficiently with a minimum financial and environmental impact. Two of the ERD pioneer fields are Wytch Farm in UK and Statfjord on the Norwegian Continental Shelf. These two fields have contributed largely to the development and evolution of ERD technology and methods. ERD technology have been used to increase the drainage radius for platforms, which resulted in fewer offshore platforms in the development and a large cost saving.

Throughout the three last decades, technology have been rapidly improved towards what seems to be the limit of the conventional drilling method and technology in terms of the wells reach. The first well to break the 10 km mark was M11 at Wytch Farm in 1997. In 2013, the Z-42 was drilled on the Sakhalin Project and is with its horizontal reach of 11.7 km the world's longest ERD well. This shows that the evolution of technology and methods have not contributed largely in increasing the maximum reach over the last decade, but the reliability and cost of equipment and operation have been greatly improved.

Limiters in ERD are elaborated in this thesis along with simple examples used to illustrate the different challenges associated with the limiting factor. Two different available technologies that can reduce impact from limiting factors are presented to show that it is possible to increase drilling efficiency with only adding one new tool.

The Hole in One Producer concept presents a new method of drilling and completing ERD wells and is thought to have a potential reach of 20 km. The concept is still in the conceptual stage and some of the technical and operational challenges are presented along with the technology qualification phase. The success of this concept is dependent on developing new technology and is therefore associated with a large financial and operational risk.

A cost comparison of the HOP concept and a subsea development shows that the HOP is approximately three times as expensive as the subsea solution. Subsea solutions is a regular operation on the NCS and are not associated with large financial risk, this is a challenge for the commercialization of the HOP concept. Identified potential areas for the HOP concept are environmental sensitive areas where conventional technology is not applicable and the use of HOP traction unit to deploy completion and pulling objects from the well.

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# Nomenclature

| | |
|---|---|
| AST | Anti Stick-slip tool |
| BOP | Blow Out Preventer |
| BOPD | Barrels of Oil Per Day |
| BHA | Bottom Hole Assembly |
| CFR | Critical Flow Rate |
| ECD | Equivalent Circulation Density |
| EMM | Electrical Magnetic Multishot |
| ERD | Extended Reach Drilling |
| FMECA | Failure mode, Effect and Criticality Analysis |
| FTA | Fault Three Analysis |
| ft | Feet |
| GPM | Gallons Per Minute |
| HAZOP | Hazard and Operability |
| HVGS | Highly Variable Gauge Stabilizer |
| HOP | Hole in One Producer |
| HD | Horizontal Displacement |
| HSE | Health, Safety and Environmental |
| ID | Inner Diameter |
| in. | Inch |
| IPDM | Instrumented steerable Positive Displacement Motor |
| IDAs | Intelligent Drilling Advisory System |
| LWD | Logging While Drilling |
| LCM | Lost Circulation Material |
| MPD | Manage Pressure Drilling |
| MD | Measured Depth |
| MWD | Measurement While Drilling |
| m | meter |
| MNOK | Million Norwegian Kroner |
| MSE | Mechanical Specific Energy |
| NAF | Non-Aqueous Fluid |
| NCS | Norwegian Continental Shelf |
| NPT | Non Productive Time |
| OD | Outer Diameter |
| OBM | Oil Based Mud |
| OWC | Oil Water Contact |
| OWR | Oil Water Ratio |
| PDC | Polycrystalline Diamond Compact |
| psi | Pounds per Square Inch |
| ROP | Rate Of Penetration |
| RPM | Revolutions Per Minute |
| Re | Reynolds number |
| RSS | Rotary Steerable System |
| sg | Specific Gravity |

| | |
|---|---|
| TD | Target Depth |
| TRL | Technology Readiness Level |
| TVD | True Vertical Depth |
| UBD | Under Balanced Drilling |
| UK | United Kingdom |
| WBM | Water Based Mud |
| WOB | Weight On Bit |
| WF | Wytch Farm |

# 1 Introduction

The cost on the Norwegian Continental Shelf (NCS) have increased over the last years and together with the maturity of the shelf, this challenges the profitability of projects and companies. Minister of Petroleum and Energy Tord Lien states that "*we must develop knowledge, innovation and new technology. Then, and only then, will we be equipped for the future*"(Ministry of Petroleum and Energy 2014).

The mature areas on the NCS are characterized by known geology and well-developed or planned infrastructure, and this is most parts of the North Sea, Halten Bank, surrounding areas of Ormen Lange, Snøhvit and Goliat. In these areas, it is likely to discover hydrocarbons, but large discoveries are less likely. Smaller discoveries are less likely to justify an independent infrastructure development and calls for a cost-efficient development. Over the last decades, some of these small discoveries have been developed using a subsea tie-in solution or drilling extended reach wells. These solutions increase the field profitability and lifetime (Ministry of Petroleum and Energy 2014, Statoil 2014).

Extended reach drilling (ERD) is one method for achieving a cost-efficient drainage of the field. The longer wells have more reservoir exposure, can access remote parts of the field and effectively drain a field, which often have irregular geometry. ERD can reduce the number of wells need and can reduce number of installation on one field (H. Blikra 1994).

New and innovative technologies are important for achieving optimal and environmentally friendly hydrocarbon recovery on NCS and as stated by Tord Lien, very important in order to be prepared for future challenges. Reelwell is one of the companies that are currently providing a new and innovative drilling solution (M.A. Belarde 2011, O. Vestavik 2013). Hole in One Producer (HOP) is a new drilling and completion concept under development at IRIS(B.Aas 2008).

This thesis presents extended reach drilling and the associated limiting factors for long reach wells. The HOP concept is evaluated to identify advantages and challenges in the development phase. The technology qualification process is presented to highlight the main steps.

Chapter two presents the history of ERD and its successful impact on the Statfjord and Wytch Farm field development along side with encountered challenges.

Chapter three presents the limitations of conventional drilling and challenges met during ERD drilling on the Sakhalin project, which contain many of the longest wells in the world. Example cases with calculations are shown to illustrate different challenges and technologies that can reduce these challenges are presented.

Chapter four elaborate on the Hole in One Producer concept, its function, application, challenges and how the technology qualification process is.

Chapter five presents a cost estimation comparison between a HOP well and a subsea tie-in solution.

Chapter six review the HOP concept and discuss the related advantages and challenges, in addition to discuss the used of HOP instead of a conventional solution.

# 2 Extended Reach Drilling

Oil and gas field discovered often have an irregular shape where reaching the remote parts of the reservoir and small remote independent reservoirs stretch the limit of novel technology. Challenges related to an effective drainage strategy have been one of the driving factors for extended reach drilling (ERD). An extended reach well is a well with a horizontal displacement to vertical depth ratio (HD/TVD) greater than 2.0 (Schlumberger 2014).

ERD wells can have different objectives as the long reach makes it possible to access remotely located reservoirs or expose large reservoir sections. This increases the efficiency of one single platform as the effective drainage area is increased. As a result the field can be developed utilizing fewer installations. With the conventional ERD technology available today the Statfjord and Gullfaks development would be done with one platform instead of three (B.S. Aadnøy 2006).

The ERD application is also applicable for prospects that earlier where deemed uneconomical or inaccessible of different reasons possible. Fields can be deemed inaccessible due to the environmental impact a drilling rig or platform will induce to the area. ERD technology can be used to drain offshore reservoirs that are located near shore. Professor Bernt Sigve Aadnøy presented the idea of exploiting the potential reservoirs located in Nordland VI and Nordland VII located outside Lofoten and Vesterålen in Northern Norway, by using the future ERD wells with a horizontal reach of 20,000 m. In this way the sensitive aquaculture will be of less impact (B.S. Aadnøy 2006, IRIS 2009, O. Vestavik 2013).

Onshore drilling to drain near shore reservoirs are a known application of the ERD technology and one of the most know fields are the Wytch Farm. In 1974, Wytch Farm (WF) were discovered close to the UK coastline southwest of London. This project was developed with an onshore drilling facility which achieved great success by utilizing ERD. WF is elaborated in the next section, as this is one of the most important fields for ERD development.

Statoil was one of several operating companies that have been the driving force for ERD development, especially on the Statfjord field. The experience from the couple first ERD wells in the Statfjord field will later be elaborated. Results from these successfully drilled wells were the reason for the change in Sleipner West development plan. Initially this field was planned developed with two platforms, each with a 5000 m drainage radius, but experience from Statfjord proved that larger drainage radius where possible. The new plan resulted in one platform with 7000 m drainage radius and one subsea development and a sub sequentially large cost benefit (H. Blikra 1994).

Today the evolution of ERD have reached the apparent limit with the available conventional equipment, with the world record well Z-42, having a horizontal reach of 11,739 m and measured depth (MD) of 12,700 m (V.P.Gupta 2014). This well were drilled from shore to the Chayvo field located in Sakhalin-1 project, comprising of several fields located on the East coast of the Sakhalin Island, Russia. As of October 2013, 16 of the 20 longest ERD wells are drilled here. Maersk Oil Qatar drilled in 2008 the former world record well BD-04A with a horizontal reach of 10,903 m and MD of 12,290 m (K. Sonowal 2009). The well is located offshore Qatar in the Al-Shaheen field.

As earlier stated the conventional equipment has apparently reached a limit due to the challenges with torque, drag, wellbore stability and completion. The most sensitive parts with respect to torque is the top drive and drill pipe connection limitation. Maersk Oil Qatar where able to reach their target depth

(TD) for well BD-04A by using a tapered drill string of 4" X 5" drill pipe which increased the torque limit for drill pipe connection and relocated the limiting factor to the top drive.

When drilling shallow long reach wells the majority of the drill string will be in contact with the low side of the previously set casing and the open hole, this introduces large torque and drag forces which are highly affected by the friction factor. The importance of good hole cleaning, mud characteristics and well profile is therefore clear (B.S. Aadnøy 1998, A. Hjelle 2006). For these shallow long reach wells the limiting factor are torque and drag, while for the deep long reach wells the limiting factor will be the rigs hoisting capability. This will be shown in an example in chapter 3.

In Norway, innovative companies develop solutions that will further push the horizontal reach limit to a new level. Reelwell states that their technology has the potential to drill 16,000 m long wells. To achieve the target they have developed a concept that consists of a dual aluminum string with a heavy over light fluid column in the annulus. In addition they utilize managed pressure drilling technology (O. Vestavik 2013). Hole in One Producer (HOP) are also using a dual string in their design but in addition, this concept include drilling and completion of the well in one run. (IRIS 2009). The HOP concept is further studied in chapter 4 and 5.

## 2.1 Wytch Farm

The BP operated field Wytch farm is Western Europe's largest onshore oil facility and is located in Dorset southwest of London, England. The ERD project at WF drains the Sherwood reservoir, which extends eastwards under Pool Bay at 1600 m depth. The development is located in an environmental sensitive area and feature among other a World Heritage Coastline and National Nature Reserves. Therefore the environmental aspect has been of great importance and the development where subjected to strict rules to regulate noise and pollution (BP 2014).

The initial development plan was to construct an artificial island in the bay to access the remote parts of the Sherwood reservoir. In December 1991, based the industry advancement in ERD the initial plan for development where abandoned. Instead a solution which utilized ERD from an onshore drilling facility where pursued. The underlying assumption for the abandonment was that long reach wells could have a 6000 m horizontal reach when drilled in the shallow Sherwood reservoir (D.A.Cocking 1997).

To illustrate the economic benefit of pursuing the ERD solution, by avoid constructing an artificial island there was an expected cost saving of $150 million and in addition, the field could start producing three years earlier. After production started from the first three ERD wells, the field production increased from 68,000 BOPD to 90,000 BOPD (M.L. Payne 1994).

The project has proven to be a great success both for BP and for the technology development in the industry. Experience gained during this projected was continuously used to improve the design of the next well to be drilled and to further push the limits of available drilling equipment and techniques. BP developed a global ERD network within the company and organized workshops for all involved personnel before each well to highlight areas of improvement and challenges. The group effort eventually culminated in setting the world record when breaking the 10,000 m horizontal reach limit in 1997 with the well M11. Then, one year was used for planning the next record breaking well M16 which was drilled to a reach of 10,728 m in 1999 (T. Meader 2000). The evolution of ERD is clearly shown when comparing the achievements from project start in 1993 with well F18 reaching a departure of 3856 m and the M16 in 1999.

### 2.1.1 Challenges encountered at Wytch Farm

This section will elaborate on challenges met in the project from the start in 1993 and following the development up to 1999.

A paper presented in 1994 (M.L. Payne 1994) describe the experience gained from drilling the first couple of ERD wells, F18-F21 located on the existing F-site. The largest main challenges encountered for these wells are related to torque and drag, hole cleaning, casing placement and wellbore stability. The project was associated with much uncertainty and concerns of how to use known and available technology in longer and more inclined wells. Because of this, the first well was drilled using a build and hold profile, where the observed torque behavior was not beneficial and for later wells a modified catenary profile was chosen as standard. Advantages with modified catenary profile are reduction in torque and increase in tubular running length compared to initial well profile. During drilling the string is subjected to contact forces from both the wellbore wall and the mud, hence a mud composition that lubricate is important. The field experience from 12 ¼” showed good correlation between mud lubricity prediction and observed behavior, while in the 8 ½” this was no longer the case. Much higher torque was observed during drilling with the low-weight OBM and later studies showed that the additives used to lubricate in fact had low impact on the mud lubricity. The study showed that the important factor was the oil water ratio (OWR), and after applying higher OWR to the OBM at later 8 ½” sections the torque was reduced.

For the first wells the drill string was torque limited by the tool joints, but based on research the engineers identified a high friction tread-compound which could increase the 5” drill pipe make-up torque with 27%. An increase of 20% were shown on the drill pipe in well F20, and on later wells the torque limit were further increased by using stress balancing and the high friction tread-compound. The benefit was that the torsional capacity of the drill string exceeded the top drive torsional capacity. Progress in drill pipe technology showed that double shouldered tool joints could address some of the torque challenges encountered in the 12 ¼” and 8 ½” section. Thus, new pipe were acquired and implemented in the equipment portfolio from ERD well five.

WF had the advantage of multiple offset wells, which were used to establish a forecast of the in-situ stresses. The experience from 12 ¼” section was that the mud weight needed to be 1.25 sg, which was the maximum mud weight forecast. The section is drilled through mainly mudstone down to the Sherwood reservoir. A benefit of sealing of the mudstone before entering the reservoir was that the weight used in the 8 ½” section was lower than forecasted.

Hole cleaning was an issue for the 8 ½” section as the lower flowrate and mud weight was incapable of suspending and transport the cuttings to surface without creating cutting dunes which increased the drilling torque. Due to the frequently incidents of loss circulation in the reservoir section the mud rheology had to be kept at a minimum to maintain the necessary low ECD. No clear solution to the hole cleaning problem was identified, instead it was carefully monitored and high torques was planned for the wells.

The 12 ½” section is completed with a 9 5/8” casing which was successfully placed using circulation every 750-1000m, with only some mechanical resistance issues which was resolved by circulation. Top drive manipulation was used as a contingency procedure for the casing placement, involving the opportunity to rotate, circulate, reciprocate and compress. The completion is based on a cemented and perforated 5 ½” liner, which is rotated to bottom. Placement and cementation of the liners have been successfully performed, but unaddressed torque was observed during cement displacement in annulus.

A new drilling location called M-site was constructed to better access the offshore resources after drilling the first four from the existing F-site. In 1997 a paper was presented (D.A.Cocking 1997) about experience from the first wells drilled on this location and new equipment and techniques employed in well M6 to M9. One major change has been made in the well trajectory for these wells, as they are placed in the upper part of the reservoir to delay water-breakthrough by increasing the standoff to OWC. This section of the reservoir is known to have a low productivity and therefore a longer reservoir section is required to achieve good production. Due to the known fact that the productivity at the heel of the well is higher than at the toe, it was decided to postpone perforation of the heel section until water breakthrough at the toe. The longer 8 ½” sections was drilled using instrumented steerable positive displacement motor (IPDM) and highly variable gauge stabilizer (HVGS) which allowed rotation of the string while steering and reduced sliding to a current minimum. Sliding was still needed to make changes in azimuth, immediate changes in inclination and when breaking through hard formation boundaries. One remarkable observation was made after a severe loss event in M2. The fibrous LCM created a filter cake when stopping the loss and in combination with the OBM, this reduced the friction between drill string and formation. This effect was utilized when slide drilling since the limit for torque and drag in clean holes in highly departed wells was reached. LCM pills was also used for hole cleaning, due to its ability to suspend and effectively transport large amount of cuttings out. The annular friction loss development was different the reservoir section compared to the F-site wells since they were longer and thus achieved a higher ECD. Sized calcium carbonate was added to OBM to create a sufficient filter cake that could withstand the increase in overpressure. However, this solution introduced new problems to the liner placement, since the liner centralizers became packed off with filter cake when rotated to TD. A new and more aggressive cleanup program was designed and mitigated the problem. Casing flotation was successfully performed on 9 5/8” casing in M3 and the lessoned learned is that the measured mud weight at surface should be lower than the calculated mud weight to reduce the positive buoyancy, in addition the rheology should be as low as possible to reduce the surge pressure when running the empty casing to TD.

With a decreasing oil prize in the late 1990 the focus changed towards cost reduction rather than technological achievements (T. Meader 2000). BP organized workshops for the involved personnel before each well to divide the process into operations and drill the well on paper. From 1996, a rotary steerable system (RSS) was implemented to reduce the axial drag induced from sliding and increase ROP. Results from M12 showed that RSS had approximately twice the ROP than steerable motor had on previous wells. The system had in the start a low availability due to bearing failure, but much improvement was early done on the mechanical performance of the tool. In M17 the RSS drilled 2000m of reservoir formation over two runs where the tools operated in 130 hours. Since tripping out and in from ERD wells can take up to 48 hours, the need of a bit that could last longer than the RSS became clear. Two different bits was identified in cooperation with the suppliers. Throughout the ERD project some main lessons learned have been made regarding torque and drag. The prediction of torque and drag is crucial to drill a successful well and to achieve this, data collection during drilling and from offset wells are important. The use of predicted hook load plot versus real time hook load during casing running is a good method to detect a problem on an early stage.

## 2.2 Statfjord Field

Statfjord field is located northwest of Bergen on the Norwegian/UK boundary, discovered in 1974 by Mobil Exploration Norway. Mobil developed and operated the field until 1987 when Statoil became the operator. The field is 24 kilometers long and on average 4 kilometers wide, extending over blocks on both sides, but 85% of the field is located on Norwegian sector. The two main reservoirs are the Brent Group and Statfjord Formation, which both have excellent reservoir quality and the oil accumulation trapped in tilted fault blocks. The field is developed by using three gravity-based-condeep platforms with a 5000 m separation. Platform positioning was based on the expectation that wells with a 60 degree sail section and a horizontal reach of 3000 meters would be possible to drill (S.A. Haugen 1988). Due to this limitation, the initial plan also included a later subsea development to drain the North Statfjord, which is separated from the main field by large faults. ERD was considered the only alternative to subsea development, where it was estimated that the ERD solution would cost one third of the subsea development. Well B40, drilled in 1988 with a horizontal reach of 4100 meters and showed that it could be possible to drill the necessary ERD wells to access the North Statfjord. With the motivation for large cost-savings, the knowledge from B40 and the experience from drilling 95 wells in the field, Statoil decided to drill the ERD well C10 to access the North Statfjord reservoir. The well was a success as it broke the ERD world record with a horizontal reach of 5003 m, later the world record was beaten again with C3 and C2 having a reach of respectively 6086 m and 7290 m (B. Rasmussen 1991, A. Njaerheim 1992, T.E. Alfsen 1995).

The Statfjord field geology introduces some drilling problems that proved to be challenging form the very beginning of the high angle drilling described in the development plan. The wells are predominately drilled through formations with large amounts of highly reactive clays and shale, with low compressive strength and abnormal pore pressure. The experience from exploration and approval drilling on the field was used to design the first casing program, which proved to be valid only for wells with an angle bellow 45 degree. Increasing the inclination above this point introduced drilling problems like excessive backreaming, poor hole cleaning, lost circulation and stuck pipe, predominately in the 17 ½” section. The casing program was change two more times before high angle wells were drilled with few problems. Experience from the high angle drilling start, showed that the 13 3/8” casing is the critical string to obtain formation integrity and that casings should be circulated down at an early stage since the wellbore is aggravated over time (R.C. Wilson 1986).

