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Master Thesis
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The Impact of Wired Drill Pipe on the Martin Linge Field

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Abstract

This thesis studies the impact of wired drill pipe telemetry on the Martin Linge field. In addition, the utilization of along string measurements will be analysed and a verification will be made on both how far the technology has come, and the way forward.

The reliability trends for the wired drill pipe telemetry system on Martin Linge are positive. The reliability rates achieved, currently averaging 91% uptime, might be one of the highest on the Norwegian Continental Shelf (NCS) so far. Uptime is a very important aspect of the wired drill pipe telemetry system, and it is important to put a focus on how to increase it. Having a third party responsible for the uptime has introduced a whole new incentive for increasing, and maintaining, stable uptime. Early start-up of the utilization of wired drill pipe telemetry has familiarized everyone with the equipment and handling of the tools, and has contributed to the network uptime gradually increasing.

Several examples of how to use the along string measurement pressure sensors will be presented, with respect to pack-off detection, hole cleaning, lost circulation and leak off testing. These can be used as means of analysing downhole data in real-time and used as a basis for software development.

In the end, high speed transfer of data between downhole tools and surface are reducing telemetry time and saving rig time. Currently, a reduction in telemetry time of 5.87 [hours/1000m drilled] has been achieved. Thus, a lot of cost has been saved by decreasing time spent on downhole communication.

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Abbreviations

ADT Applied Drilling Technology

ASM Along String Measurement

BHA Bottom Hole Assembly

BPS Bits Per Second

CTFV Critical Transport Fluid Velocity

ECD Equivalent Circulating Density

FIT Formation Integrity Test

FS Full Scale

GOR Gas Oil Ratio

IBOP Inner Blow Out Preventer

ID Inner Diameter

LCM Lost Circulation Material

LOT Leak Off Test

LWD Logging While Drilling

MD Measured Depth

MPD Managed Pressure Drilling

MTBF Mean Time Before Failure

MTV Minimum Transport Velocity

MWD Measurement While Drilling

NCS Norwegian Continental Shelf

NOV National Oilwell Varco

NPT Non-Productive Time

OD Outer Diameter

POOH Pulling Out Of Hole

PWD Pressure While Drilling

PWRI Produced Water Re-Injector

ROP Rate of Penetration

RPM Rotations Per Minute

RT Rotary Table

TDS Top Drive Swivel

TI Transport Index

TVD True Vertical Depth

WDP Wired Drill Pipe

WDPT Wiret Drill Pipe Telemetry

WITSML Wellsite Information Standard Markup Language

1 Introduction

Presently, the oil and gas industry is increasingly facing challenges to develop the reservoirs found. Most of the easy wells have been drilled and completed. Left are the more challenging fields. The challenges could be anything from deep-water drilling, depleted reservoirs, gas-hydrate formations to extended reach drilling. New technologies enables more efficient drilling, better understanding of the downhole environments and provides a method for drilling tough wells with a higher success rate.

Wired drill pipe telemetry (WDPT) is such a new technology. It can help reduce the non-productive time (NPT), optimize borehole stability and impact the productivity through more precise geosteering into the reservoir.

The technology was commercialized in 2005, but has been sparsely used up until a few years back. Experience has shown that it is not easy for new technologies to gain market share in the petroleum industry. One reason for this is the large investment costs associated with drilling and developing fields. If anything goes wrong in the drilling process millions of dollars could be lost.

WDPT has been used on several fields in recent years, both on the Norwegian Continental Shelf (NCS) and at other locations. They therefore serve as a comparison baseline in terms of discussing reliability and other technological aspects.

1.1 Thesis Objective

The main objective of this thesis is to verify whether or not the wired drill pipe telemetry will be the new standard in drill pipe technology, and how it can be an enabler for integration of drilling technology and practices. This verification is done based on the Martin Linge field case. Important aspects that will be touched upon are cost, reliability and advantages of the WDPT. In addition, a special emphasis will be put on how to use the along string pressure measurements to improve borehole stability, hole cleaning and other downhole challenges.

This thesis is written in cooperation with Total E&P Norge, currently using wired drill pipe telemetry on their new development, Martin Linge. Drilling with wired drill pipe started in September 2014, so at the end of this thesis, the wired drill pipe telemetry had been used for approximately ten months.

Data interpretation of downhole pressures and other parameters are done through NOV's visualisation tool, WellData. This shows historical measurements, but are the same as can be measured real-time in Baker Hughes' measurement tool for Martin Linge, WellLink. Thus, the data is analysed with respect to the fact that they can be seen in real-time.