### 2.2.1 Challenges Encountered at Statfjord ERD Wells

The first ERD well was drilled in 1989 on Statfjord and the C10 culminated in a world record with 6200 m MD and a reach of 5003 m. However, the well was drilled through an unforeseen fault, penetrating Top Brent 40 m deeper than predicted, and into poor reservoir conditions resulting in a sidetrack and completion of the well closer to the platform. By utilizing the experience from offset wells the team managed to drill the well without encountering any major drilling problems. The original TD was reached after 54 days of drilling and the well was sidetracked and completed within planned time of 99 days. The minor incidents that were encountered will now be further elaborated. OBM was used in the 17 ½” and later sections to minimize the reaction between mud and formation. After reaching TD for the 17 ½” section there was an incident with tight hole during a bit trip and large amount of cuttings was seen over the shakers when circulating. It was concluded that the circulation rate which was 3100-3300 l/min was not sufficient and resulted in poor hole cleaning and stability problems. In later sections the pump rate gradually decreased due to the pump pressure limitation of 325 bar, but to mitigate hole cleaning problems the top drive RPM was kept between 150-180. A visible increase in cuttings return was seen when the RPM was increased from 150 to 180 in the 12 ¼” section. Much of the problems encountered were related to directional drilling and surveying. Both rotary build assemblies and steerable motor assemblies were used in the well. The rotary assembly used in the 26” section gave a lower build-up rate than selected, and therefore the inclination in the 17 ½” section was increased from 60 to 62 degree. The steerable motor assembly used in this section did not perform satisfactory as it failed to maintain angle in rotary mode, the reason for this was mainly due to variations in formation hardness and the assembly being too sensitive to WOB changes. After setting the 13 3/8” casing a gyro survey was done and the result was a 14 m difference in TVD and 16 m difference in horizontal reach compared to the MWD measurements. In total there were two MWDs that were changed due to poor performance and one due to failure. The troublesome 17 ½” section was drilled using three different bits. The first bit was changed due to steering problems and two plugged nozzles, the second due to low ROP. It was concluded that the seal on the two last bits was worn out due to high angle in combination with high radial stresses. The bits used in the 8 ½” section was also worn which was considered related to overheating due to plugged nozzles. Torque is a limiting factor in long reach wells and the predicted torque for each section in this well was derived from torque experience from previous wells. For all sections the average maximum was lower that the predicted value and the experience showed that a 0.20 friction factor for both cased and open hole fits the actual measured up and down weights (B. Rasmussen 1991).

The next ERD well to de drilled was the C3 which broke the world record with a 80 degree sail section giving a horizontal reach of 6086 m over a measured depth of 7250 m. The well was drilled and completed in 141 days, where 23 days was lost due to top drive gearbox failure and parting of 6 5/8” drill pipe. Based on the experience from C10 the team some key factors for success was derived. Simulations using friction factors derived from C10 was used to create the well profile that would give the lowest torque throughout the whole well. The simulation showed that the torque in the 12 ¼” section would exceed the drill pipe torque rating and therefore a combination of 6 5/8” and 5 1/2” drill pipe were used. The different combinations used in the sections also improved the annular velocity which also was believed to increase the hole cleaning. To handle the expected torque the top drive had one extra gear installed (A. Njaerheim 1992). For the well success it was deemed crucial that the 13 3/8” casing would case in the weak zone at 1760 m TVD and in addition cover as much of the over-pressured reactive shale formation. Based on this it was decided to use a 24” surface casing and a 18

5/8” liner to reduce the length of the 17 ½” open hole section. The directional surveying was a weak area in C10 and to enhance this it was decided to run gyro survey on wireline for the first three sections, pump gyro survey down in the next and in the 8 ½” only MWD and electronic magnetic multishot (EMM) survey. Some drilling problems were encountered in this well. In the 22” hole section all three cones on the bit fell off requiring the well to be sidetracked. The time consuming incidents occurred in the 17 ½” section requiring two sidetracks and replacing the top drive with the old Kelly due to gearbox failure. The first sidetrack at 1620 m MD was due to the motor casing twist off at a service connection and loss of bit, near bit stabilizer and mud motor rotor. The sidetrack was drilled was drilled to 3141 m before encountering severe problems when pulling out of hole, as the cuttings packed off the BHA and subsequently mud losses occurred. The string pulled out while backreaming and at 1973 m the top drive broke down. In addition at this point it became clear that the 6 5/8” drill pipe had parted and 422 m were left in the well. It was possible to retrieve all the drill pipe, but 220 m were left in the well and three cement plugs was set before sidetracking. In the sidetrack the mud viscosity, pump rate and drill string rotation was increased to mitigate the hole cleaning issues encountered in the initial hole. No major change in the cuttings transport was observed by the pump rate and viscosity increase, but the drill string increase during backreaming from 90 to 180 RPM showed large amount of cutting and caving over the shaker. It was estimated based on the cuttings return that the 17 ½” hole was enlarged to between 25” and 28”. The 12 ¼” section was drilled to TD using the hole cleaning experience from previous section and excellent hole cleaning was observed while rotating the drill string with 180 RPM. This section had problems with directional surveying which was the reason for pulling the string to surface two times. The first pull out was due to a gyro survey run on wireline failure, where the rubber pump down head was left inside the drill string. The second time was due to poor MWD signals related to a wash-out. After reaching TD a tandem EMM survey was pumped down, but only one of the instruments produced a good survey. The reason for only one good survey was that excessive vibrations caused to connection to loosen. Several attempts to pump down gyro surveys were done before cementing the 9 5/8” casing, but they failed to reach TD. To solve this problem the gyro survey was tied together with a cement wiper plug and was successfully pumped to TD. An increase in pump pressure broke the rope and the gyro survey was logged out the hole. The 8 ½” section was drilled without any incidents. To achieve good hole cleaning the drill string was rotated with 50 to 120 RPM, and again it was shown that an increase in RPM resulted in better hole cleaning. A RFT log was run and showed that it was possible to reduce the mud weight to achieve higher pump rate while cementing the 7” liner. The liner was placed with rotation and full mud return (A. Njaerheim 1992).

After successfully drilling the two first ERD wells, a project was launched in 1992 to find the theoretical optimal well profile. Field data from the previous wells was used to establish friction factors and a realistic torque and drag simulation. The simulations showed that the optimum well profile would be a modified catenary profile with a low build-up rate, which would minimize the contact between the drill string and the wellbore wall. One additional measure done in the planning phase was to limit the directional steering interval to 4-7 m, instead of the whole single pipe which was common practice. The reason for this action was to reduce the torque which is induced by dog-leg creation from the steering, as it was shown in earlier wells that dog-legs creating in the start of the well had great impact on the later overall torque measure. The first well to use the mentioned design on Statfjord was C24 and later the world record breaking C2. Experience from C24 was used to improve the design and drilling procedure for C2 achieved a horizontal reach of 7290 m over 8761 m MD. In C2 the casing design for the 12 ¼” section was changed to a 9 5/8” liner instead of a casing to provide sufficient pump rate for good hole cleaning in the 8 ½” section (T.E. Alfsen 1995). Available pump pressure to provide sufficient pump rate was a challenge for both 17 ½” and 12 ¼” section, therefore as much as possible 6 5/8” drill pipe was used both in the 17 ½” and 12 ¼” section to minimize the frictional pressure loss inside the drill string and to increase the annular flow. The long 12 ¼” was drilled without any major problems and the ester based mud system provided good hole cleaning and a lower friction factor that previously observed with OBM. Good hole cleaning in this section was obtained by the combination of ester based mud system and high drill string rotation. This resulted in actual torque values between the predicted and the optimum. The MWD tool was replaced four times in this section to reduce the uncertainty ellipse related to the wellbore. This was necessary to prevent the shut-in of the nearby wells C10 and C3. EMM surveys were unsuccessfully performed in this section, the reason was the difficulty of pumping this survey down the large 6 5/8” drill pipe. Gyro surveys was pumped down after running the 9 5/8” liner, even though the rope broke 1000 m MD prematurely a close comparison between the gyro and MWD was obtained to this point. A total loss of 105 $m^3$ was observed while displacing the cement. The probable reason for this was formation fracture due to barite sagging caused by insufficient circulation before cementation Only rounds of circulation was performed. A leak in the casing shoe was also observed after the cementation, this was considered related to wear due to going through 7409 m of tubular. The drilling of the 8 ½” section was done with only minor directional survey problems in the chalk stingers. Very good hole cleaning was achieved in the section which resulted in actual torque values bellow the optimum value. The 7” liner was run to TD at 8489 m MD with minor problems. The centralizer used gave some additional drag when entering the 9 5/8” liner top and additional weights was used before entering the open hole. Rotation of the liner was unsuccessfully attempted in the open hole due to some hole condition problems. Therefore, the liner was circulated down and placed after 18 hours. Rotation was the possible and maintained during mud weight reduction and cementation (T.E. Alfsen 1995).

## 2.3 Learning From Wytch Farm and Statfjord

The experience gained from the ERD projects on WF and Statfjord was beneficial for the whole industry as they extended the drilling envelope and showed that long reach wells were possible from both offshore and onshore installations. The close cooperation with service providers gave a continuously improvement and evolution of equipment that made longer wells possible. A game changing event for ERD occurred with the introduction of RSS, which eliminated the non-rotating time while steering, that was necessary during earlier systems. The previously stationary steering systems induced additional torque by the additional dog-leg creation. To overcome this problem the Statfjord team used experience from previous wells to reduce the steering from whole pipe lengths to only 4-7 meters, which successfully minimized the problem with the available technology. Hydraulics is a major problem in long wells due to the frictional pressure loss inside the drill string which limits the available pump pressure and hole cleaning. Hole cleaning problems on Statfjord was minimized through the implementation of 6 5/8” drill pipe, high drill string rotation and development of a mud system with good transport capability. On WF fibrous LCM had a positive effect on both torque reduction and the hole cleaning. Mud losses was a large problem in the early WF wells and the creation of realistic fracture and pore pressure estimates was considered to be one of the main contributions for the WF success. Both fields had great success with using experience from previous wells to decide upon a friction factor that was used to design models for torque and drag predictions. The simulations showed that a modified catenary well profile would obtain the lowest torque value and the experience from C2 on Statfjord showed that the actual torque was lower than the predicted and at times even lower than the optimum value. This was also due to the very good hole cleaning achieved in this well. The large torque values observed during ERD wells showed the need for increasing the drill pipe limits and top drive capacity.

# 3 Limitations of Conventional ERD Wells

ERD wells are known to include specific planning and optimization to overcome expected problems associated with long wells. This includes optimization of equipment, rig and procedures to mitigate anticipated challenges in these complex wells. A roughly estimate of a wells complexity can be derived from the ERD ratio, as seen in Figure 1. This figure contains the mentioned wells from WF, Statfjord, Al-Shaheen and Sakhalin project, more information about these wells are provided in Appendix A. The method states that the well complexity increase with increasing ERD ratio. As seen from figure 1, the Al-Shaheen well have a much larger ERD ratio, than the wells drilled at Sakhalin. The wells have approximately the same length, but there is difference in the reservoir depth. This showed the roughness of the model, it is therefore important to remember that the ratio is very depth dependent and give poor relation between wells at different depths. As of October 2013, 16 of the 20 longest wells in the world are drilled at the Sakhalin project. This achievement became possible due to the continuously improvement of equipment, design and procedures made during the process. Z-42, which have the longest horizontal reach in the world, is drilled on Chayvo field in the Sakhalin project. Customized equipment, procedure and design provided the longest wells, and thus serving as a benchmark for the ERD wells (V.P.Gupta 2014). Therefore, elaboration of experience from Odoptu, Chayvo field and Z-42 are given in the following subchapter.

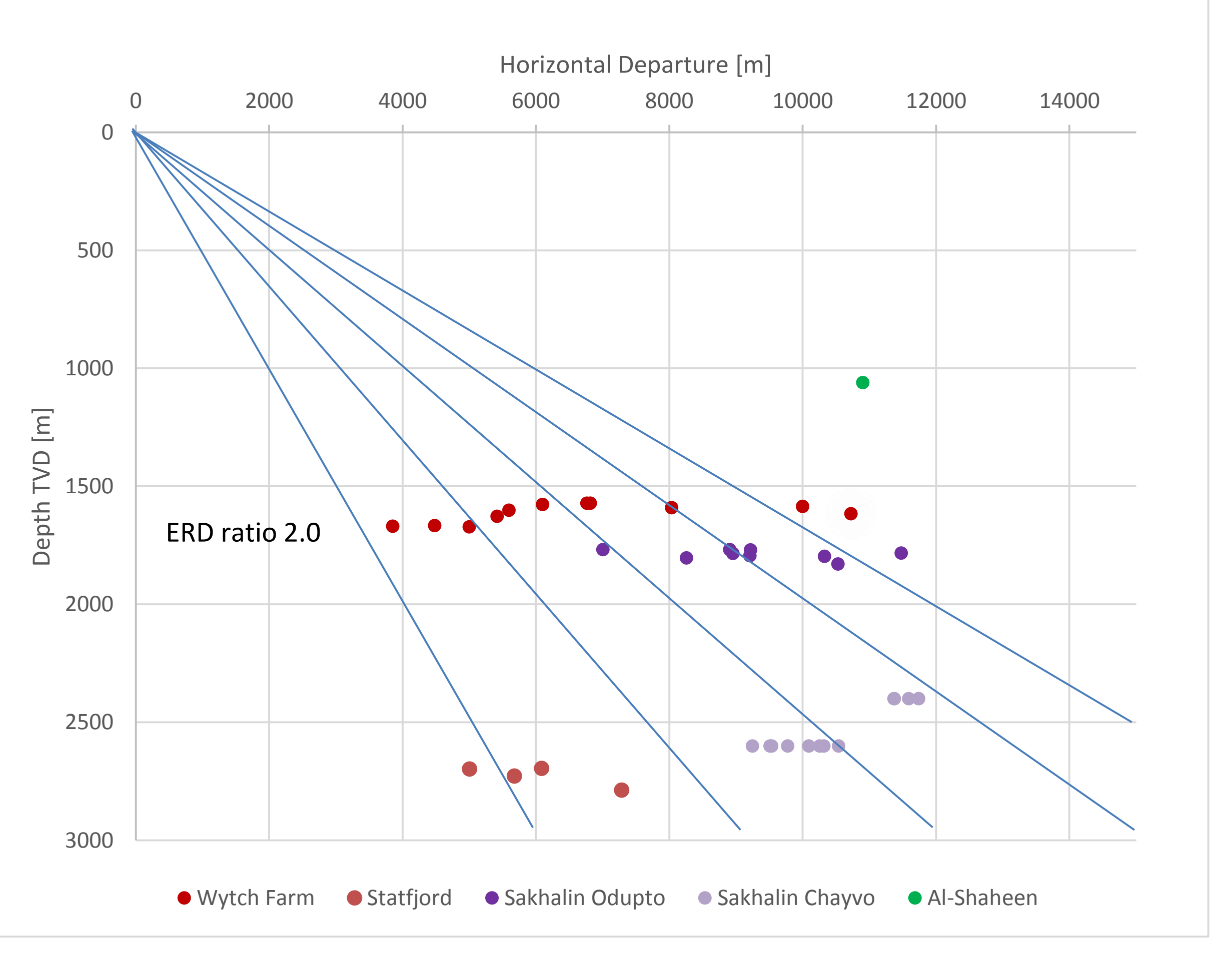



**Figure 1. ERD ratio**

All the fields in Figure 1 have contributed largely to the evolution of ERD and have pushed the limit to a current maximum. These fields pushed the limit by challenging the industry to provide better equipment, fluids and procedures to deliver world record well from the start. Table 1 shows some selected wells of interest from these fields to highlight the rapid evolution within technology, equipment and experience with ERD wells in the early 1990s. The first ERD well on WF had a reach of 3,856 m and nine years later, the 10 km milestone were broken. From 1997-2013, the additional increase in horizontal reach was 1,700 m. This shows how fast the evolution in the start was, and how early the industry approached the limitation of conventional ERD wells. These limits were pushed in projects due to the identification of large cost and environmental benefits through ERD applications.

| Year | Well | Field | MD [m] | HD [m] | TVD [m] | HD/TVD |
|---|---|---|---|---|---|---|
| 1988 | F18 | Wytch Farm | 4450 | 3856 | 1669 | 2.31 |
| 1990 | C3 | Statfjord | 7250 | 6086 | 2696 | 2.26 |
| 1992 | C2 | Statfjord | 8761 | 7290 | 2788 | 2.61 |
| 1995 | M5 | Wytch Farm | 8715 | 8035 | 1591 | 5.05 |
| 1997 | M11 | Wytch Farm | 10658 | 10000 | 1585 | 6.31 |
| 2008 | BD-04A | Al-Shaheen | 12290 | 10903 | 1061 | 10.28 |
| 2011 | OP-11 | Odoptu | 12345 | 11479 | 1784 | 6.43 |
| 2013 | Z-42 | Chayvo | 12700 | 11739 | 2400 | 4.89 |

**Table 1. ERD Evolution**

When developing a field the operator conducts a feasibility study, to determine if it is possible to perform the wanted operation or to undertake a certain project. This is the case for all ERD projects, where the study analyze wells for certain limiting conditions. These limiting conditions (B. Foster 2007) are:

- Maximum expected torque load is within the top drive and drill string components rating
- Maximum expected tensile load is within rig's hoisting capability and drill string tensile rating
- All tubular shall slide or rotate into the well without excessive negative weight or buckling
- Ability to maintain adequate flow rate and rotation for hole cleaning without exceeding fracture gradient.
- Ability to maintain adequate mud weight and rheology for hole cleaning and wellbore stability without exceeding fracture gradient.

If the well is deemed feasible, it means that with proper planning the work can move towards of drilling. This method can be used to really asses how far it is possible to drill with the available equipment and are useful for identifying possible limiters in the project. This relation can then be used for identifying current boundary conditions for successful operations. Result from the study may highlight the need for MPD or UBD to make it feasible, due to shortcomings in conventional drilling.

## 3.1 Sakhalin Project

The Sakhalin project consist of the three fields Chayvo, Odoptu and Arkutun Dagi, developed and operated by Exxon Neftegas Limited. The Chayvo field was first developed, before the Yastreb rig was moved and upgraded to the Odoptu field that consists of nine ERD wells, where several are among the longest ERD wells in the World, including the OP-11. After drilling the Odoptu field, the rig were moved back to the Chayvo field for an infill program, to access northern part of the reservoir. The fields are located off the coast of Sakhalin Island, Russia, in a sub-arctic climate with temperatures dropping below minus 40 Celsius. Figure 2 shows the Yastreb rig on the Chayvo drill site. In addition, the field is in a tectonic active area, as it is located on the northeastern edge of the Eurasian tectonic plate. The most recent earthquake recorded was in 1995, measured to 7.6 on the Richter scale.

**Figure 2. Chayvo drill site on the Sakhalin Project (M. Grini 2009)**

To overcome these challenges the operator early in the development designed and built the world largest fit-for-purpose land drilling rig, Yastreb. Throughout the development the rig was upgraded to meet the requirements to drill longer wells. The wells on the Odoptu field are drilled to a shallower depth than the previously drilled Chayvo field. Higher torque rated drill pipe were acquired to meet the increasing torque and drag challenge associated with drilling these shallow wells. The rig was further upgraded after drilling the Odoptu wells and the rig specifications during Chayvo field phase two are listed in Table 2 (R.W.James 2012, V.P.Gupta 2014).

| Item | Specification |
|---|---|
| Derrick | 1,500,000 lb, fully winterized and earthquake resistant |
| Top Drive | TDX-1250 with 2x1340 HP engines 70,000 ft-lbs at 170-180 RPM |
| Mud Pumps | 4 National model 12-P-160 mud pumps, 7500 psi Standpipe |
| Shakers | 8 Derrick Flowline |
| Drill Pipe | 6-5/8" XT-69, 80,000 ft-lbf makeup torque |
| Drill Pipe | 5-7/8" Enhanced 2nd Generation DSC with 71,000 ft-lbf makeup torque |
| Mud System | 2,000 bbl Active, 2,000 bbl Reserve, 2x5,000 bbl pits, heated and enclosed |
| Generators | 6 Caterpillar 3516B |

**Table 2. Yastreb Rig Specification (R.W.James 2012, V.P.Gupta 2014)**

To accomplish these record breaking wells the operator planned to use the first wells to gain knowledge and experience from drilling step-wise longer and longer wells. All wells drilled on Odoptu field was analyzed and lessoned learned noted. Improvements were then implemented in the planning and execution of the next well. Much effort was put into increasing the operating time of BHA and MWD's, since a round-trip to change the equipment could take up to six days in these long wells. One tool used in this process is mechanical specific energy (MSE), which is a measure of how efficiently the energy in the drill string is used to drill the actual hole. This is a real-time measurement that provides the driller the necessary information to adjust parameters for maximizing ROP and minimizing bit/tool damage (M.W. Walker 2009). On a general level the toque and drag management will be the largest challenge when drilling ERD wells, like on the Odoptu field. Here the high torque and drag associated with drilling and running tubular were overcome by adding lubricants. The torque and pick-up load was generally 10% lower when using lubricants in the operation. In addition, well profile and drilling procedure optimization helped on reducing the torque and drag on a general level. Throughout the project, this constant focus on improvement have resulted in an overall drilling performance increase, and a decline in NPT from 21% for the first four wells to 3% for the last five wells.

After drilling the Odoptu field, the rig were moved back to the Chayvo field for an infill program, to access northern part of the reservoir. These wells had to be placed very accurately as the target was a thin oil column. The well placement was one of the major challenges for these wells and a new technique was used to reduce the placement uncertainty. This technique used the pressure information versus TVD from a near vertical offset well to correlate the TVD in the ERD wells using a LWD tool with high quality formation pressure data acquisition, the real-time data was used to decide which actions that had to be done to place the well correctly. This technique reduced the uncertainty to an acceptable level of ± 1.7 m (V.P.Gupta 2013). Other limiters that were identified after the Odoptu drilling, was the 5-7/8" drill pipe, where the connection torque limit were 56,600 ft-lbf. A 5-7/8" non-shouldered drill pipe with torque limit of 100,000 ft-lbf had also been tried, but these pipes reduced the operational efficiency in addition to require more rig time for make-up and break-out. Therefore new drill pipe with a second generation double-shoulder connection and torque limit of 71,000 ft-lbf were acquired (S.R.Sanford 2014). The solid control during the drilling of the 17-1/2" section were also identified as a limiter, thus the rig was upgraded from six to eight shale shakers to reduce the drilling time. All improvements and upgrades are done based on the experience from the Odoptu drilling and the well design are similar to the Odoptu wells. This called for a deep-set 13-5/8" casing and a 9-5/8" liner which is floated down to TD. As on the Odoptu field the 13-5/8" casing setting depth is based on the desire to keep the whole 9-5/8" liner inside the casing before switching over to the mud filled running string. As a contingency, a casing rotation tool was implemented in the crossover between liner and running tool. Other factors that have been improved throughout the whole Sakhalin project are the drill bit and BHA lifetime. The operator have optimized the drill bit and BHA design to minimize vibrations and stick-slip to maximize the tools life and to reduce the friction increasing patterns that vibrations induce to the well path. Filter subs are also included in the BHA to reduce the potential for equipment failure due to debris in the mud. The tools lifetime will also affect the quality of the wellbore as a roundtrip to change out a part can take 4-5 days in these long wells, and thus degrading interactions between formation and wellbore fluids may occur. These continuous improvements and advancements are possible due to the consistently gathering of lessoned learned and data from every operation throughout the whole project, and this have been one of the main contributors to the project success (V.P.Gupta 2014).

### 3.1.1 The world's Longest Horizontal Reach

The project used a batch operation for the 30" and 18-5/8" casing to minimize the mud changes and achieve higher efficiency through repetitive operations. Hence, the first considered hole drilled in the World's longest ERD well Z-42 is the 17-1/2 section, which is drill out of the 18-5/8" casing that were set with a 36° angle at TD.

| Drilling Parameter | 17-1/2" section | 12-1/4" section | 8-1/2" section |
|---|---|---|---|
| Section length MD [m] | 3881 | 4471 | 3522 |
| Depth MD [m] | 4707 | 9178 | 12700 |
| Pump rate [GPM] | 1300-1350 | 1050-1150 | 450-530 |
| Inclination at TD | 82 | 90 | 90 |
| Drill pipe | 6-5/8" | 6-5/8" | 6-5/8" and 5-7/8" |
| Drill Bit | PDC | PDC | PDC |
| Mud & Mud Weight [ppg] | NAF 12.2 | NAF 12.2 | NAF 12.2 |
| FIT [ppg] | 14.5 | 16 | 18 |
| ROP [m/hr] | 59-107 | 20-68 | 16-35 |
| RPM | 170-200 | 170-180 | 115-160 |
| WOB [klb] | 50 | 35-40 | 30-42 |
| Max Surface torque [kft-lb] | 42 | 71 | 70 |
| Number of BHA used | 1 | 2 | 2 |
| Limiting element | WOB/Buckling | Top Drive Torque capacity | Drill pipe torque capacity |

**Table 3. Drilling parameters in Z-42 (V.P.Gupta 2014)**

This record well were drilled and completed in just over 70 days and during the operation, only 13 hours were NPT. As seen in Table 3 the limiting factor in the 17-1/2" section was the maximum allowable WOB to avoid wear on the drill pipe due to rotation of buckled pipe. However, for the two last section the torque management were the limiting factor, with respectively the capacity of the top drive and the drill pipe connections. Some of the initiatives taken to reduce the potential for BHA failure were installing the finest mesh screens on the shale shakers to reduce low gravity solids in the mud, and the installing of a filtration sub in the BHA. In addition, analysis to reduce the vibration tendencies in the BHA were performed. As seen from Table 3, the drill string were pulled to surface in the last two section due to BHA failure. In the 12-1/4" section the BHA had to be retrieved due to mud pulse tool failure, and in the 8-1/2" section the BHA were retrieved from 10,102 m depth due to failure of the rotary steerable tool. Liquid lubricants were added to the mud system in the two last sections to reduce the torque and drag, for the 12-1/4" section it was done during backreaming to prepare the well for running the floated liner. In the 8-1/2" section the liquid lubricants were added to manage the high surface torque which approached the maximum level, here the lubricant concentration were increased steadily up to 4 %. The RPM were reduced two times to aid in keeping the surface torque within the maximum limit. The operator managed the surface torque at stable value between 60-70 kft-lbs for the last 2,000 m after adding lubricants and adjusting the RPM (V.P.Gupta 2014). When running the 9-5/8” liner the operator accounted for the surge effects, due to the hook load reductions observed in the Odoptu wells. Observations here showed that the hook load reduction of 40 to 50 Kip by only starting up the pumps to drilling rate. This introduces compressive forces to the drill string which may affect the drilling performance due to poor weight transfer to the bit, higher surface torque and drill pipe buckling. It was also observed, that when approaching the buckling limit only minor changes to the mudflow are necessary to improve weight transfer and ROP (M. W. Walker 2012).

## 3.2 Limiting Factors

When designing a well it is important to investigate several scenarios to uncover which factor that will be limiters for the design. The investigation is performed for all designs, but for long reach wells, this becomes more complicated as the operating window are narrower. Hole cleaning, torque and drag, wellbore stability and buckling are all factors that are connected together and where a change in one parameter can make an impact all. Hole cleaning is obtained by using a sufficient flow rate to transport the cuttings out of the well and pipe rotation to aid in cutting bed prevention and transportation. This is a challenge for long wells that have a large frictional pressure loss throughout the well, which results in a high ECD that potentially can fracture the formation. There are different kinds of ERD wells also, where some are shallow with large horizontal displacement and other are deep with less horizontal displacement. The difference in TVD introduce different challenges during the design and drilling phase. Deep TVD wells are limited by the hoisting capacity of the rig and the yield strength of the drill string, while torque is the limiting factor for shallow TVD wells. This behavior is showed in the example presented in 3.2.1. During drilling the string is subjected to contact forces in the bend and in the straight section as shown in Figure 3. This contact force is the main contributor for frictional torque and for drag. The magnitude of the contact load are determined by hole size, dog-leg severity, inclination, drill pipe specifications, drill string weight and tension/compression loads. Therefore, profile optimization, mud configuration and directional control are vital elements to keep the contact load on a manageable level. Directional drilling can create much tortuosity and thus increase the contact area between wellbore and string. This was observed and recognized as a large problem for both Wytch Farm and Statfjord, where procedures to minimize non-rotation steering were implemented to reduce the problem. It was also a problem in OP-11 while drilling the 17-1/2” section, when the steering assembly had a building tendency due to excessive wear on the stabilizers.

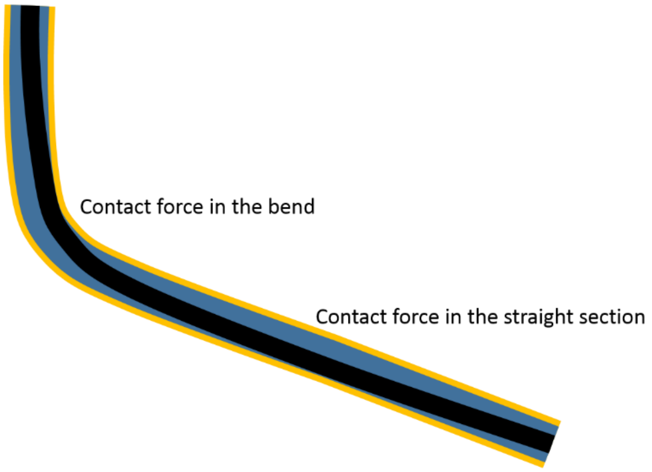



Figure 3. Wellbore contact

Another limiting factor for ERD that were identified in the Sakhalin project was BHA life. A component failure may result in pulling the string and leaving the borehole open for several days and in worst case, a lost well. Interaction between the drilling mud and formations may lead to wellbore instability and introduce several drilling problems when re-entering the well again. Drilling a section with only one BHA will save several drilling days and reduce the probability of wellbore instability. Bit design and vibration analysis are key factors in enhancing the operational life of BHA's.

### 3.2.1 Torque and Drag

Simulations of torque and drag are implemented early in the design phase to ensure the project feasibility with respect to drill string components and field data. The result from torque and upward drag simulations are used to ensure that the rig is capable of managing the drill string weight and rotation, in addition to ensure that the drill string components are able to withstand the tension. The downward drag gives information about the limits of running tubular. The downward drag introduce additional challenges to the simulation as the compressive forces increase with drag and this can initiate drill string buckling which further increases the drag and drill string stresses. As long as the compression is below the critical buckling load, the string can withstand the load and maintain its shape. Sinusoidal buckling is the first stage of buckling and is initiated when the critical buckling load is reached, when this occur the drill string will obtain a snaky shape which increase the wellbore contact area and drag is further increased together with compression. If the load further increase the string will coil up inside the wellbore and helical buckle, the string is then in a lock-up situation where it is not possible to push the drill string further down the well. The severity of sinusoidal buckling is measured by the angle between the wellbore low side and the drill string, if the angle remains below 40 degree the buckling will not cause significant increase in drag and is considered acceptable. In general, buckling cannot be avoided in ERD well and must therefore be accounted for in the torque and drag simulations (M.L.Payne 1997).

When drilling a well towards the target the path often involves build-up bends, drop-off bends, sail sections and side-bends. All these path changes contributes to the overall torque and drag that occur in a well and therefore the selection and optimizing of the wellbore profile is crucial in successfully reaching target. The following equations are based on the assumption of soft string model, which implies that bending stiffness can be neglected due to the small pipe bending (B.S. Aadnøy 2010).

Figure 4 shows the different forces that acts on the drill pipe when it is located in the sail section of the well, and the formula for these forces are given in equation 3.1, where the plus and minus sign are respectively used when calculating hoisting and lowering.

$$F_2 = F_1 + \beta w \Delta s(\cos\alpha \pm \mu \sin\alpha) \tag{3.1}$$

From this equation one observe that the normal weight is the only component that provide friction and therefore this section is dominated by the weight. This equation is also used for the vertical section, as it will provide the result of the pipe weight for this section and the forces from lower sections.

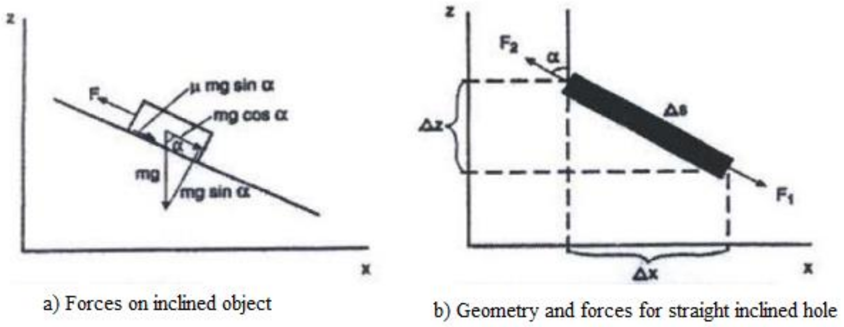



**Figure 4. Principle of forces acting on an object on a inclined plane (B.S. Aadnøy 2006).**

Torque is the rotating friction and for this section, the principles for drag applies her. The normal weight component is multiplied with the friction factor and pipe the tool joint radius.

$$T_2 = T_1 + \mu\beta w \Delta s r \sin\alpha \tag{3.2}$$

The formula shows that the pipe tool joint radius is an important factor and selection of tool joints with a smaller outer diameter can reduce the torque. The effect of selecting a smaller outer diameter tool joint is shown in the following example.

The drag for curved wellbore sections are dominated by the tension, as the normal contact force between the string and wellbore is strongly dependent on the axial loading. Equation 3.3 is a general equation for drag in build-up, drop-off or side-bends, where plus and minus sign is for respectively hoisting and lowering. Equation 3.4 is a general equation for the torque in these sections.

$$F_2 = F_1 e^{\pm\mu|\theta_2-\theta_1|} + \beta w \Delta s [\frac{\sin\alpha_2 - \sin\alpha_1}{\alpha_2-\alpha_1}] \tag{3.3}$$

$$T_2 = T_1 + \mu r F_1 |\theta_2 - \theta_1| \tag{3.4}$$

As mentioned in the earlier subchapter there is a difference in limiting factor for wells that are heading for a deep or shallow target. Two wells are created in the following example to show how the torque and drag forces are affected by the difference in depth. Figure 5 shows the well profiles for two wells and the outcome from torque and drag calculations without pipe rotation are shown in Table 4. Further calculations are provided in Appendix C and conversion factors are shown in Appendix B. The wells have approximately the same measured depth but are differentiated by their kick-off depth and subsequently sail section length. The example contains three different cases to illustrate the different limitations regarding depth of wells and drill pipe connection size. The drill string for the example is 5” g-105 drill pipe and a 100 m long simplified BHA consisting of 8”x3” drill collars (VAM-Drilling 2014).

Case 1 and 2 shows how the rig hoisting capability and pipe yield strength is the limiting factor for deep wells and that torque is the limiting factor for shallow wells. While case 1 and 3 shows that the torque can be reduced with approximately 17 percent, when changing the tool joint connection from the 7” outer diameter 5-1/2 FH connection to a 6” outer diameter Vam Express VX4. The example shows how important the tool joint outer radius is to reduce and manage the torque in wells, it also shows the importance of proper well profile planning and selection of drill string components before drilling an ERD well, which stretch the limits of conventional equipment.

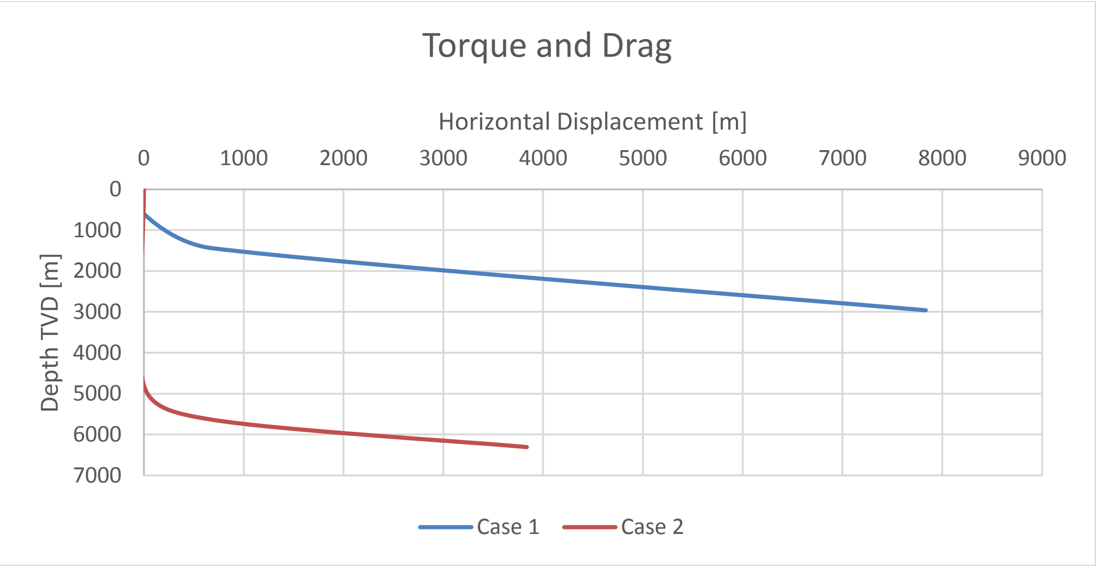



**Figure 5. Well profile of deep and shallow kick-off point wells**

| Case | Static Weight [KN] | Hoisting [KN] | Lowering [KN] | Torque [KNm] |
|---|---|---|---|---|
| Case 1 | 835 | 1522 | 411 | 48 |
| Case 2 | 1745 | 2029 | 1542 | 23 |
| Case 3 | 804 | 1467 | 396 | 40 |

**Table 4. Torque and drag comparison of shallow and deep kick-off point wells**

### 3.2.1.1 Real-time Measurement of Torque and Drag

One of the challenges with excessive drag in the well is weight transfer from the drill string to the drill bit. The result of the drag effect is that the downhole WOB is different from the observed WOB on surface. An intelligent Drilling Advisory system (IDAs) have therefore been developed to deliver a real-time estimation of friction factor and the effective downhole WOB. The system receives real-time data such as surface hook-load, pump pressure, drill string RPM, surface WOB and survey measurements and use a 3-dimensional wellbore friction analysis to estimate friction factor and effective downhole WOB in the different operation modes like lowering, hoisting and drilling. The system can aid the drilling engineers in making better decisions and optimize the drilling operation. The optimization can involve adjusting the surface WOB to obtain a better ROP. The system was utilized during drilling of some horizontal wells in Western Canada. The result showed that the effective downhole WOB was in the range of 60-70% of the observed surface WOB. The result from the IDAs was in agreement with the recorded WOB from a downhole measuring tool. Some of the overall benefits with such a real-time system is that the drilling efficiency can be optimized by adjusting the WOB and detection of tight spots or poor hole cleaning (M. Tahmeen 2014).

### 3.2.2 Hydraulics

Mud is used in drilling operations to maintain a sufficient pressure inside the wellbore, to cool and clean the bit and to transport the cuttings to surface. The mud is pumped down the drill string, through the bit and upward in annulus. There will be a pressure loss from the initial pump pressure due to the frictional pressure loss inside the string, through the bit nozzles and up annulus. The mud flows in two different patterns, either laminar flow or turbulent flow, depending on mud characteristics and flow rate. Laminar flow is when the mud flows along a defined path, while in the turbulent flow the flow path is chaotic. In a horizontal pipe the laminar flow have a parabolic shape where the flow velocity is largest at the center of pipe and zero along the pipe wall. A turbulent flow in the same pipe would have a flat vertical flow shape with a larger flow velocity closer to the wall. This gives the flow a shorter distance to decrease to zero and therefore the shear becomes stronger, which means that the friction increase (R.W. Time 2013). In drilling operations, the flow inside the drill string is normally turbulent, since the small cross-sectional area results in a large flow velocity. The drill bit have a specific number of nozzles with a small cross-sectional area and therefore the flow velocity increases significantly over the bit. In annulus, there is low available flow area around the BHA and can results in turbulent or laminar flow in this section, while the available flow area increase above the BHA and the flow is in laminar flow. Thus, the total pressure loss in the operation is a combination of laminar and turbulent flow. The pressure drop in the operation can be divided into two groups, the pressure drop over the bit and the pressure drop for the rest of the system, called the parasitic pressure drop.