Information about the wired drill pipe, operational challenges and other related aspects and subjects, are based on the daily drilling reports, literature studies and conversations with service companies NOV IntelliServ, NOV Drilling Dynamic Solutions and Baker Hughes. In addition, conversations with other operating companies that have previously used wired drill pipe telemetry, have provided a greater insight into the development, and previous and present experiences with WDPT on the Norwegian Continental Shelf.

1.2 Martin Linge

The Martin Linge field is located on the Norwegian Continental Shelf in the central North Sea, near the delimitation line to the UK Continental Shelf. The production licenses are PL040, blocks 29/9 and 30/7 and PL043, blocks 29/6 and 30/4. The field contains both faulted and segmented gas accumulations in the mid-Jurassic Brent Group as well as a shallower oil reservoir in the Frigg formation. The oil reservoir was discovered in 1975 and the gas discovery followed in 1979, but due to the field complexity it has not been developed until now. Drilling started at the end of August, 2014.

Norsk Hydro was originally operator on the PL040 license and drilled eleven wells from 1975 to 2000. At this time Total took over the license. BP originally had the PL043 license and drilled three wells before Total took over as operator. In 2005 the PL040 and PL043 licenses was utilized with Total as operator. An appraisal well was drilled in 2009 and an extended well test was performed. This test proved the field to be economical and field development plans were initiated.

Currently, the license ownership is shared among three companies, shown in table 1.1.

Table 1.1: License owners in the Martin Linge field

Company	Share	Role
Total E&P Norway AS	51%	Operator
Petoro AS	30%	Partner
Statoil ASA	19%	Partner

The discoveries in the Martin Linge Brent area include four separate gas condensate accumulations; Martin Linge East, Martin Linge Central, Martin Linge West and Martin Linge South. All of which have different depths, pressures and fluid properties. Additional prospects include Gunn N, Gunn S, Herja and Hervor.

The Martin Linge Brent gas condensate and Frigg oil will be a combined development. Martin Linge Brent will be produced by natural depletion, while gas lift will be used for Frigg oil production as a mean of artificial lift due to low reservoir pressure, high viscosity and low gas-oil ratio (GOR). No pressure support is required for the Frigg oil due to a strong aquifer. There is no communication between the gas / condensate reservoirs in the Brent formation and the Frigg oil formation.

The approved Martin Linge field development consists of eleven wells; four oil wells, six gas wells and one produced water re-injector (PWRI) well. Six wells are planned to be pre-drilled through the jacket prior to platform installation and the remaining will be drilled simultaneously with field production. The platform has twenty-one well slots in total, allowing for another ten prospect wells. These prospects have been identified and have a planned well trajectory assigned.

The pipe is delivered by GrantPideco and the wiring done post-fabrication by IntelliServe, which is a joint venture between NOV (55%) and Schlumberger (45%). Along string measurements (ASM's) are delivered by NOV Dynamic Drilling Solutions and measurement while drilling- (MWD) and logging while drilling (LWD) services are provided by Baker Hughes.

2 Mud Pulse

This chapter will be used to give an overview of the type of telemetry that is mostly used on the Norwegian continental shelf, mud pulse telemetry. Other possible telemetry systems are electromagnetic telemetry and acoustic telemetry, but as they are used only in special cases, they will not be touched upon in this thesis.

Drilling is a complicated technological process with many uncertainties. Thus, it is very important to get as much information as possible of the downhole conditions, preferably in real-time. When data is received and analysed while drilling, it is possible to make adjustments so that the well can be drilled in a safe manner and the drilling parameters optimized, resutling in a higher quality borehole. We distinguish between two types of measurements; logging while drilling and measurements while drilling. LWD measures petrophysical data like gamma rays, resistivity, density and acoustic velocity to get a better understanding of the subsurface. MWD takes directional surveys by measuring the azimuth, hole deviation and also measures drilling mechanics data like weight on bit (WOB), torque, vibration, temperature and pressures.

A fraction of this data is transmitted in real-time while drilling, while the rest of it is stored in memory. [1],[2]

2.1 Mud Pulse Telemetry

Mud pulse telemetry (MPT) is a method to send signals from the bottom hole assembly (BHA) to surface by using the mud column. As in any telemetry system, there needs to be a transmitter and a receiver. In MPT, the transmitter and receiver technologies are often different if information is being uplinked or downlinked. In uplinking, the transmitter is a part of the MWD tool package in the BHA, generating pressure fluctuations in the mud column. This tool is commonly referred to as the mud pulser, or simply the pulser. The pulses are transmitted inside the drill pipe in binary codes. The surface receiver system consists of sensors that measure the pressure fluctuations and signal processing modules that interpret these signals, commonly known as decoding.