Equation 3.5 give the needed pump pressure when we divide the pressure drop into the useful pressure drop over the bit and the parasitic pressure drop (B.S. Aadnøy 2010).

$$P_1 = P_2 + P_3 \tag{3.5}$$

- $P_1$ = pump pressure
- $P_2$ = pressure drop across bit
- $P_3$ = parasitic pressure loss

The turbulent flow inside the drill string dominates the parasitic pressure drop, while the laminar parts of the system contributes to 10-20 % of the total pressure drop. The parasitic pressure drop equation 3.6 is therefore dominated by the turbulent flow.

$$P_3 = Cq^m \tag{3.6}$$

- C = proportionality constant
- m = flow rate exponent

The pressure drop across the bit is given by the continuity equation and by applying the principle of conservation of energy and assuming an incompressible and frictionless system the equation for pressure loss can be derived. Two simplifications are done for this pressure loss. The drill string velocity can be neglected, since the flow velocity inside the drill string is very low compared to the nozzle velocity. Experimental measurements have shown that the basic equation over-estimates the flow rate and therefore a discharge coefficient is included. Equation 3.6 express the simplified pressure drop across the bit.

$$P_2 = \frac{\rho q^2}{2A^2 0.95^2} \tag{3.7}$$

- q = flow rate
- A = area
- 0.95 = discharge coefficient

The pressure drop across the bit is a surface pressure, applied inside the drill string and will increase the axial tension in the string. This additional force should be included in uniaxial failure considerations for the drill pipe. Using the well and drill string information for case 2 from the previous example one can see how the static hook load increase due to the applied pressure. A PDC bit with seven identical nozzles and a flow rate of 450 Gpm are used in this example. The additional forces that the pressure drop contributes to are added to the buoyant weight of the drill string. Table 5 contains information and calculations of components in these calculations. The change in hook load is shown in Figure 6. The hook load were increased, but it were still below the drill pipe tensile limit.

| | | |
|---|---|---|
| Nozzle area | $7 * \frac{\pi * \left(\frac{9}{32} * 0,0254\right)^2}{4}$ | 0.0002806 m$^2$ |
| Flow rate | $\frac{450 * 0.06309}{1000}$ | 0.02839 m$^3$/s |
| Density | 1.46*1000 | 1460 kg/m$^3$ |
| $P_2$ | $\left(\frac{1460 * 0.02839^2}{2 * 0.0002806^2 * 0.95^2}\right) * 10^{-5}$ | 82.8 bar |
| Drill collar | 8"x3" | Inner radius of 0.0381 m |
| Drill pipe | 5" and tensile limit of 2457 KN | Inner radius of 0.0543 m |
| DC forces | $(82.8 * 10^5 * \pi * 0.0381^2)/1000$ | 38 KN |
| DP forces | $(82.8 * 10^5 * \pi * 0.0543^2)/1000$ | 76 KN |
| Hook load Case 2a | | 1745 KN |
| Hook load Case 2b | $1745 + 38 + 76$ | 1859 KN |

Table 5. Pipe and hydraulic system data

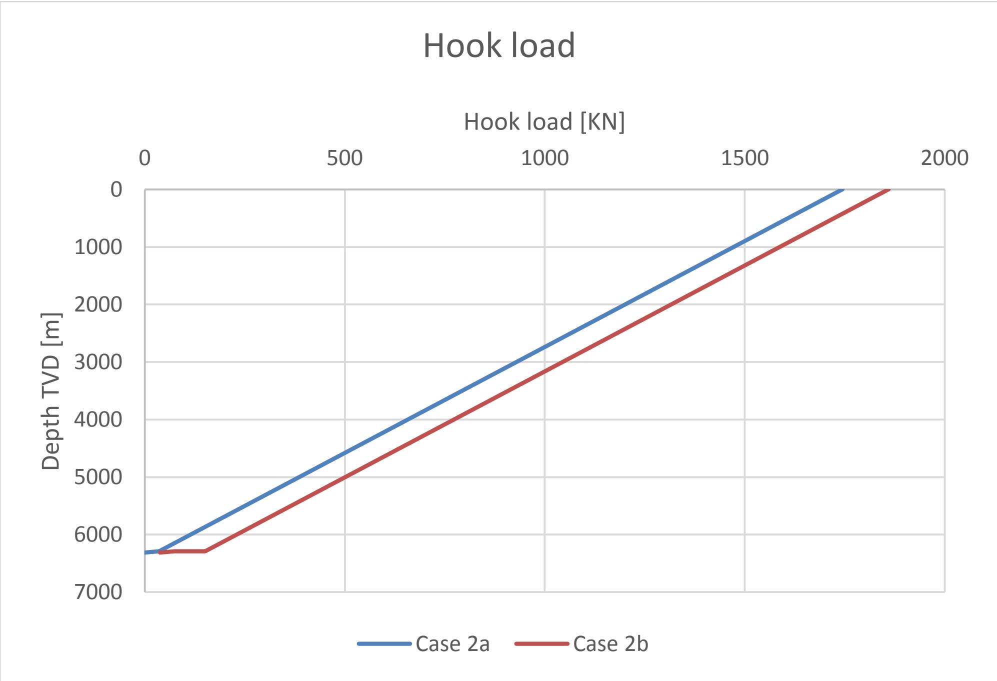



Figure 6. Hook load

### 3.2.3 Hole Cleaning

Hole cleaning is a very important factor when drilling a well. Adequate hole cleaning is achieved by maintaining the flow rate above the minimum flow rate for hole cleaning, this is also called the critical flow rate (CFR). The hole cleaning will be inadequate if the selected flow rate is below this limit. Inadequate hole cleaning results in cuttings settling in the well and on the low side in horizontal wells, these cutting beds can result in large drilling problems. It is a known fact that severe drilling problems like large torque and drag, hole pack-off and stuck pipe can be the result of poor hole cleaning. These problems require remedial action that increase the already high drilling cost. It is therefore important to know the CFR from the start of well planning. The flow rate and mud used in the well should have the correct properties to transport the cutting out of the well, this includes a sufficient flow velocity and viscosity. If these properties are inadequate, the cuttings will sink due to gravity. A model based on field and laboratory measurements have been used to derive some simple charts that can be used to determine hole cleaning requirements (Y. Luo 1994). The well in previous example is used to determine:

- What the maximum safe ROP is, when the mud pumps deliver 450 Gpm.
- What do the flow rate need to be if the hole is washed out to 10 in.

The mud used in this example have a plastic viscosity of 25 cP and a yield point of 18 lbf/100ft$^2$.

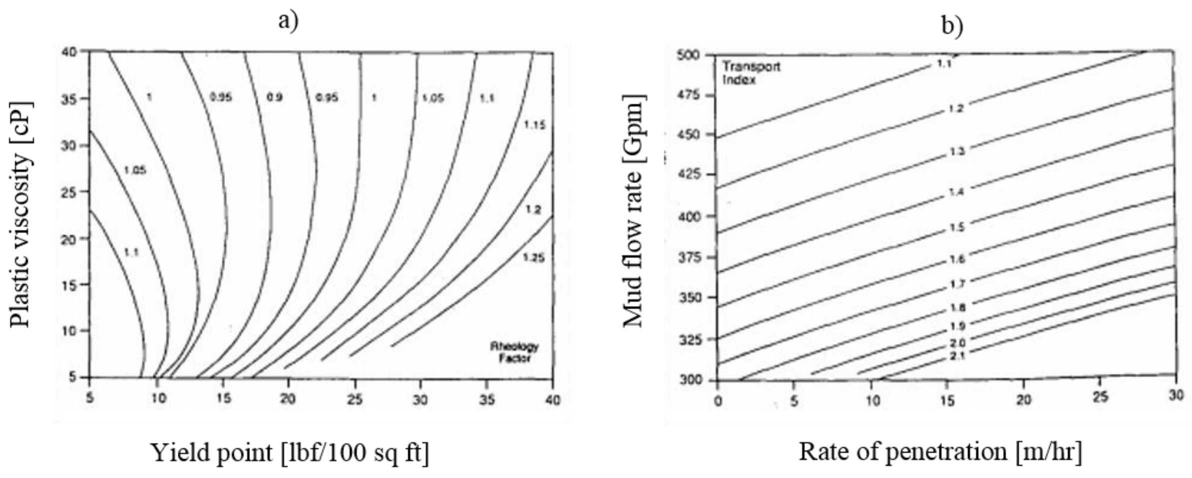



**Figure 7. Rheology (a) and hole cleaning (b) charts for 8-1/2" section (Y. Luo 1994)**

| Hole angle (deg) | 25 | 30 | 35 | 40 | 45 | 50 | 55 | 60 | 65 | 70-80 | 80-90 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Angle factors, AF | 1.51 | 1.39 | 1.31 | 1.24 | 1.18 | 1.14 | 1.10 | 1.07 | 1.05 | 1.02 | 1.0 |

**Table 6. Angle factors for deviated holes, AF (Y. Luo 1994)**

The rheology factor is determined to be 0.90 from the chart in Figure 7a. From Table 6 the angle factor is determined to be 1.02, since the well is inclined with 78 degree. Equation 3.8 use these two factors to calculate the transport index (TI), which is a direct indication of the hole cleaning. A high TI indicates good hole cleaning while a low index indicate poor hole cleaning.

$$TI = RF * AF * MW = 0.90 * 1.02 * 1.46 = 1.34 \tag{3.8}$$

Figure 7b use the mudflow rate and the transport index to decide the maximum ROP possible while achieving good hole cleaning. Reading of the chart gives a maximum ROP of 16 m/hr.

| Washout size [in] | Correction factor, α |
|---|---|
| 9 | 1.12 |
| 10 | 1.38 |
| 11 | 1.65 |
| 12 | 1.94 |
| 13 | 2.24 |
| 14 | 2.55 |

**Table 7. Flow rate correction factors for washout holes (Y. Luo 1994).**

During a drilling operation there is a chance of hole enlargement due to washout. The flow rate needs to be increased for proper cutting transport through the washout section. For this example it is assumed that there is a possible washout section of 10 inches. Equation 3.9 gives the new flow rate that is needed for proper hole cleaning. Enlargement of the hole to 10 inches will required a flow rate of 621 Gpm, this is an increase of 38 percent.

$$CFR_{washout} = \alpha * CFR_{gauge} = 1.38 * 450\ Gpm = 621\ Gpm \tag{3.9}$$

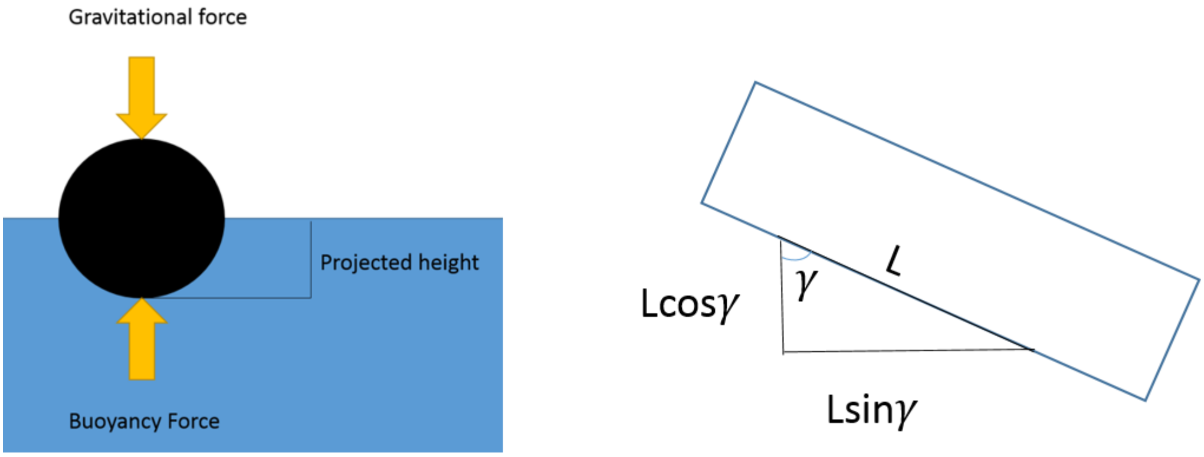
This chance of washout should be included in the design and contingency plans should be made to account for the increase in flow rate. This can be changing the drill string design and use larger drill pipes to achieve a higher flow rate, or adjusting drilling parameters and mud properties.

Another factor that have proven to aid in hole cleaning is pipe rotation, it is implied that the drill pipe rotation should be as high as possible in optimum hole cleaning conditions (A. Saasen 2002, T. Hemphill 2006). The positive effect of high drill pipe RPM on hole cleaning was also observed while drilling on the Statfjord field (B. Rasmussen 1991, T.E. Alfsen 1995). Good hole cleaning when sand bed and non-reactive particles are present can be achieved by pipe rotation because the drill pipe drags large portions of the cutting bed around from the low side to the high side where the fluid flow is greatest. The high fluid flow can disperse the cutting and good hole cleaning is achieved. It is unlikely that the drill pipe is centric in the wellbore and the eccentricity will further aid in removing cuttings. The pipe rotation drags fast moving fluid from the high side around to narrow low side where the fluid flow is retarded, due to its distance to the wellbore wall. The fluid that was originally on the low side is now forced out on the high side where the fluid flow is higher and will therefore be accelerated. This retardation and acceleration behavior creates an increase in the annular pressure drop ,which increase the shear stress on the surface of cutting beds (A. Saasen 2002).

Monitoring of torque and drag is used during drilling operations to determine hole cleaning by recording the pick-up, slack-off and rotating off bottom drill string weight prior to making a connection and with pumps off. The actual recording is compared to the predicted value and a close comparison indicate good hole cleaning. In addition the pick-up and slack-off weight trend is used to determine is the hole is loading up with cuttings or cleaning up. If there is a divergence trend between the actual pick-up and slack-off weights it indicates that the hole is loading up with cuttings. A convergence indicate that the hole is cleaning up. The diverging trend is explained by a higher pick-up weight due to the increased drag and reduced slack-off weight due to drag. Information from the first wiper trip and the diverging/converging trend is the basis for assessing the frequency of later wiper trips (G.J. Guild 1995).

### 3.2.4 Buoyancy

Archimedes (2112 B.C.) discovered that the buoyancy of a body equals the weight of the displaced fluid. Figure 6a shows the basic principle of buoyancy with a downward acting gravitational force and a buoyancy force, which is directed the opposite way. The projected height principle is used in buoyancy calculations, as it is only the pressure acting on the projected vertical area that contributes to buoyancy (E. Kaarstad 2011). Figure 6b show the projected height principle.




a) Forces acting on submerged body

b) Projected height principle

**Figure 8. Forces acting on submerged body**

The body of the object is subjected to a buoyant force that can be calculated by integrating the stress tensors over the surface area that is in contact with the fluid. The integration over the projected area can be challenging for irregular bodies. For an arbitrary body, one can assume a vertical prism with height, h. In this case the buoyant force is the difference between the top and bottom force acting on the prism. This assumption is only valid when some conditions are fulfilled. The fluid shall have access to the surface of the body and the body forces are external forces, which do not reflect the inner forces. In addition there must be a projected area to obtain buoyancy (E. Kaarstad 2011). The principle of buoyancy is used to correct the weight of the submerged object with an buoyancy factor. In a well, the buoyancy can applied in several way to obtain different objectives. For a drill string that is filled with the same mud that is in the well, the buoyancy factor is given by equation 3.5.

$$\beta = \frac{suspended\ weight\ in\ mud}{weight\ in\ air} = \frac{\rho_{steel} - \rho_{mud}}{\rho_{steel}} = 1 - \frac{\rho_{mud}}{\rho_{steel}} \tag{3.5}$$

During well operations like cementation and casing running the drill string and the wellbore have different fluids. Casings and liners can be filled with air or low-density fluid before running to obtain a lower buoyancy factor, which gives a lower hook load. Equation 3.6 gives the buoyancy factor in these cases.

$$\beta = 1 - \frac{\rho_o r_o^2 - \rho_i r_i^2}{\rho_{steel}(r_o^2 - r_i^2)} \tag{3.6}$$

Equation 3.7 gives the general expression for the effective buoyancy for a drill string composed of several different pipes sizes. The equation summarize the result of multiplying the weight in air of each pipe segment with the corresponding buoyancy factor from bottom to top. D is the TVD length for the given section.

$$\beta = 1 - \frac{\sum_{k=1}^{n} D_k(\rho_o R_k^2 - \rho_i r_k^2)}{\rho_{steel} \sum_{k=1}^{n} D_k(R_k^2 - r_k^2)} \tag{3.7}$$

Buoyancy have several applications in addition to reduce the apparent weight to allow running of tubular. In a stuck pipe situation, the maximum buoyancy method can be applied in the attempt to free the pipe. This method is based on the principle of reducing the drill string weight by displacing the drill string with a lighter fluid than the borehole, this action increase the available pulling force to free the pipe. It is then important that the differential pressure between the inside and outside of the drill string is below the maximum allowable pressure with respect to collapse.

### 3.2.5 Vibration

In general, drilling is making a hole in the ground by grinding or crushing the formation with a bit that is applied weight and rotation. This action subjects the drill sting to vibrations since the string is not stable. At low levels this vibration is harmless, but for high levels this vibration can cause numerous and severe problems. Some problems related to vibrations are washouts, twist-off, premature bit and downhole equipment failure. When drilling there are several sources that can excite the drill string. The amplitude of resultant drill string vibration will depend on the severity, the system damping and the proximity of the excitation frequency to the natural frequency of the drill string. The vibration amplitude will experience an amplification if the excitation source frequency is close to the natural frequency of the drill string. If the amplitude levels are high, then the drill string is subjected to fatigue loading which can result in material failure. A high level of vibrations may be present in the drill sting, independent of the drilling resonance, if there is a high level of excitation present. In drilling, there are three primary modes of vibrations, axial, torsional and lateral. Torsional vibration is a motion that causes twist/torque and relates to stick-slip. Lateral vibration is a side-to-side motion that relates to whirl. Axial vibration is a motion along the drill string axis and relates to bit bouncing. The different modes of vibration can interact with each other and result in a complex vibration combination that will be detrimental for the bit and drill string. The cause of vibration is the interaction between the bit and drill string with the formation under certain conditions and in certain formation sequences. Sources can excite vibration directly, trigger other vibration mechanisms, or induce a resonance or natural harmonic into the drill string. All the different sources have the potential to damage the bit, downhole equipment, wellbore quality and ROP (B.S. Aadnøy 2009).

The reduction of vibrations to increase bit and BHA life was very important at the Sakhalin project, where a round trip due to BHA failure could take five days. Leaving the wellbore open for five additional days can result in wellbore instability or in worst case a lost wellbore. For each run, the BHA components and bit were investigated for damage to identify potential improvements. Performance analysis for each BHA and bit were also performed and the improvements that were made resulted in record BHA runs (R.W.James 2012).

### 3.2.5.1 Stick-slip

Stick-slip usually occur when drilling with polycrystalline diamond compact (PDC) and is characterized by the periodic acceleration and deceleration of the bit and drill string rotation. The cause for this action is the frictional torque on the bit and BHA. The bit rotation and surface rotation speed are rarely the same due to the low torsional stiffness of the drill string. The string is always subjected to some torsion due to the friction at the bit and along the string. In stick-slip situations there will be a development of non-uniform bit rotation, where the bit momentarily stops and spins free. The drill strings continues to rotate when the bit stops and there will be an accumulation of energy in the string. The stored energy is released as the bit spins out and large vibrations that can be detrimental for the bit and BHA. Severe stick-slip situations can also trigger lateral BHA vibrations. Stick-slip situations can be detected on surface as large torque and RPM fluctuations. Impact on tools can be, bit damage, drill string twist-off, over-torqued connections (B.S. Aadnøy 2009). Some possible remedial actions to prevent stick-slip are:

- Stick-slip caused by bit-rock interaction; increase the RPM and decrease the WOB.
- Stick-slip caused by BHA-wellbore interaction; increase mud lubricity and use of roller reamers.

### 3.2.5.2 Whirl

Whirl can be occur for the bit, BHA or in a combination. This is a lateral vibration or walk, which is an eccentric rotation about a point that is not the geometrical center. This repeated impact of the bit and BHA with the wellbore can result in large and damaging stresses. Severe lateral vibrations can trigger both axial and axial vibrations. Bit whirl is a result of excessive side cutting forces, which cause PDC bit-wellbore gearing. The consequence of bit whirl is hole enlargement due to bit walk and accelerated bit failure due to large impact loading on the cutters. BHA whirl is the walk of the BHA around the hole and is caused by friction driven gearing of stabilizers or tool joint with the wellbore. Repeated impacts between BHA and wellbore can cause stabilizer and tool joint failure. There is no distinct method to detect whirl at the surface due to dampening of the lateral vibrations in the drill string. Some impacts caused by whirl are; cutter and or stabilizer damage, over-gauge hole, increase in downhole torque (B.S. Aadnøy 2009).

### 3.2.5.3 Bit bounce

This is an axial vibration that is caused by large WOB fluctuations, which in turn cause the bit to repeatedly lift off bottom and then drop down and impact the formation. Bit bouncing is normally related to rock bits, as these bits tends to create a pattern in the surface of the formation that can promote large vibrations. This axial vibration can damage the cutting structure of the bit and the bearing. Severe bit bouncing can trigger lateral BHA vibrations. Bit bouncing can be detected on surface by vibrations that make hoisting equipment shake, large WOB fluctuations and a reduction in ROP. A possible remedial action to mitigate bit bouncing can be changing drilling parameters like WOB and RPM (B.S. Aadnøy 2009).

### 3.2.5.4 Vibration Reducing Tool

BHA and bit damage due to drill string vibration is a major concern while drilling long wells. This was one of top priorities on the Sakhalin project where bit and BHA failure was reduced significantly through continuously improvement. For the longest wells a roundtrip can take several days, leaving the hole open and increasing the risk of wellbore instability. It is therefore desired to implement or improve tools and methods to reduce vibrations.

A company that have focused on this challenge is Tomax, their core business is to develop and deliver solutions to prevent drill string vibrations and stick-slip. The company have developed the AST tool shown in figure 9, which actively control the weight transmitted from string to bit to prevent stick-slip events. The tool is located in the BHA and all weight and torque goes through the tool before reaching the bit. This provide the tool the opportunity to automatically adjust the weight to prevent accumulation of torsional energy in the string.

**Figure 9. AST tool by TOMAX (TOMAX 2014)**

The tool was implemented in BHA configuration in the Oooguruk Project on the North Slope of Alaska, after the operator experience several bit and BHA failures when drilling through very abrasive siderite stingers. The project have ERD wells with 8,000 ft horizontal laterals that are drilled through claystone and sandstone with very abrasive siderite stingers. The tool was implemented for the 8-1/2" hole and for the 6-1/8" section. The result from the 8-1/2" section:

- 82 % reduction in torsional shocks
- Elimination of severe lateral shock and 80 % reduction in intermediate
- Higher ROP with reduced bit wear

The result from the 6-1/8" section:

- Drill pipe joint damage was eliminated, while the average in the three offset wells was 127 damaged drill pipe joints
- Number off bit for this section was reduced from 2-3 to 1

In this case the tool was implemented with great success and it shows how one single tool can significantly reduce the problems the operator experienced with drill string vibrations (M. Granhøy-Lieng 2011).

### 3.2.6 Wellbore instability

Wellbore instability can be caused by several factors, but what is common for all factors is the costly remedial action. Time spent on repairing the problem varies depending on the severity, but the operation fast become costly, with a daily rig rate of 5 MNOK for semi-submersibles on the Norwegian Continental Shelf. Wellbore instability include the following phenomena (B.S. Aadnøy 2009):

- Breakage of intact rock around the wellbore because of high stresses generated by the in-situ stress conditions or by sudden temperature changes
- Loosening of already fractured rock around the wellbore
- Growth of fractures from the wellbore into the formation, sometimes with significant mud loss
- Softening and breakage of the rock because of interactions with the drilling fluid
- Squeezing of soft rocks, such as salt, into the wellbore
- Activation of pre-existing faults that intersect the wellbore

The first five phenomena are very common and the consequence of occurrence can vary from negligible to detrimental for the well. Minor instability problems like small amounts of rock breakage that caves into the wellbore is a small problem since the caving will be handled with normal hole cleaning. If the amount of rocks that break of increase the problem will become serious as it creates problems for cementation and hole cleaning. The large amount of rock can pack-off the drill string and result in increased torque and drag and increased bottomhole pressure. The consequence of this can be stuck pipe or pipe twist-off that in worst-case scenario can result in a sidetrack (B.S. Aadnøy 2009).

Stuck pipe is one of the major problems related to wellbore instability and relates to two different stuck pipe mechanisms, differential sticking or mechanical sticking. Differential sticking occur in permeable formations where there is a large overpressure and build-up of filter cake. The drill sting become embedded in this thick filter cake and the large differential overpressure makes it difficult to free the pipe form the borehole wall. The problem is further increased if the drill string is allowed to stay static over a period, this is why there are created best practices for drill pipe connections to avoid stuck pipe. Mechanical stuck pipe can occur because of drilling induced problems or wellbore instability. Drilling induced problems are mostly related to key seating, inadequate hole cleaning and under-gauge hole. While wellbore instability mainly relates rocks that cave into the wellbore and pack of the drill string or interactions between reactive shale and drilling fluid can cause the shale to swell and close clog the wellbore (T.A. Inglis 1987).

# 4 Hole in One Producer

Hole in One Producer (HOP) is an innovative drilling and completion solution under development by IRIS. The solutions represents a large leap forward compared to conventional wells and if successfully implemented in the future, it can be a game changer in the industry. The HOP concept is based on a dual casing string, traction units with expandable packers and the completion equipment in the drill string. After drilling to target, only minor actions are necessary before the well is ready to produce hydrocarbons.  A more detailed description of the functionality and components in this concept comes in the later subchapters. The evolvement of HOP over the last years have moved the concept from full-bore casing drilling towards using a conventional drilled 9-5/8” casing as mother hole and drill further with HOP and complete it as a liner application. The HOP drill string is run to casing shoe depth and then the string is crossed over to a regular wired drill pipe before drilling is commenced. The solution limits the length of the well to twice the length of mother hole (B.Aas 2008). This limitation still provides wells with a potential of reaching the 20 km mark, as several wells on the Sakhalin project have 9-5/8” liners on measured depth over 9,000 m and in OP-11 the liner were placed at 10,756 m (M. W. Walker 2012, V.P.Gupta 2014). Over the two last decades, operators have pushed the limits of conventional drilling technology to increase well length, but as shown in Table 1, the reach have not increased much the last decade. New technology and methods seems to be crucial to increase the length towards 15 km and further.

## 4.1 Functionality

The HOP concept is an innovative solution where the well can produce almost directly after drilling to TD, without replacing the drill string. An overview of the functionality of the concept is provided here, and details will be elaborated in the following sub chapters. The concept consists of a dual casing string that include the completion equipment and the string is run in hole with traction units along the string. Figure 10 shows the HOP string, where the dual casing is 12 m long and the traction units are approximately 10 meters long and are located each 120 m. The string will be equipped with advanced gauge technology to measure among other drill string tension. Measuring the tension in the string is a method to avoid any overload on a specific part that can result in mechanical failure. If one traction unit fail or a packer fails in expanded state, the back of the unit will be in compression and the front will be in tension due to the pulling force provided by the other units. By adjusting the pulling force to the adjacent units, the string is not subjected to such high loads.

In operation, the casing and traction units are connected and run in hole down to the previous casing shoe, then a crossover is used to connect the string to a wired drill pipe. Wired pipe is used to transmit electrical signals to the down hole equipment. To provide traction and well control the system uses traction units that have two elastic packers, which are operated by pressure provided from local hydraulic oil reservoirs in the string. One of the packers are always inflated in drilling to provide traction and zonal isolation, while the other packer is retracted and repositioned to be inflated before the previous is deflated. The packers are fixed on a sliding sleeve with a 0.5 m stroke distance. This method keeps the dual casing anchored to wellbore wall at all times in addition to provide a continuous traction and ensure that at all times one of the packers are inflated. The drilling assembly is relatively short and have an own piston with hydraulic oil reservoir to provide a constant WOB. Another benefit is that the short drilling assembly is mounted in front of an anchored string, which will minimize damaging drill string vibrations. This is a crucial feature of the concept due to the importance of drilling the whole well with only one bit. Mud is sent down the wired pipe and through the crossover into the channel between outer and inner channel and the return is sent through the inner casing, through the crossover and into annulus as in regular drilling operations. Mud motor is used as in conventional drilling operations to power MWD and rotation of the bit.

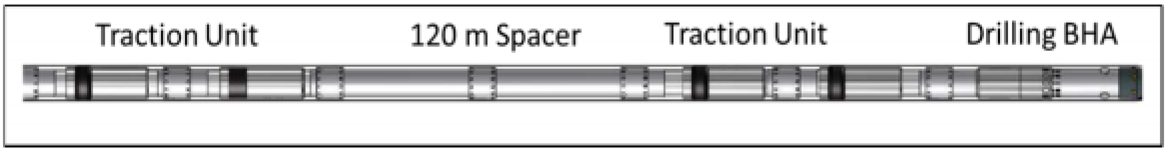



Figure 10. HOP String (D. Gardner 2013)

The concept will utilize MPD technology to drill at pore pressure or slightly above, to minimize the impact on the surrounding formations. In addition, the frictional pressure drop inside the narrow mud channel will be high in long wells and results in an elevated ECD toward the fracture pressure if drilling with an overbalanced mud. A normal action for this is to drill with an underbalanced mud or slightly above pore pressure. Another reason for this is that the packers will provide zonal isolation, which means that there will not be any mud circulation in the outer annulus. This will make the pressure in each section to change toward pore pressure with time. Sand screens and completion equipment are included in the string so that after reaching TD only minor operations is necessary before staring production. This will include changing the wired pipe to a production tubing and cleaning the well (B.Aas 2008, D. Gardner 2013).

### 4.1.1 Dual Casing

The drilling will start from the previous set 9-5/8” casing shoe by using an 8-1/2” drilling bit. Table 8 shows the dual casing component properties. For simplicity, it is assumed that the casings are slick, even though all casings will have some increase in outer diameter due to the tool joint.

| Casing | OD [inch] | ID [inch] | Weight [lb/ft] |
|---|---|---|---|
| Inner | 4-1/2 | 4 | 11.6 |
| Outer | 7-5/8 | 6.765 | 33.7 |

Table 8. Dual Casing Properties (S. Stokka 2014)

The inner casing is placed eccentric in the outer casing to provide a larger passage for the mud that is sent down the string. Due to the temperature effects that the dual casing is subjected to during drilling and production the inner casing will only be fixed to the outer casing in the low end, this is to provide flexibility for the inner casing to contract or expand. This is necessary since there will be a temperature difference between mud sent down and mud return, which will induce tension in the string and make it elongate. The inner casings is stabbed into each other during a connection and sealing is obtained with rubber or elastomer seal. Between the drilling assembly and the lowest traction unit there are inlet ports where the mud return can access the inner casing, these ports will be equipped with a type of valves that close if mud pumping stops. There will also be a valve in the mud feed line that close if the mud pumping stops, like during dill pipe connections.

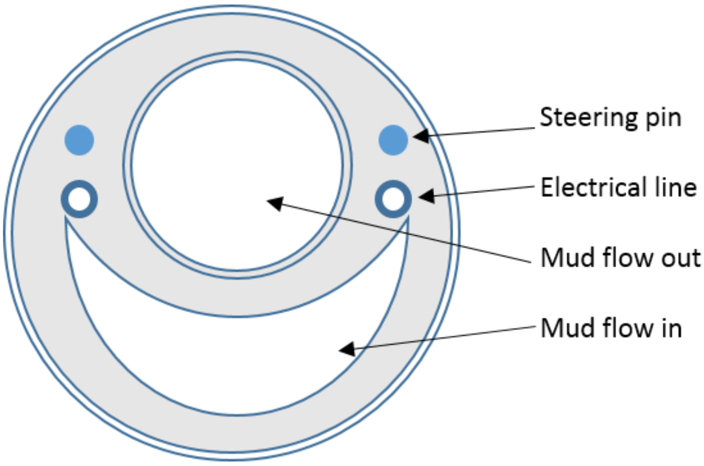



Figure 11. Dual casing

The initial design of the dual casing is as shown in Figure 11, with two steering pins for the proper alignment during connection and two electrical lines. This design eliminates the conventional method to connect two pipes by torqueing up the connection by rotation. An alternative method to connect the casings is to use torque free union type tool joints. The connection type and method is still under development and is one of the technological challenges with the concept (B.Aas 2008).

### 4.1.2 Traction Unit

The traction unit is with the present design 10 m long and have two 8” elastic packers mounted on sliding sleeves. One packer is inflated at all time during the operation to provide traction and zonal isolation, while the other packer will reposition before expansion. This provide a continuous downward motion and results in smooth drilling. Figure 12 shows how hydraulic pressure actuates the packer expansion by applying pressure on metal sleeves located on each side of the packer (red). This makes the packer expand radially until it meet the wellbore wall with the designated expansion load. The required expansion load will depend on temperature and required force to slide the string (D. Gardner 2013).

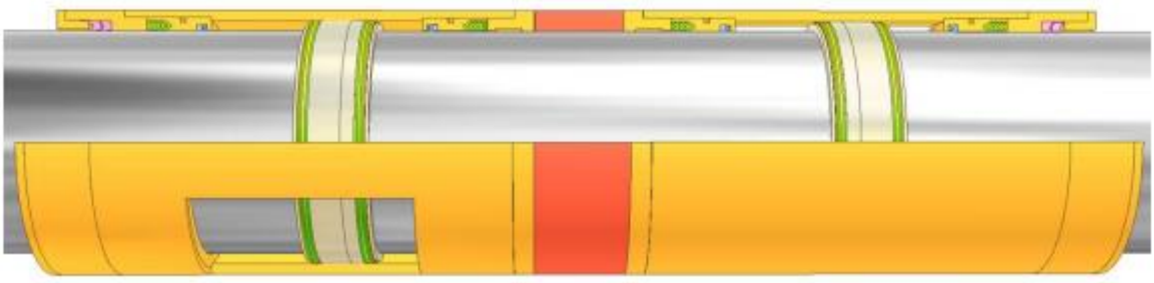


Figure 12. Expansion of packer (D. Gardner 2013)

The concept require a packer that can withstand being inflated and deflated several thousand times, which is very different from the conventional packers. In the well the minimum distance between the wellbore and the string will be at the packers. It is therefore important that the packer will return to its original deflated size and is not plastically deformed. Thus, an automated purpose build rig were built to perform a full-scale test of a 12-1/4” HOP packer. The packer was subjected to 5000 cycles, with different expansion loads and temperatures.

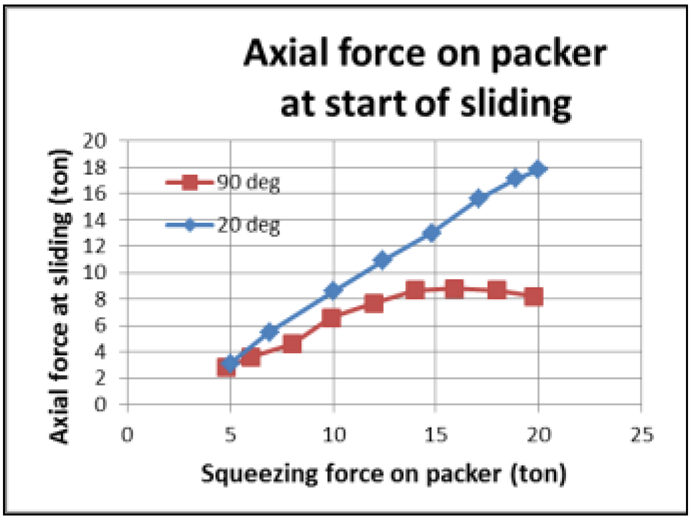



Figure 13. Axial force on packer at start of sliding (D. Gardner 2013)

The result from this testing is shown in Figure 13. This shows that the traction force decrease as the temperature increase, due to the reduction in packer friction properties with increasing temperature. A very positive result from this test is that no significant packer wear was observed. This shows that it is possible to develop packers that can withstand the cyclic loading, but further testing is needed to find a packer material that is less influenced by temperature.

The traction force in the HOP liner concept is delivered by a piston with a radial width of 0.015 m that is mounted on the unit with a radial width of 0.0968 m. A hydraulic pressure on 100 bar is applied to the piston.

$$F = P * A = 100^5 * \pi * ((0.0968 + 0.015)^2 - 0.0968^2) = 98{,}300\ N$$

The piston delivers a traction force of 98.3 KN or 10 tons for each packer in a unit. The total available traction force will be much larger when summarizing the contributions from the other traction units.

### 4.1.3 Drilling

A vital part of the HOP concept is that the string shall drill to TD in one run. To sets strict requirements to the performance and quality of the down hole equipment that are used, including MWD and drill bit. This section will focus the performance of drill bit and not on MWD. The dual casing is anchored to the wellbore wall with packers and provide downward traction, while the drilling assembly have an own piston that provide a constant WOB. The distance between the last traction unit to the bit is relatively short and aid in eliminating damaging vibrations. In the HOP concept, the focus for drilling is not to obtain maximum ROP, but instead to obtain the optimum efficiency with respect to BHA and bit wear. A PDC bit would be most suitable for drilling, as it have no moving parts that can break. In addition, the PDC cuts the formation instead of crushing it like the roller cone bits, which require less WOB. It will be possible to deliver very high WOB due to the large pulling force that the traction units provide, but this may induce extra stress in the string and may become a disadvantage with respect to durability. In conventional drilling, PDC bits introduce stick-slip, while roller cone bits introduce bit bouncing, but as mentioned this is not considered a problem for the HOP concept. Substantially research and development is required to design and develop a bit that fulfil the HOP requirements. If the HOP section is 9,000 m, then drilling would last for 38 days, with an estimated ROP of 10 m/hr. This illustrates the necessity of a durable BHA and bit. Caving can occur close to the bit while drilling in loose formations and these rock pieces will be too large to enter the mud return port. It is assumed that the caving will be crushed by the bit or be broken up by the drill stem rotation. Cuttings produced while drilling the formation will normally be relatively small due to the low WOB that is required to reduce bit wear, and should not be a problem for an estimated 2" inlet port. In addition, the traction units provide sufficient force to push the drill string through the loose rocks or caving. There will be several inlet ports for the return mud and in some way, it will be possible to reverse the flow if many inlet ports become plugged. As the well is being drilled it is normally required to do some directional drilling also to change the well path. One possible solution for this will be to a kind of bend sub technology. In conventional drilling the bend sub is installed above the down hole motor and have an offset angle that forces the bit and motor to drill a specific direction when string rotation is stopped. For the HOP system the string will never rotate as it is anchored to the wellbore wall and therefore directional drilling can be obtained by changing the drill stem angle. This method does not induces extra force on the bit side as in rotary drilling and may be a good solution with respect to bit durability (T.A. Inglis 1987, B.Aas 2008).

## 4.2 Well Control

Well control is defined as a "*collective expression for all measures that can be applied to prevent uncontrolled release of wellbore fluids to the external environment or uncontrolled underground flow*"(NORSOK 2013). During drilling operations, many events can occur and influence the performance of well barrier elements. These elements is combined to provide two independent barriers that together give the necessary well integrity to ensure safe operations according to NORSOK D-010, and here well integrity is defined as "*application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids and well fluids throughout the life cycle of a well*". The worst case scenario for drilling operations is that a failure prevents correctly handling of a kick with a large blowout as the consequence. Large blowout accidents have the potential to be very detrimental and many people have died in such accidents in the past. The Macondo blowout in 2010 where eleven persons died is an example of the criticality of well control (J. E. Vinnem 2014). A failure can be caused by human error, technical or mechanical failure, organizational failure or a combination of these. It is therefore developed standards and regulations for drilling operations where compliance to these can aid the operator in prevention of major incidents.

For the HOP concept it is possible to divide well control into three different scenarios, which is deploying the HOP string into the well, drilling and production. The well integrity is maintained during deployment of the string by the verified cement at previous set casing shoe and the overbalanced fluid in the well. This complies with the two independent barrier philosophy in NORSOK D-010. During drilling a MPD system will be utilized so that the wired drill pipe will be stripped in and annulus is sealed off. This provide an effective method to adjust the annulus pressure if any abnormalities should occur or if formation fluid should migrate into annulus. A key factor in the concept is that the string is pulled by traction units with a packer pair that is inflated and deflated in a specific pattern to ensure that one packer is inflated and provide traction at all time. At the same time, the inflated packer divide the well annuls up in sections and close it off. This effectively isolate different formations and prevent any direct communication along annulus. The packers will inflate and deflate in a cyclic pattern, so fluid from one section can flow to the previous if there is a pressure difference over the unit. Different well control scenarios is elaborated in the following sub chapters.

### 4.2.1 Gas Migration in Annulus

The HOP liner application is used to drill a very long section in one run, it will therefore be likely that the drill string will penetrate some formations that contain high pressure gas or have a higher pore pressure. As the string penetrate this formation a pressure difference occur over the traction unit and during the packer pair cyclic expansion pattern some of the gas can migrate into the previous section. A study from IRIS have addressed this issue for a 10” HOP string in a 12-1/4” hole, where there is a 250 bar high pressure zone and 200 bar at the mother casing shoe. As a worst case scenario one assume that the high pressure zone is 1,200 m away from the casing shoe and there is no permeable formations between the casing shoe and the high pressure zone. Assumptions made for the calculations in the study is:

- 12 m distance between packers
- 0.5 m stroke length
- ROP of 10 m/hr
- 0.5/GPa effective compressibility of the system
- Lowest well point at casing shoe and inclined towards the bit

The study estimates that the gas-liquid surface will reach the casing shoe after 400 days and that if the well is 30 km the gas-liquid surface would have moved 125 m. It is therefore anticipated that no high pressure gas will reach surface when drilling a 30 km long well, as long as the high pressure zone is more than 125 m away from the casing shoe (B. Aas 2013).

### 4.2.2 Kick

The well is drilled using a mud weight close to pore pressure to reduce the ECD that can become quite large and approach fracture pressure. During a drill pipe connection the mud circulation stops and the pressure development in the bit region is monitored to obtain more information about the pore pressure. This information is used condition the drilling mud to the correct weight and prevent unintended influx from the formation while drilling. The mud weight alone is not an element that can prevent a kick from occurring since several events can cause a kick while drilling with the HOP concept. The formation can be naturally fractured or contain large caves so that a lost circulation event can occur, this lowers the pressure in bit section and influx from the formation occur. The kick can be circulated out through the inner string and in annulus between drill pipe and previous set casing to surface. The MPD technology ensures that the annulus pressure is below the collapse pressure of the drill pipe and the burst pressure of the previous set casing. If there should be a leak in the inner casing which is the return line, then the kick could enter the annulus between the inner and outer casing. This is the mud feed line from surface. Conventional kick handling methods are then used (B.Aas 2008).

## 4.3 Wellbore Instability

The pressure in the wellbore induce stress in the surrounding formations, which can result in borehole fracturing at high pressure or collapse at low pressure. For the HOP case where the drilling is performed with a pore pressure balanced mud this is not anticipated to be a large concern. The elements that are of concern will be more related to interaction between mud and formation and specific events that only occur in certain formations. Shale is the formation mostly encountered when drilling a well and can be responsible for large drilling problems. Water is absorbed into the shale structure and make it swell to the extent that it can clog of the borehole. This is a known phenomenon and a good method to prevent swelling is to use inhibitive drilling mud, where OBM systems have proved to be better than WBM systems. In addition, the OBM system will create a thin and strong filter cake that prevent fluid loss while drilling. In brittle shale, the water is absorbed along the fracture plane, which weakens the structure and large rock fragments can fall into the borehole (T.A. Inglis 1987). OBM system is therefore the primary choice for HOP drilling. Salt formations have a plastically nature and are traditionally drilled using a high mud weight to prevent the formation creeping into the borehole and creating challenges. These formations are also known for introducing additional drilling problems like loss circulation, washouts and corrosion. Conventional drilling have the opportunity to drill with a high mud weight and keep a high pressure in the whole section to prevent the formation to plastically deform, but for the HOP this is not possible. It is therefore wiser to avoid the salt formation. Plastic chalk formations should also be avoided. The traction units that are used provide large amount of pulling force and should be able to pull the string past any caved in or collapsed formations (B.Aas 2008).