Downlinking is achieved by either periodically varying the flow rate through the pulser or by periodically varying the rotation-rate of the drill string according to a timed sequence. Within the BHA, the electronics and sensors in the MWD tool responds to changes in either the flow or pressure. [3]

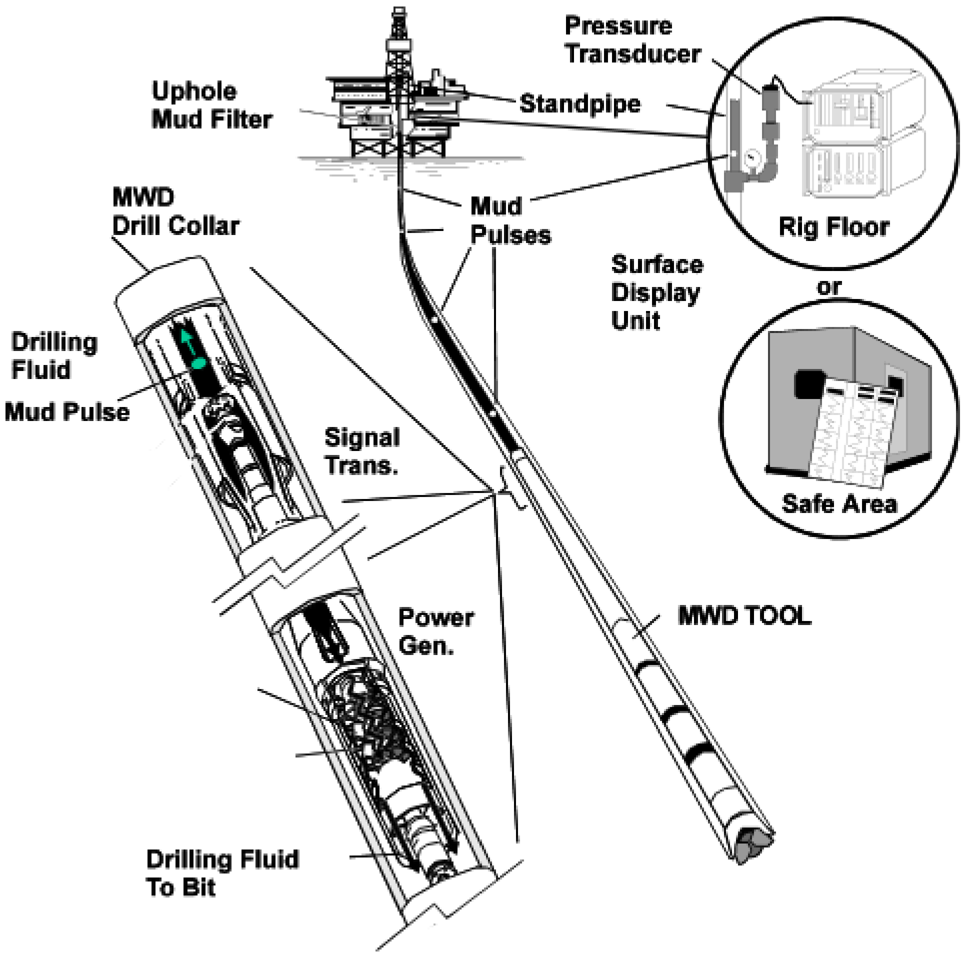


Figure 2.1: Network topology for a mud pulse telemetry system [3]

There are several different types of pulsers available, that are classified by the type of signals that they produce; discrete pulses or continuous wave signals. Discrete pulses can be either negative or positive. Rotary valve pulsers can generate only continuous wave signals while the shear-valve pulser can generate both discrete- and continuous wave signals. All mud pulsers operate independently, meaning there is no direct electrical or mechanical connection between the downhole environment and the surface.

There are three varieties of the mud pulse telemetry systems:

1. **Positive Pulse**: is created by momentarily restricting the mud flow through the downhole tool which results in an increase of pressure inside the drill pipe that propagates at the speed of sound to the surface, where they are sensed by a pressure transducer, measured and processed. The most common type of positive pulser involves two different designs. The first one uses the pressure of the mud to assist opening the valve, in other terms a hydraulically assisted valve. It is capable of delivering data rates up to 12 bits per second (Bps). The second type is fully isolated from the drilling fluid and consequently requires more power to open the valve. The advantage of the second type is that it is less prone to plugging by solids or lost circulation material (LCM), which makes it more reliable. However, the second type might not be as fast as the first type.