## 4.4 Hydraulics

The intention of the HOP concept is to drill and complete wells far beyond the reach of conventional drilling methods. To do so the hydraulics must be optimized to ensure a sufficient flow rate to achieve good hole cleaning without exceeding the fracture gradient limit. This is a known problem in long reach wells where the flow rate have become too low due to the frictional pressure drop in the system. The hydraulic calculation in this case will be with respect to frictional pressure loss in tubing, annulus and across the bit to determine the necessary pump pressure. The pump pressure needs to lower than the drill pipe burst pressure including a safety factor. Many of the modern mud pumps used on drilling rigs have a 7500 Psi (517 bar) pump capacity, but it is common to keep the operating pump pressure below 290 bar in conventional drilling to prevent premature pump failure. On the Sakhalin project the operator is using a 12-p-160 triplex mud pump with a pressure rating of 7,500 psi with a 4.5" liner and 297 GPM. More information for mud pump performance with different liner sizes and flow rates are shown in Figure 14. The pump performance is based on 90% mechanical efficiency and 100% volumetric efficiency (NOV 2014).

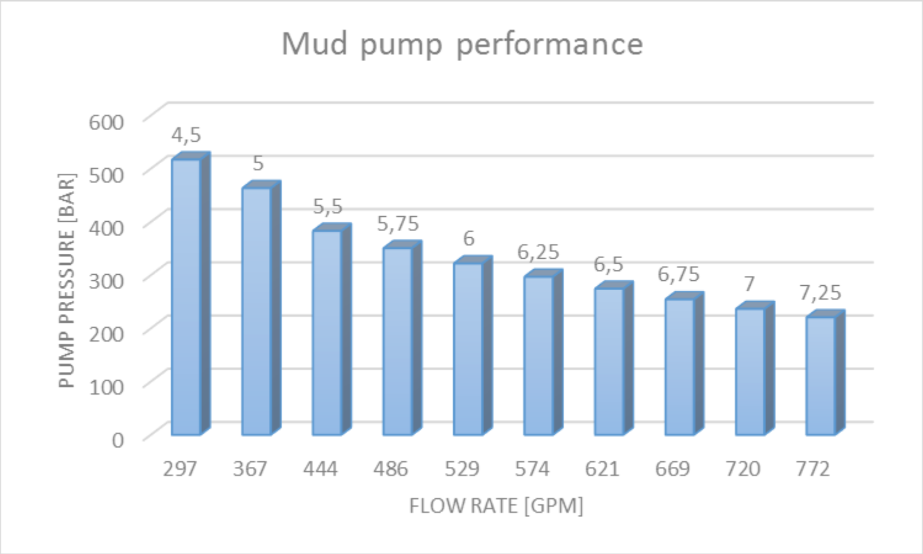



Figure 14. 12-P-160 Mud pump performance (NOV 2014)

For the HOP concept the flow path for the mud in the system is:

- Down the inside of a wired drill pipe
- Through a crossover and into the inner casing
- Down the inner casing
- Through the bit
- In through inlet ports
- Up the annulus between inner and outer casing
- Through the crossover and into annulus between dual casing and previous set casing
- Up annulus

### 4.4.1 Frictional Pressure Drop in HOP

Several simplifications and assumptions are made in friction pressure loss calculations for the HOP drilling case. This is done to obtain an illustration of how the hydraulics of the concept will behave. The simplifications and assumptions made are:

- Assume smooth pipe in Haaland friction model
- Assume a fixed viscosity
- Assume constant mud density
- Assume similar frictional pressure drop in inlet and crossover as in nozzle calculation
- Assume that the return channel in dual casing is 80 % of available area
- Neglect change in diameter at tool joint to simplify the calculations

The equations used for the pressure drop calculations is:

Reynolds number:

$$Re = \frac{\rho * u * D}{\mu} \tag{4.1}$$

Haaland explicit friction factor equation assuming smooth pipe (R.W. Time 2013):

$$\frac{1}{\sqrt{f}} \approx -1.8 * log_{10}(\frac{6.9}{Re}) \tag{4.2}$$

Frictional pressure drop:

$$P_f = \frac{1}{D} * f * \frac{1}{2} * \rho * u^2 \tag{4.3}$$

The pressure drop across the drill bit nozzles is calculated using equation 3.7 and the same equation is used to calculate pressure drop across inlet ports and the crossover.

Calculations are based on HOP drilling out of a 9-5/8” mother casing and the tubular used is shown in Table 9.

| Tubular | OD [m] | ID [m] | Inner Area [$m^2$] | Outer Area [$m^2$] | Weight [lbf/ft] |
|---|---|---|---|---|---|
| Inner HOP | 0.1143 | 0.1016 | 0.0081 | 0.0103 | 11.6 |
| Outer HOP | 0.1937 | 0.1148 | 0.0103 | 0.0295 | 33.7 |
| 5-7/8” DP | 0.1492 | 0.1309 | 0.0135 | 0.0175 | 27.1 |
| Annulus | N/A | 0.2445 | 0.0470 | N/A | |

**Table 9. Tubular properties in HOP**

The setting depth of the mother casing is selected to be 7,000, 8,000 and 9,000 m, which results in a well that is twice as long with the HOP concept. By using the different setting depth one obtain the most important trends related to increasing the well length. The hydraulic system is influenced by several factors and by adjusting one parameter the frictional pressure drop may become very different and different flow rates and viscosities are used to illustrate this. Typical flow rates for the 8-1/2” hole in ERD wells are in the range of 350-650 GPM, depending on the ECD behavior with respect to the formation fracture limit and the pump pressure (M.L. Payne 1994, T.E. Alfsen 1995, D.A.Cocking 1997, M.W. Walker 2009). Figure 15 shows the frictional pressure drop calculations when the pump pressure is 450 GPM. The maximum pump pressure from Figure 14 for the specific flow rate and the normal operating pump pressure in conventional drilling is also included.

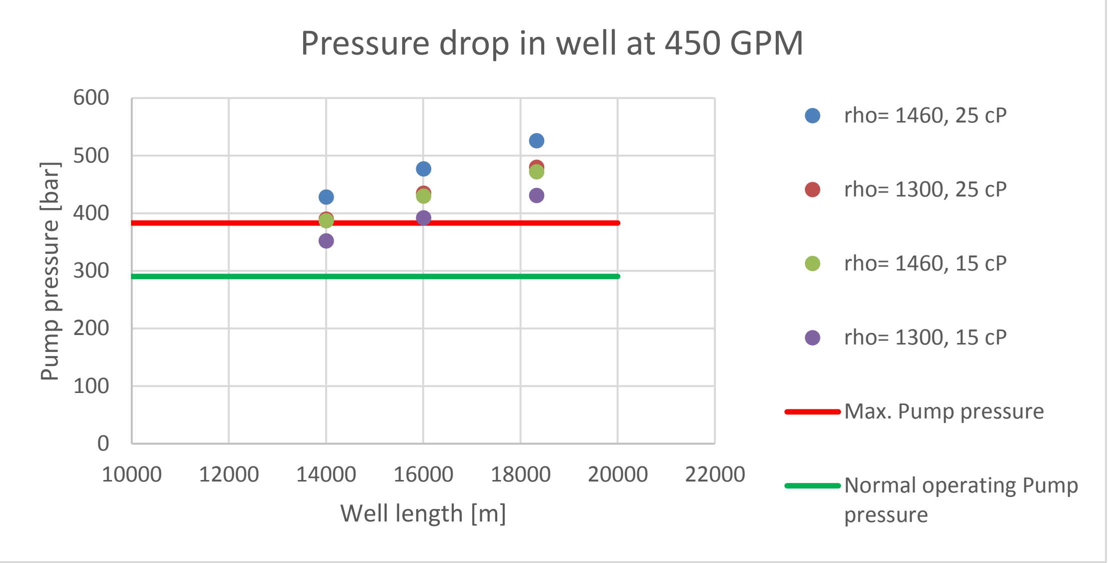



**Figure 15. Pressure drop in well at 450 GPM**

The figure shows that it is only possible drill 14,000 m with the mud properties given in this example, if one is limited by the mud pump performance. The drill pipe used to deploy the HOP system is subjected to the largest differential pressure and the pump pressure must be controlled against the drill pipe burst pressure. As mentioned the system uses a wired drill pipe to deploy the system and this pipe is burst rated to a differential pressure of 1038 bar (NOV 2014). Assuming a safety factor of 2.0 the maximum allowable differential pressure is 519 bar, which is higher than the maximum pump pressure.

The same calculations is performed for a flow rate on 350 GPM and the result is shown in Figure 16. Here it is shown that it is possible to have the selected flow rate and be below normal operating pump pressure for a 18,000 m long well.

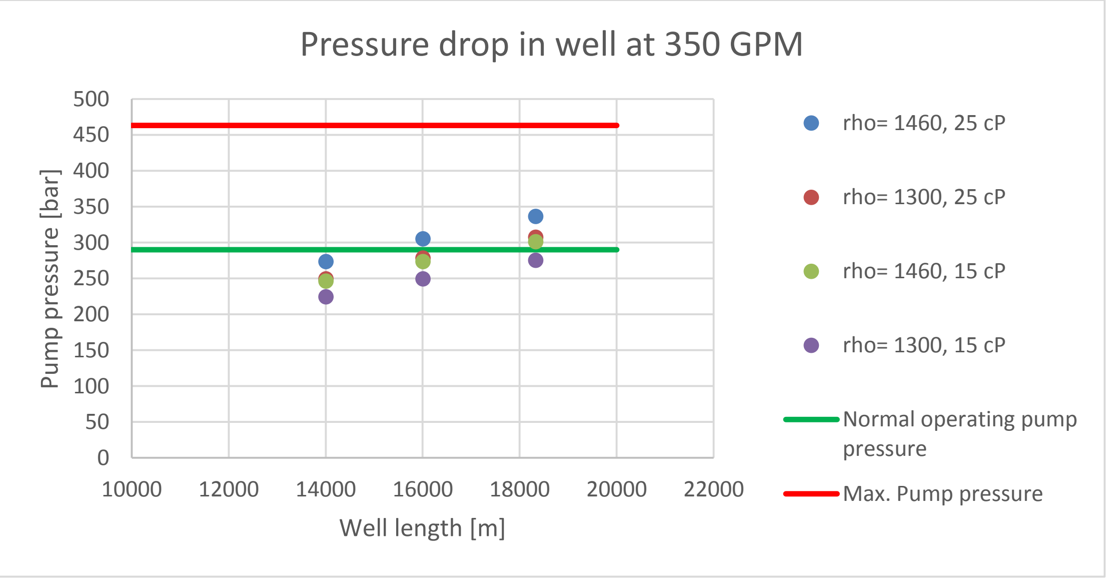



**Figure 16. Pressure drop in well at 350 GPM**

The calculations show that the flow rate is a very important parameter and reducing the flow rate from 450 to 350 GPM with a 1.46 sg mud, then the associated pump pressure is decreased with 190 bar. It is also shown from the two figures, that one approximately achieve the same reduction in pump pressure by decreasing the mud weight by 0.15sg or reducing the viscosity from 25 cP to 15 cP.

The wired drill string is burst rated to operate with the standpipe pressures on drilling rig, which are typically 5,000 Psi and 7,500 Psi on newer rigs. In the same way the HOP dual casing string needs to be design to withstand these loads to avoid any failures.

Many factors in the well is influenced by each other and changes made for optimizing for one element can be damaging for another element. An illustration of influence between several important elements in a well is provided in Table 10 (A. Saasen 2002, B.S. Aadnøy 2010, University of Stavanger 2012). The table shows if it is beneficial with high or low value on the parameter when optimizing. Pipe clearance is the area between the drill pipe and casing or formation. As an example one can optimize with respect to hole cleaning, with a high mud weight, high viscosity to keep the cuttings in suspension and small pipe diameter clearance to achieve turbulent flow. This optimization will be a large disadvantage for the hydraulics and be a disadvantage for torque and drag, where the small pipe clearance and high viscosity will increase torque and drag in the well.

| Element | Mud weight | Viscosity | Pipe diameter |
|---|---|---|---|
| Wellbore stability | High | Low | Large pipe clearance |
| Hydraulics | Low | Low | Large pipes and clearance |
| Hole cleaning | High | High | Small pipe clearance |
| Torque and Drag | High | Low | Large pipe clearance |

**Table 10. Advantages for given elements**

This shows how optimization of one element is not beneficial for the whole system, and that the optimization instead is a compromise between several elements in order to achieve the best overall performance.

## 4.5 Design Issues

The HOP drilling method is very different form conventional drilling and is based on development of new technology for almost every component in the concept. All elements needs to be designed, tested and verified as separate components before the specific system is assembled and tested. Some of the key elements in the concept is (IRIS 2009):

- Traction unit
- Packer
- Bit and directional control
- Dual string connection
- Control system
- Closing valves for inlet ports
- Integrity of inner string connection seal
- Integrity of the system during productions
- Production equipment

The system needs to be made out of components of the highest quality, as it will be very difficult to perform intervention or workover in the well. It is therefore required that the system is very durable and include much redundancy to handle eventual failures without compromising the integrity of the well. The need for redundancy or means of replacing components can be illustrated by using the closing valve in the inlet port as an example. This valve is a well barrier element during both drilling and production. The valve function during drilling is to close during events without mud circulation, like drill pipe connections, during production is shall close and seal the inlet port and prevent inflow. The valve is therefore located in a very harsh environment where it is subjected to erosional wear from particles in the mud, high temperatures and high pressures. The different loads that the valve is subjected to, will over time increase the risk of leakage or failure and a contingency plan should be derived for replacement of the valve or including system redundancy. The same parallel can be drawn for all the key elements, and it indicates the complexity of developing a concept that relies on new and unproven technology and methods.

The frictional pressure drop in a HOP well will be very high as shown in the previous section and thus the dual casing needs to be design to withstand this load. The HOP connection shall withstand large tensile and compressive loads in addition to achieve sufficient seal. The connection sealing mechanism will be different from conventional drill pipes since there will not be any possibilities to rotate the dual casings and torque them up. By applying torque to the connection of conventional tubular one obtain a metal-to-metal seal, as shown in Figure 17 (K. Hamilton 2009).

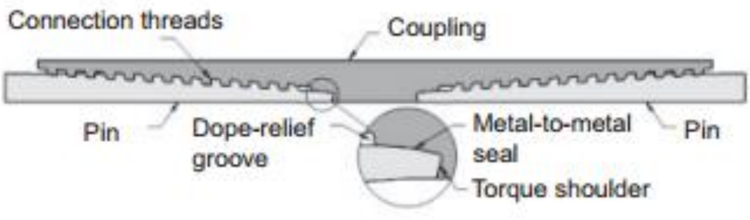



**Figure 17. Cross-sectional view of a typical premium connection (K. Hamilton 2009)**

## 4.6 Compliance to NORSOK D-010

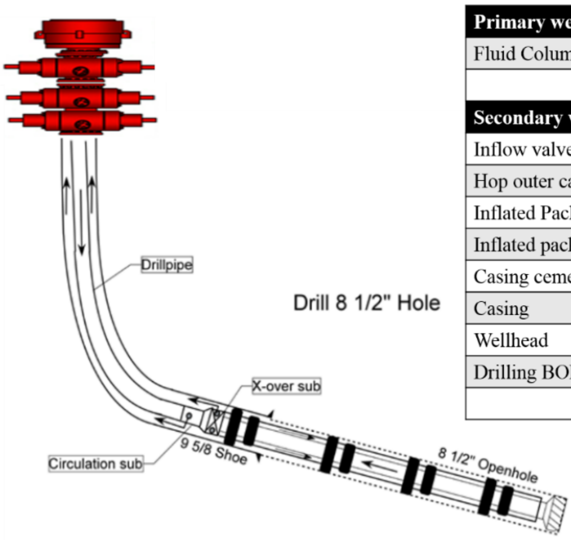
In this section the HOP drilling concept is evaluated with respect to NORSOK D-010 which is the standard for well integrity in drilling and well operations. The standard is used to provide the minimum requirements to ensure that the operations comply with applicable laws and regulations. An advantage with the standard is that operators are not limited by the NORSOK standard in selecting a specific solution for their work, but they are obliged to provide documentation for their solutions compliance with given performance targets in the standard. The non-limiting nature of NORSOK standards encourages operators to implement new technology and improve existing procedures for ultimately achieving better HSE and higher hydrocarbon recovery on the NCS (NORSOK 2013).

The standard specified that there shall be two well barriers present at all times when there can be inflow from a hydrocarbon containing formation with potential to flow to surface or in presence of abnormally pressured formation with potential to flow to surface. This introduces the concept of primary and secondary well barrier. Primary well barrier is the well barrier located closest to the pressurized hydrocarbon acting as the first line of defense. The secondary well barrier shall prevent an incident from occurring or from escalating in the event of primary well barrier failure. Even though it is specified with two independent well barriers the standard opens for the opportunity of common well barrier elements if a risk analysis is performed and risk reducing measures are applied (NORSOK 2013).

Logging tools like MWD/LWD is included in the HOP drill string and these tools can contain a radioactive source used to measure formation properties. Some logs that can be done using radioactive sources are gamma-ray, density and neutron (T.A. Inglis 1987, Karl Audun Lehne 2012, Petrowiki 2013). The Activity regulation emphasis that a radioactive source shall not be planned abandoned in the well, and it shall therefore be a planned action for retrieving the source from the HOP drill string (PTIL 2014). For the HOP concept, the design will require the source to be located in such a way that it can be retrieved easy after reaching TD, or using logging tools without radioactive sources.

### 4.6.1 HOP Well Integrity

First the well is conventional drilled until the 9-5/8” casing is set. The well is filled with a heavy mud as a primary well barrier and the secondary barrier is the tested casing shoe, casing, wellhead and drilling BOP as in conventional operations. The HOP concept is to deploy the HOP string down to the casing shoe and crossover to a wired drill string before drilling starts. This solution removes the need of a BOP that can cut a dual casing or close pipe rams across the traction unit. The HOP string is also deploy into the well while the two independent well barrier philosophy is maintained.




| | |
|---|---|
| **Primary well barrier** | |
| Fluid Column | |
| | |
| **Secondary well barrier** | |
| Inflow valve | |
| Hop outer casing | |
| Inflated Packer | |
| Inflated packers in casing | |
| Casing cement | |
| Casing | |
| Wellhead | |
| Drilling BOP | |
| | |

**Figure 18. Well barriers in HOP drilling**

Figure 18 shows how the well barriers when drilling with the HOP concept can be. The HOP outer casing is defined as a secondary barrier and it include all the production equipment, such as inflow control devices, sliding sleeves, etc. The complexity of the system introduce difficulties in defining each individual well barrier element and the different elements are therefore compiled within the HOP outer casing in order to simplify the case.

### 4.6.2 HOP Failure in Hole

If some crucial downhole equipment should fail during drilling and making further advancement impossible, one have in principle two choices, either pull the string out of hole or detach at crossover and leave the HOP string. What the best option will be is dependent on the scenario and an abandonment plan following the well path should be derived in advance of drilling.

As case example one can assume that the well have been drilled several kilometers away from the casing shoe. Penetrating several permeable formations that have abnormal pressure or is hydrocarbon containing. The different zones are effectively isolated from each other while drilling due to the packers inflating cyclic pattern. The well profile for the example case is shown in Figure 19.

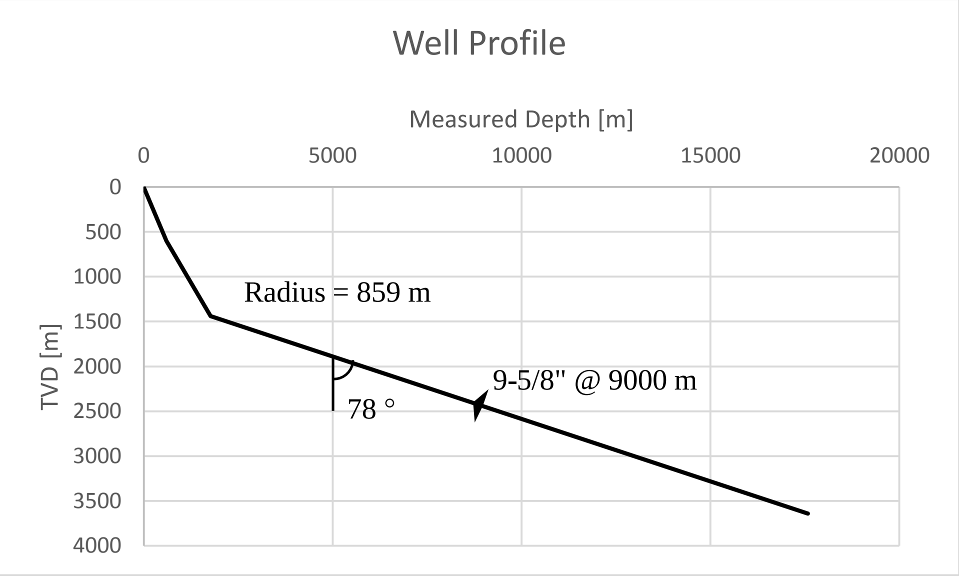



**Figure 19. HOP well profile**

The case of pulling the string out of hole is investigated first. All the HOP traction packers is deflated before the string can be pulled to surface, meaning that the annulus is open. This calls for a heavy mud that can prevent inflow from formations along the well path. The hydrostatic mud pressure needs to be above pore pressure and below fracture pressure in addition to below casing burst pressure. A long well like this will most likely be drilled through several formations that have an abnormal pressure which eliminates the possibility of opening annulus without experiencing cross flow, fractures, loss incidents, etc. The next thing to evaluate is the drag associated with hoisting the string out of the well. Equations 3.1 and 3.2 is used to calculate the hoisting load when the friction factor is 0.2, mud weight on 1.30 sg and tubular properties as in Table 9. The Hop string is 9,000 m and is followed by 8,578 m of 5-7/8” wired drill pipe. The results from the drag calculation is shown in Figure 20, and the pull force required is 4,301 kN. The 5-7/8” wired drill pipe have a tensile strength of 3900 kN (875,500 lbs) and will in this case be too weak (NOV 2014). It may be possible to disconnect at the crossover and replace the wired drill pipe with a stronger wired drill pipe that can withstand the tensional load. The dual casing connections is not designed yet and currently no tensile rating for the connection is forecasted.

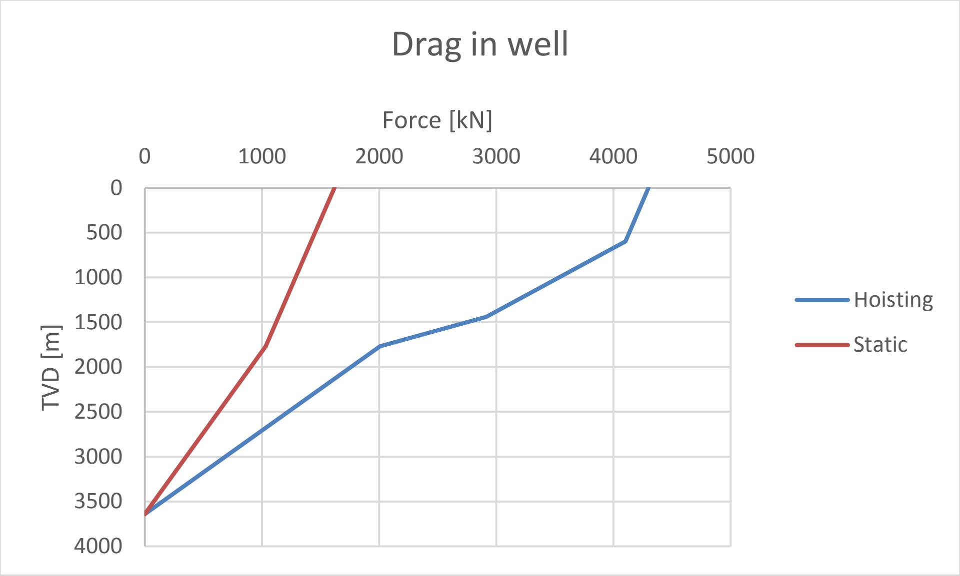



**Figure 20. Drag in HOP well**

If the string can not be retrieved the only choice is to disconnect at the crossover and leave the HOP string in hole. The different formations that is penetrated by the string needs to be plug and abandoned according to the NORSOK D-010. A tested and verified method to plug the permeable formations needs to derived, currently available technologies that may be applicable is the perforate, wash and cement method by Hydrawell or section mill in order to set the plug (T.E. Ferg 2011).

## 4.7 Qualification of New Technology

The HOP drilling and production concept is based on development of new technology and methods to achieve its intended function. The different components and methods needs to be qualified to provide evidence to ensure that the technology will function within the associated requirements with an acceptable level of confidence. Many of components used will act as a well barrier element and must be qualified within the applicable regulations and standards. The qualification of well barrier elements is an important measure in ensuring better integrity in oil and gas wells in the industry (B. Vignes 2011). The HOP drill string is used for both drilling and producing the well. The qualification of the different components and the whole system to ensure well integrity over the wells lifespan will therefore be crucial for the project success. The HSE regulations that are specific for the petroleum industry on the NCS include regulations that relate to qualification and use of new technology. The Facility regulation relates to design and outfitting of facilities and in section 9, qualification and use of new technology and new methods specified. It states that "*where the petroleum activities entail use of new technology or new methods, criteria shall be drawn up for development, testing and use so that the requirements for health, safety and the environment are fulfilled. The criteria shall be representative for the relevant conditions of use, and the technology or methods shall be adopted to already accepted solutions. The qualification or testing shall demonstrate that applicable requirements can be fulfilled using the relevant new technology or method*" (PTIL 2014). The regulation further refers to the Management regulation section 21 for follow-up, where it states "*This follow-up shall contribute to identify technical, operational or organizational weaknesses, failures and deficiencies*" (PTIL 2014). Section 9 in the Facility regulation also refers to the DNV RP-A203 as a qualification procedure that can be used to fulfill the requirements regarding methods for qualification of new technology. NORSOK D-010 is the standard for well integrity in drilling and well operations, chapter 15 in this standard contain well barrier element acceptance tables. The table contain a description of the element, its function, design, construction and selection, initial test and verification, use, monitoring, common well barriers. The table also refers to relevant international standards and NORSOK standards (NORSOK 2013).

### 4.7.1 DNV RP-A203 Qualification Procedure

The DNV RP-A203 can be used as a recommended practice in the technology qualification process, where the motivation for technology qualification is to manage the risks that are involved by implementing new technology and methods in an operation. Conventional concepts with well-known and proven technology is often preferred, even if the new technology can result in significant operational improvements or cost-savings. By performing a qualification process, the developers can provide evidence to ensure that the technology will function within specified operational limits and thereby lowers the implementation risk for its developers, manufacturers, vendors, operators and end-users. This recommended practice is intended to be used when the qualification process to show compliance is not obvious or covered by existing validated requirements, and where the risk of failure pose a risk to life, property, the environment or presents a financial risk (DNV 2013).

#### 4.7.1.1 Technology Qualification Program and Process

The objective in the qualification process is to use a systematic approach to ensure that the functional specification and associated failure mechanisms are relevant and complete in order to ensure that the technology functions reliable within the operational criteria. Generally, a new technology is developed in several steps from concept to eventually a finished product, on this path the technology is evaluated based on development milestones. In this process one gain more knowledge, experience and the probability of failure decrease along with the qualification process. The failure probability will increase if a modification is done during the process, until it decreases to a final remaining failure probability. It is now possible to conclude the qualification process if requirements for success are fulfilled. Figure 21 shows this behavior.

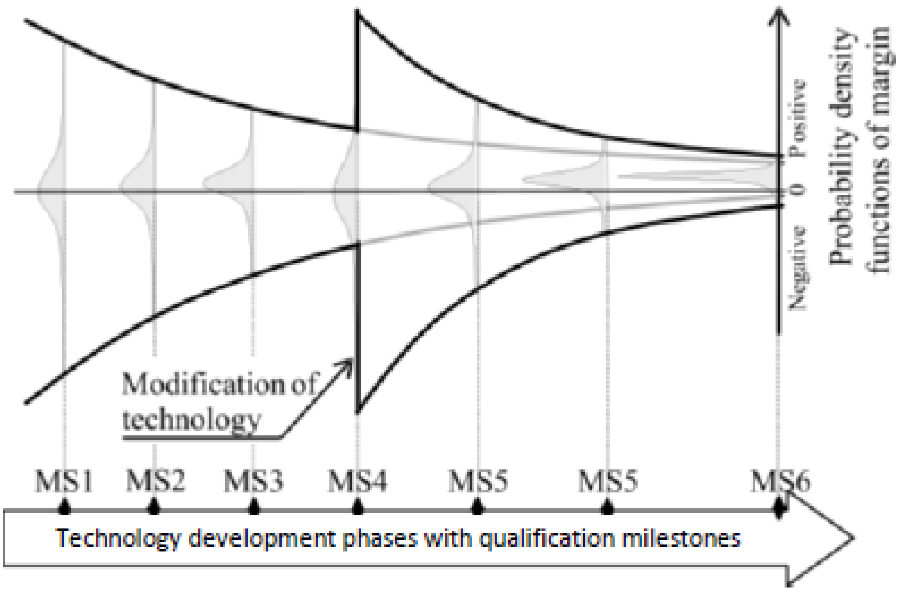



**Figure 21. Qualification process with milestones (DNV 2013)**

The qualification process is sectioned in phases based on milestones that shall be achieved and each phase have a qualification program to support the management of the process. The program includes milestones, which is a strategy for how the technology should be develop from its existing state to its goal. Decision gates should be linked to the success of milestones if possible, in order to decide if the course of development should be accepted or rejected. For enhancing products that is based on proven technology the qualification, strategy should include a solution to revert this fallback technology. For new and un-proven technology like the HOP concept, there exists no fallback solution and the success of the feasibility concept is dependent on a successful qualification program outcome. Technologies like this must satisfy the technology qualification basis or else a decision to implement it as it is, alter it or reject it, must be made. A qualification plan with different phases and process is shown in Figure 22. The program should be updated during after each phase to reflect the technology status (DNV 2013).

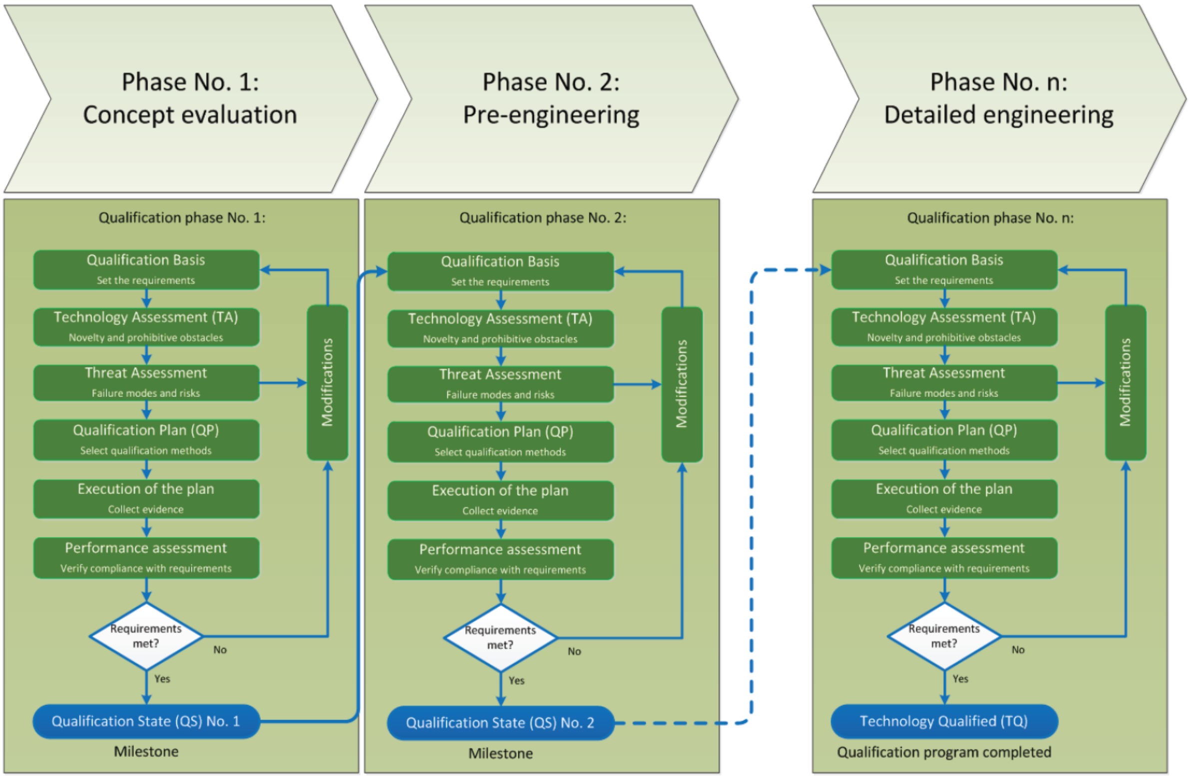



Figure 22. Technology qualification program, phases and process (DNV 2013)

The main steps in the process is visualized within each phase in Figure 22. Each step in the process shall be documented and the level of documentation have a tendency to increase as the qualification process progress. The advantage of documenting each step is that the conclusion becomes traceable. The steps in the process will be elaborated in the following.

The technology qualification basis identifies the specific functions, intended use and the environment of intended use, acceptance criteria and performance expectations to the technology and qualification targets. This is done to provide a common set of criteria that is used to assess all qualification activities and decisions.  A description of the technology and performance is necessary in order to create the qualification basis. The description of the technology shall include all relevant documents, drawings and calculations to define the technology function, limitations and relevant interfaces. This specification is used to identify the critical parameters. The technology performance shall be quantitative and complete, in order to express the existing qualification state and remaining milestones to technology qualification. The remaining milestones is expressed quantitatively in order to be measurable (DNV 2013).

The technology assessment use the qualification basis as input to determine which of the elements that require technology qualification and identify the key challenges and uncertainties. It is important in the technology assessment to identify if the concept is totally dependent of new technology or not. The technology composition is analyzed in order to fully understand the novel elements of the technology and to make the communication between people involved in different disciplines easier. The different elements identified in the composition analysis are then categorized according to their degree of novelty to focus the effort on the elements with the highest associated uncertainty. The uncertainty is dependent on the novelty of the technology and the application area. In Table 11 the elements are categorized from 1 to 4 depending on the novelty and only knowledge and experience that is documented, traceable and accessible for the team can be used to reduce the level of novelty. Category 2-4 are novel elements that shall be taken to the next step in the technology qualification process.

| Application Area | Degree of Novelty | | |
|---|---|---|---|
| | Proven | Limited Field History | New or Unproven |
| Known | 1 | 2 | 3 |
| Limited Knowledge | 2 | 3 | 4 |
| New | 3 | 4 | 4 |

**Table 11. Technology categorization (DNV 2013)**

The degree of novelty indicates:

1. This is a proven technology with no new technical uncertainties
2. New technical uncertainties
3. New technical challenges
4. Demanding new technical challenges

The novelty assessment can be complimented with assessing the technology development stage by a technology readiness level (TRL) analysis (DNV 2013). The technology qualification can start in any point of the TRL scale depending on the maturity. As the qualification process progress, the maturity of the technology increase and supported by necessary documentation the technology can be assigned a higher TRL number. Table 12 shows the TRL level and associated development stage and hardware development. A system contain several components and the component with the lowest TRL number will define the system TRL level (B.S. Aadnøy 2014).

| TRL Level | Development Stage | Hardware Development |
|---|---|---|
| 0 | Unproven idea/proposal | Paper concept. No analysis or testing has been performed |
| 1 | Concept demonstrated | Basic functionality demonstrated by analysis, reference to features shared with existing technology or through testing on individual subcomponents/subsystems. Shall show that the technology is likely to meet specified objectives with additional testing |
| 2 | Concept validated | Concept design or novel features of design validated through model or small scale testing in laboratory environment. Shall show that the technology can meet specified acceptance criteria with additional testing. |
| 3 | New technology tested | Prototype built and functionality demonstrated through testing over a limited range of operating conditions. These tests can be done on a scaled version if scalable. |
| 4 | Technology qualified for first use | Full-scale prototype built and technology qualified through testing in intended environment, simulated or actual. The new hardware is now ready for first use. |
| 5 | Technology integration tested | Full-scale prototype built and integrated into intended operating system with full interface and functionality test. |
| 6 | Technology installed | Full-scale prototype built and integrated into intended operating system with full interface and functionality test program in intended environment. The technology has shown acceptable performance and reliability over a period of time. |
| 7 | Proven technology | Technology integrated into intended operating system. The technology has successfully operated with acceptable performance and reliability within the predefined criteria. |

**Table 12. TRL table (DNV 2013, B.S. Aadnøy 2014)**

Threat assessment is the step where relevant failure modes with underlying failure mechanisms are identified, and the associated risks are determined. The threat assessment use input from the qualification basis and the technology assessment step to generate a failure mode register as output form the process. The failure mode register shall contain all failure modes and their associated risks, and throughout the qualification process, the register shall be updated to keep track on changes, assumptions, category of novelty, risk category and a reference to the source of evidence in the threat assessment. The failure mode assessment shall assess the whole life cycle of the object of interest and identify all possible failure mode and underlying mechanisms. Some possible methods to preform failure mode assessment is Failure Mode, Effect and Criticality Analysis (FMECA), Hazard and Operability study (HAZOP) or Fault Tree Analysis (FTA). The identified failure modes are then rank according to their contribution to overall risk or failure mode risk. The risk of failure is determined by the consequence and probability of failure. This is often visualized using a risk matrix like Table 13. The failure modes that are categorized to have medium or high risk are considered to be critical, and shall be covered by the technology qualification plan (DNV 2013).

| | | Increasing Probability | | | | |
|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 |
| Increasing Consequence | 1 | L | L | L | M | M |
| | 2 | L | L | M | M | M |
| | 3 | L | M | M | M | H |
| | 4 | M | M | M | H | H |
| | 5 | M | M | M | H | H |

**Table 13. Risk Matrix, L=Low, M=Medium, H=High**

The Technology qualification plan is developed with input from previous steps to provide the evidence needed to manage the risks identified in the threat assessment. Here, the qualification method is specified as an activity that shall provide evidence to document compliance with the requirements listed in the qualification basis. All qualification activities shall be traceable to the failure mode register that is developed in the threat assessment (DNV 2013). A key challenge in the qualification plan is to derive a list over all activities and sub-activities needed to qualify the technology, and it is therefore advisable to use a multidiscipline team when the different activities are defined (B.S. Aadnøy 2014). Different activities can be based on using models, experiments and testing. Models can be used directly if there exists proven numerical or analytical models to simulate the failure mechanism in its intended environment, if the model is newly developed its validity needs to be proven through qualification activities. Experiments and tests are a planned part of the qualification and provide experimental evidence for the qualification process. The confidence of the results obtained in experiments and tests are ensured by an independent review (DNV 2013).

Execution of the technology qualification plan represents the main cost in the qualification process and can be very time consuming compared to the other steps. Here all activities are executed according to plan and data is collected to determine the performance margins for each failure mode. It is important that all activities are well planned and chosen to generate the necessary information regarding the failure mode to deliver maximum value for invested time and resources. Data collected in the execution shall be organized in such a way that it ensures traceability through all the steps in the qualification process. The value of this is that an independent review can trace how the threat was identified, how the threat is addressed in the process, evidence developed through activities and how the evidence meet the requirements laid down in the qualification basis. It also generate value for qualification of similar designs as some data may be reused (DNV 2013).

In the performance assessment, the objective is to assess the collected data to measure how the technology meets the requirements from the qualification basis and if the risk is reduced to an acceptable level. Further qualification activities and modification of the technology can be the result if the assessment concludes that some requirements are not met in the process. If this is not feasible, the technology qualification have failed (DNV 2013). The performance assessment shall document that the technology can be implemented safely. Any risks that cannot be reduced without testing the technology in field, shall be highlighted and communicated (B.S. Aadnøy 2014). The decision making is based on (DNV 2013):

- Documentation of compliance with requirements in the qualification basis
- A judgment whether or not the specified development stage is reached during the process
- The confidence that the decision makers have acquired through their better understanding of the novel technology

## 4.8 Application of Hole in One Producer

A concept like HOP can be used to access petroleum resources located out of reach for conventional technology and which are not sufficiently large to be realized with a subsea or platform development. Field developments can in the future become very different from what is seen today if the concept becomes a success. Fewer platforms and subsea installations are necessary to exploit the same reservoirs, much like what was seen when the first ERD wells were drilled. The introduction of ERD wells in the early 1990 has reduced the number installations necessary to develop fields and this advantage was used for the Statfjord Field, Wytch Farm and Sleipner West development (H. Blikra 1994, M.L. Payne 1994). Reservoirs that is located close to shore have been cost-effectively exploited after the introduction of ERD wells on both Wytch Farm and the Sakhalin Project (V.P.Gupta 2014), further advances in ERD with the introduction of HOP drilling can increase the envelope of accessible reservoirs from shore. As an example the possible reservoirs of the coast of Lofoten, Norway, could be developed with the HOP concept from an onshore drilling site (IRIS 2009).

### 4.8.1 Advantages with Hole in One Producer

The HOP concept introduces some advantages to the industry, which conventional drilling and other solutions cannot provide. Some reservoirs are located in environmentally sensitive areas where conventional drilling methods will not be applicable. This was one of the major reasons for the onshore development of Wytch Farm, where ERD wells provided a solution to access the reservoirs with a minimum environmental footprint (BP 2014). Using the HOP concept this envelop increase and more hydrocarbon resources in such areas can be environmentally friendly exploited. One of the major challenges met after drilling an ERD well is running of the completion string. The different challenges related to running of lower completion is often seen in context with poor hole cleaning which prematurely stops the completion string and a high friction factor in the well which prevents the string from reaching TD (J. Holand 2007, O. Høvring 2009). In the HOP concept the necessary lower completion is included in the drill string, so that the completion is placed in the same run as the well is drilled. Reelwell, which also uses a dual drill string only address the drilling and casing running phase and have simulated that it is possible to drill 15,800 m long wells (O. Vestavik 2013). The packer pairs in the HOP design can provide very good well control due to the close interval between each pair, this partially isolates the different sections and allow for pore pressure drilling. The HOP drill string is equipped with multiple sensors to provide information about for the drilling operation, string tension, pressure and temperature. The amount of information that is available is large and since the system use electrical cables and wired drill pipe, the transfer capacity is much larger than for mud pulse telemetry (B.Aas 2008).

### 4.8.2 Operational and Practical Challenges

Here the focus will be towards the use of the HOP concept in a drilling operation and handling of the equipment on the rig. The HOP concept shall in principle use a dual casing where the inner casing is eccentric in the outer and only welded in the low end. The outer casing is intended to have a very slim tool joint with a specially designed outer connection since the joints cannot be torqued up as conventional tubular. This result in three different challenges that needs to be address both individually and combined.

In conventional operations the drill pipes and some casing strings are deployed in the well using the elevator located under the top drive. The elevator clamps around the tubular and can hoist or lower the string since the tool joint is sufficiently large and strong to withstand this load. Another option for casing is to use a tool that stabs into the casing and locks in place, to allow hoisting or lowering. For the HOP case the stab in solution is not possible due to the design and the elevator solutions will depend on the drill string weight and the tool joint neck size. A solution for fishing the string if the string is parted should also be derived.

The dual string connection have two steering pins that is used to align the two tubular correctly before a connection. This imply that the tubular which is hanging above the one in the rotary table needs to be adjusted clock or counter-clockwise. This is possible to do if the hanging tubular is in the elevator, but such precise operation of the elevator can be difficult and contributes to longer time spent on connections. It may also be necessary for the driller to have help from a roughneck on the drill floor to align the two tubular perfectly, which implies that the roughneck will be in the "red zone" on drill floor.

The initial connection design use a manually operated connection that is screwed from one casing and over the other. The roughneck will therefore be in the "red zone" on drill floor to perform this work, this can also increase the overall time spent on connections.

The initial concept of HOP presented here indicates that the drill floor is moving towards less automation. This does not comply with the drilling regulation introduced in 1981 and extended in 1992 by the Norwegian Petroleum Directorate. This states that it is required with remotely controlled pipe handling equipment to do pipe racking, making up/breaking out, and suspension in the rotary table of drill pipe. This regulation resulted in a significantly reduction in injury incidents and have resulted in a positive impact on the health and working environment in drilling (K. Brønnick 1999).

The HOP concept is largely based on development of new technology and the use of existing methods in a new way, according to Table 11 the HOP concept will be categorized with a degree of novelty on 4. This is the highest categorization of novelty and is also the technology which have the highest associated uncertainties and that in many cases it will be very time consuming to qualify the technology. In operation, the concept use advanced technology to control the packer expansion cycles, which involve many different components which can have many different failure modes. The consequence of failure can be packers locked in inflated mode or not responding correctly to the signals, but even though failure of one packer pair is not critical, it represents an unwanted incident with a limited hazard potential and the packer pairs are part of the well control in the concept. In the technology qualification, this will be related to the risk matrix in Table 13. Good procedures for mitigation of failure needs to be developed together with contingency plans for potential incidents. There will often be a higher associated risk with using new technology that is unproven in the field and a likely scenario if failure of the HOP will depend on how far the well is drilled before failure and the cause of failure. If the well is drilled thorough sufficient amount of reservoir it can start producing, if this is possible due to the cause of failure. The other likely scenario will be to drop the HOP string and either sidetrack or permanent abandon the whole well. Variables the will affect this decision is economics, risk of similar failure and problems encountered in the abandoned wellbore.

Logging tools used in the BHA like MWD/LWD can contain radioactive sources for gamma-ray logging, density logging and/or neutron logging. If a radioactive source is used, than it shall be possible to retrieve it, as abandonment of a radioactive source shall not be planned (PTIL 2014).

In the production phase several challenges can be encountered among other insufficient hydrocarbon flow due to pressure drop and plugged sand screens. The HOP well will be very long and have a large frictional pressure drop in the string which lowers the differential pressure between reservoir and well. Intervention methods that are used during the production phase to perform maintenance, stimulation, etc. needs to be specified and concept evaluated.

### 4.8.3 Spinoff Application of Hole in One Producer Technology

The HOP concept is based on new technology and the use of existing technology and methods in a new way. This gives the project a high degree of innovation and allow the team to evaluate new ways of performing a task. Already identified spinoff application of the HOP is the use of the traction unit to deploy the lower completion in long wells where traditional technology have shortcomings (D. Gardner 2013). Another application of the traction units could be to pull casing or tubing during workover or to pull stuck objects in the well. The concept will involve developing a better way of handling tubular on the rig due to the complexity of the concept, which can be beneficial for the whole industry.

# 5 Comparing HOP and a Subsea Field Development

Comparison of the cost of a subsea well and a HOP well be the focus in this chapter. The two different cases is elaborated with their associated costs. In both cases it is assumed that the wells are drilled to exploit a reservoir that have its center approximately 20 km away from an existing facility. The HOP will achieve a better reservoir exposure as it horizontally enters the reservoir from the edge towards the center. The difference in potential production is not considered in this case, only an estimate of development cost is evaluated. The potential for the HOP system after qualification depends on the cost of developing with HOP wells and the risk associated with using HOP, compared to a conventional development. A conventional development can be subsea development with subsurface pipelines to an existing facility offshore or onshore. For the HOP case the well cost will include the cost of drilling a very long well first that are used as the initial start for the HOP well. The HOP concept is also associated with much risk as it is a new method to drill and complete a well and the cost of an eventual failure and subsequently sidetrack should be included.

## 5.1 Subsea Well

A subsea solution to develop field have become more regular on the NCS both for larger and smaller field. The Ormen Lange field is a subsea development with pipelines to shore (F. Gustavsson 2003), and Statoil subsea technology on to exploit marginal fields with a standardized fast-track subsea solution. The advantage with using standardized equipment in the fast-track development is a cost-saving of 20% and a reduction in time from discovery to development (Statoil 2014). According an expert group appointed by the Oil and Energy department in Norway the average cost of an development well drilled from a moveable rig on the NCS was 600 MNOK in 2010 (Eivind Reiten 2012). This well cost is an average for all the development wells and not only for a subsea well. Table 14 shows the separate cost elements in a simple subsea development and the cost of a subsea solution with 20 km pipeline to an existing facility.

| Element | Cost | Subsea solution cost |
|---|---|---|
| Subsea template, work on seabed, etc. | 40 MNOK | 40 MNOK |
| Well | 600 MNOK | 600 MNOK |
| Pipeline | 18 MNOK/km | 18*20 = 360 MNOK |
| Total cost | | 1000 MNOK |

**Table 14. Cost of Subsea elements (Eivind Reiten 2012, B.S. Aadnøy 2014)**

The example case used in Table 14 include drilling a production well 20 km away from an existing facility where the subsea solution is connected. A subsea development like this is regular operation on the NCS and the risk of surpassing the cost estimate is low.

## 5.2 HOP Well

The HOP concept is as mentioned associated with more risk due to its novelty and will therefore include the cost of eventual sidetracking the primary wellbore in this example. First, the well is drilled conventional until the 9-5/8” casing is cemented in place. With the initial HOP concept this casing needs to be placed at 10,000m MD to allow for the HOP to reach the 20 km mark. Then is the HOP drill string deployed in the well and HOP drilling starts. In conventional drilling on the NCS one assume that it is drilled 70 meters per day and this include all parameters (B.S. Aadnøy 2014). This means that drilling and completing a 20 km long well will take approximately 286 days. It is possible to argue that the HOP concept will drill more meters per day as it have the completion equipment in the drill sting and would in that way save several days compared to the conventional method. However, the HOP well will have more reservoir exposure and the drilling rate in the reservoir section is lower, approximately 20-30 meters per day (B.S. Aadnøy 2014). The assumption of 70 meters per day is therefore used for this example. The daily cost is related to rig rent, logging and directional support and other services. The average rig rent for jack-ups on the NCS is 2.05 MNOK (Offshore.no 2014), but the total daily cost during drilling operations are approximately in the area of 4-5 MNOK (Kjell Kåre Fjelde 2014).

| Element | Cost |
|---|---:|
| HOP drill string | 800 MNOK |
| Daily cost | 4 MNOK |

**Table 15. Cost of elements in HOP well**

Table 15 shows the costs related to the elements in a HOP well. The HOP drill string is made for staying in hole after reaching target and it is only the drill pipe used to deploy the HOP string that is changed out with a production tubing after reaching target. The estimated cost of the string is based on a hypothetical cost assumption of completion equipment, traction units, dual sting and drill stem.

The scenario used in the example is that the 9-5/8” casing is drilled to 10 km, before the HOP string drills further to 15 km and a failure cause the well to be sidetracked. The well is plugged back and sidetracked from 14.5 km, it is assumed that the plugging takes two weeks. The sidetrack reach target successfully.

| Element | Calculation | Total cost |
|---|---|---:|
| Initial well 9-5/8” | (10,000/70)*4 | 571 MNOK |
| First HOP | 800 + (5,000/70)*4 | 1086 MNOK |
| Plug and abandonment | 14*4 | 56 MNOK |
| Sidetrack HOP | 800 + (5,500/70)*4 | 1114 MNOK |
| Total cost | | 2827 MNOK |

**Table 16. Cost of HOP well**

The cost estimate of a HOP well including a sidetrack is shown in Table 16. The estimate use a very optimistic assumption of the daily cost with only 4 MNOK. The HOP well is in the example almost three times the cost of a subsea solution.

# 6 Discussion

ERD wells have contributed to substantial cost benefits after the introduction to the industry in the mid 1980’s (R.C. Wilson 1986) and early 1990’s (H. Blikra 1994). Fields can now be developed based on a drainage radius in excess of 10 km in contrast to the Statfjord field development, which was based on a drainage radius of 3 km (A. Njaerheim 1992). The Sakhalin Project have proven that long ERD wells can be drilled without major challenges through a continuously improvement strategy. The project have brought the conventional drilling technology to an apparent limit where innovation and new methods may be necessary to extend the ERD envelope (R.W.James 2012, V.P.Gupta 2014).

A possible solution to extend the ERD envelope is the HOP concept, which is elaborated in the previous sections. This concept is intended to provide the opportunity to drill and complete wells that are in the excess of 16 km. The HOP is still in the conceptual stage and its function and reliability is therefore associated with much uncertainty. Challenges related to technology development, operation, intervention and production needs to be addressed together as one system, in addition to separate systems. Due to its degree of novelty it will be a long way from concept to qualified technology as indicated in section 4.7.1. As of today the only component that have been laboratory tested in the conceptual phase is the packer (D. Gardner 2013), which is only one of several critical components in the system.

The potential for the HOP system after qualification depends on the cost of developing with HOP wells and the risk associated with using HOP, compared to a conventional development. A conventional development can be subsea development with subsurface pipelines to an existing facility offshore or onshore. Based on the comparison in Chapter 5 the cost difference between a HOP well and a subsea well is very large and based on the economics the subsea solution would be preferred. The example is hypothetical and do not include the potential higher production that the HOP can achieve due to the higher reservoir exposure. However, it is more reasonable to think that the potential for the HOP is larger in cases where ERD technology like HOP may be the only viable option for developing an environmentally sensitive area that is not accessible with today’s conventional drilling technology.

The HOP is not the only concept that are showing potential for drilling wells in excess of 15 km. Reelwell have developed a method of drilling with a dual drill string and have through simulations shown that it is possible to drill wells in excess of 15.8 km (O. Vestavik 2013). One advantage for Reelweel is that they have already successfully full scale tested their main elements (O. Vestavik 2009) and in 2010 the system was deployed in a shale gas well in Canada. This demonstrated the implementation on a conventional rig and validated the concept in addition to provide more information for further development (M.A. Belarde 2011). The two methods are very different and the Reelwell method is developed more on known technology and is focused on drilling the well, while HOP is based on new technology and include the completion. As mentioned in section 4.8.1 one challenge in long wells is running the completion, and a possible solution can be to use the Reelwell method to drill the well and the HOP traction units to deploy the completion. This can be a possibility for the HOP concept to gain field experience with the traction unit while the rest of the concept is technology qualified and developed.

# 7 Conclusion

The use of ERD wells have increased the last two decades and the benefits of this technology were shown in the Wytch Farm and Statfjord development, where it resulted in a substantial cost saving. ERD can be used for increasing the recovery from a field by accessing the remote parts of the field in a cost efficient way. These long reach wells are limited by several factors as shown in Chapter 3, but there is ongoing research to reduce the impact from these factors to increase the ERD envelope. Some of the outcome from such research is the AST tool developed by Tomax, which can be used to reduce detrimental vibrations in the drill string, and the IDAs real-time system, which can optimize drilling and detect potential tight spots and poor hole cleaning.

The Sakhalin Project showed how continuous improvement of equipment, well design and drilling method results in some of the longest wells in the world, without experiencing any major challenges or incidents. The project team optimized among other the BHA and bit design to minimize drill string vibrations and bit wear to reduce the number of BHA and MWD failure, which required tripping out. Tripping out of hole to replace a failed component in the string in such long wells results in leaving the hole open for 6 additional days, which can result in severe hole problems.

The Hole in One Producer concept is an innovative ERD solution, which can extended the ERD envelope substantially. The concept is in conceptual phase and the success is totally dependent on successfully developing new technology and have several design challenges, such as the traction unit, control system and the dual casing. The HOP dual casing and connections needs to be designed for withstanding very high pressures and axial loads as indicated in Chapter 4. The concept is therefore still far from being technology qualified, as is indicated in the evaluation of the concept in this thesis.

The HOP drilling method will require new topside equipment on the drilling rig to deploy the string and new drilling procedures. Some potential challenges related to this, is identified to be elevator for deploying the string and the need of personnel in the drill floor “red zone” during connections.

The HOP is therefore associated with a high degree of uncertainties and the use of the concept will impose a large financial risk compared to a conventional solution. The cost comparison between a subsea well and a HOP well indicates that the large cost difference will make commercialization difficult. It is perhaps more likely that different spinoff applications of the concept technology can be commercialized and then especially the traction unit.

The advantage of the HOP concept is the potential of exploiting hydrocarbon resources that are in close vicinity of shoreline and in environmentally sensitive areas. In such areas, the HOP can be used to achieve a minimal environmental footprint.

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# Appendix A.

| Field | Well | Year | HD [m] | MD [m] | TVD [m] | HD/TVD |
|---|---|---|---|---|---|---|
| WF | F18 | 1988 | 3856 | 4450 | 1669 | 2,31 |
| WF | F19 | 1988 | 5001 | 5757 | 1672 | 2,99 |
| WF | F20 | 1993 | 4486 | 5300 | 1667 | 2,69 |
| WF | F21 | 1994 | 5420 | 6180 | 1627 | 3,33 |
| WF | M1 | 1994 | 5600 | 6393 | 1602 | 3,50 |
| WF | M2 | 1994 | 6760 | 7522 | 1571 | 4,30 |
| WF | M3 | 1995 | 6818 | 7450 | 1572 | 4,34 |
| WF | M5 | 1995 | 8035 | 8715 | 1591 | 5,05 |
| WF | M6 | 1996 | 6100 | 6876 | 1577 | 3,87 |
| WF | M11 | 1997 | 10000 | 10658 | 1585 | 6,31 |
| WF | M16 | 1999 | 10728 | 11287 | 1617 | 6,63 |
| Statfjord | C10 | 1990 | 5006 | 6200 | 2698 | 1,86 |
| Statfjord | C3 | 1990 | 6086 | 7250 | 2696 | 2,26 |
| Statfjord | C24 | 1992 | 5679 | 7137 | 2728 | 2,08 |
| Statfjord | C2 | 1992 | 7290 | 8761 | 2788 | 2,61 |
| Sakhalin | OP-8 | | 9206 | 9934 | 1794 | 5,13 |
| Sakhalin | OP-7 | | 8951 | 9662 | 1784 | 5,02 |
| Sakhalin | OP-6 | | 8902 | 9600 | 1768 | 5,04 |
| Sakhalin | OP-9 | | 10324 | 11036 | 1796 | 5,75 |
| Sakhalin | OP-4 | | 9217 | 9994 | 1769 | 5,21 |
| Sakhalin | OP-3 | | 8257 | 8965 | 1803 | 4,58 |
| Sakhalin | OP-10 | | 10527 | 11238 | 1829 | 5,76 |
| Sakhalin | OP-11 | 2011 | 11479 | 12345 | 1784 | 6,43 |
| Sakhalin | OP-2 | | 7000 | 7726 | 1768 | 3,96 |
| Sakhalin | Z-4 | | 9247 | 10183 | 2600 | 3,56 |
| Sakhalin | ZG-2 | | 9535 | 10523 | 2600 | 3,67 |
| Sakhalin | ZG-1 | | 9510 | 10537 | 2600 | 3,66 |
| Sakhalin | Z-1 | | 9773 | 10995 | 2600 | 3,76 |
| Sakhalin | Z-2 | | 10088 | 11070 | 2600 | 3,88 |
| Sakhalin | Z-11 | 2007 | 10317 | 11282 | 2600 | 3,97 |
| Sakhalin | Z-12 | 2008 | 10536 | 11680 | 2600 | 4,05 |
| Sakhalin | Z-44 | 2012 | 11371 | 12376 | 2400 | 4,74 |
| Sakhalin | Z-45 | 2012 | 10251 | 11277 | 2600 | 3,94 |
| Sakhalin | ZGI-3 | 2012 | 11367 | 12325 | 2400 | 4,74 |
| Sakhalin | Z-43 | 2013 | 11588 | 12450 | 2400 | 4,83 |
| Sakhalin | Z-42 | 2013 | 11739 | 12700 | 2400 | 4,89 |
| Sakhalin | ZGI-41 | 2013 | 11200 | 12020 | 2400 | 4,67 |
| Al-Shaheen | BD-04A | 2008 | 10903 | 12290 | 1061 | 10,28 |

Table 17. ERD wells

# Appendix B

| Industry unit | Conversion factor | Metric unit |
|---|---|---|
| Feet | 0.3048 | m |
| Inch | 0.0254 | M |
| Lbm/ft$^3$ | 16.01846 | Kg/m$^3$ |
| GPM | 0.06309 | L/s |
| Lbf | 4.448222 | N |
| Lbm | 0.4535924 | Kg |
| cP | 0.001 | Pa*s |
| Cubic feet | 0.02831685 | m$^3$ |
| bbl | 0.1589873 | m$^3$ |
| Lbf/in$^2$ | 6.894757 | kPa |
| ft/hr | 0.3048 | m/hr |
| Lbm/ft | 1.48816 | Kg/m |

**Table 18. Conversion factors**

# Appendix C

Calculation of torque and drag in Chapter 3.2.1. Equations used for well profile is shown here, while equations for torque and drag is presented in the thesis.

$$Radius = \frac{30*360}{2*\pi*\emptyset} \tag{A.1}$$

Where the build-up rate is $\emptyset/30$m.

The measured length of the build-up section

$$Arc\ length = 30 * \frac{\alpha}{\emptyset} \tag{A.2}$$

Where α is the inclination of the sail section.

| Element | Value |
|---|---|
| DLS | 2.0/30m |
| Radius | 859 m |
| e | 1.3129 |
| -e | 0.7616 |
| Friction | 0.20 |
| Mud weight | 1.46 sg |
| Buoyancy | 0.814 |
| Buoyant Drill pipe weight case 1 and 2 | 0.2717 N/m |
| Buoyant Drill pipe weight case 3 | 0.2612 N/m |
| Buoyant BHA weight | 1.7338 N/m |
| Sail section inclination | 78° |

**Table 19. Elements in calculation**

| Case 1 | | |
|---|---|---|
| Position | TVD [m] | MD [m] |
| KOP | 600 | 600 |
| Build | 841 | 1170 |
| Sail | 1500 | 7215 |
| Sail BHA | 21 | 100 |
| Total | 2962 | 9085 |
| Case 2 | | |
| Position | TVD [m] | MD [m] |
| KOP | 4800 | 4800 |
| Build | 841 | 1170 |
| Sail | 650 | 3126 |
| Sail BHA | 21 | 100 |
| Total | 6312 | 9196 |

**Table 20. Well profile for Case 1 and 2**

| Case 1 | | | | |
|---|---|---|---|---|
| Position | Static [kN] | Hoist [kN] | Lowering [kN] | Torque [kNm] |
| Top BHA | 36 | 70 | 2 | 3 |
| Bottom build | 444 | 861 | 25 | 37 |
| Top build | 672 | 1359 | 248 | 48 |
| Top Well | 835 | 1522 | 411 | 48 |
| Case 2 | | | | |
| Position | Static [kN] | Hoist [kN] | Lowering [kN] | Torque [kNm] |
| Top BHA | 36 | 70 | 2 | 3 |
| Bottom build | 213 | 379 | 13 | 18 |
| Top build | 441 | 726 | 238 | 23 |
| Top Well | 1745 | 2030 | 1542 | 23 |
| Case 3 | | | | |
| Position | Static [kN] | Hoist [kN] | Lowering [kN] | Torque [kNm] |
| Top BHA | 36 | 70 | 2 | 3 |
| Bottom build | 428 | 830 | 25 | 31 |
| Top build | 647 | 1310 | 239 | 40 |
| Top Well | 804 | 1467 | 396 | 40 |

**Table 21. Torque and drag result**