2. **Negative Pulse**: is created by momentarily shifting the flow of mud from inside the drill pipe directly to the annulus. This is usually achieved by a rotating valve. By bypassing the drill bit jets, a pressure drop is created and propagated to the surface. This pulser does not require the same amount of power as a fully enclosed "positive pulser", which makes it more power efficient and capable of delivering higher data-rates. The shearing action of the valve also makes it less prone to plugging.

3. **Continuous wave**: Pulsers of the rotary- or shear design can generate continuous wave signals at a given frequency of the signal or, its relative

phase. These types of pulsers consists of two slotted disks placed on top of each other perpendicular to the mud flow. One of the disks is stationary, the stator, and the other is free to rotate, the rotor. The speed of the rotor controls the frequency of the continuous pressure wave generated in the mud. If the rotor oscillates so that the aperture of the two disks is controlled, then the valve is termed a shear valve. Generally, rotary valves can generate only continuous-wave signals, while shear valves are very versatile and can generate both discrete and continuous wave signals. [3]

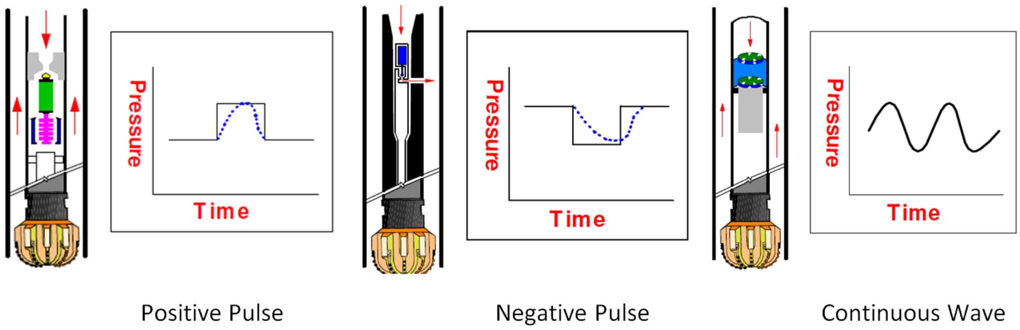


Figure 2.2: Positive, negative and continuous wave pulser signals [3]

To utilize the mud pulse system, some important pieces of equipment needs to be in place. In positive and negative pulses a mud pulse valve, often called a pulser, is needed. The pulser is located above the BHA and sends signals from the tools in binary codes. The codes are propagated through the fluid in pressure drops or increases. A pressure transducer in the standpipe decodes the pulses and the data gets stored.

For continuous waves, the pulser is exchanged with a stator and rotor. When the rotor turns it creates a sinusoidal signal by varying the speed of rotation.

When the rotor is aligned with the stator the mud can pass through, but when they are unaligned the passage gets blocked. [4]

Some of the challenges with conventional downhole communication lies in the following:

- **Insufficient downhole data during subsurface operations**
  The typical mud pulse transmissions are limited with respect to data transferring, usually sending only a dozen bps. In addition, the signal quickly degrades at greater depths encountered in deep water drilling and extended reach drilling. More data can be downloaded from the memory base of the logging equipment at surface, but are not available real time.
- **Limited drilling process data is only acquired near the bit**
  In MPT, data is only collected in the BHA and not along the string. Not having any measurements along the string makes it hard for wellsite personnel to know why the well is behaving as it does, for example in a situation where low weight on bit is being seen.
- **Inadequate receiver-transmitter arrangement**
  Commanding or diagnosing tools relies on applying pressure fluctuations through the mud column from surface, taking minutes to propagate to the downhole tools. In addition, the tools have to be pre-programmed to send the data of interest. This means that sometimes it is impossible to make the tools transmit the wanted data. [5],[6]

3 Wired Drill Pipe

High speed telemetry drill pipe, better known as wired drill pipe, is a technology that allows for faster telemetry rates of downhole data. The data transmissions are currently at 57,000 bps, which is more than a thousand times greater than fast mud pulse telemetry at 40 bps. It is based on the principle of electromagnetic induction, where inductive coils are placed in the box and pin end of a double shouldered connection. Physical contact between the coils is not required, as an electromagnetic field associated with the alternating current signal transmitted through the cable is responsible for transmitting data. As the alternating electromagnetic field from one coil induces an alternating current signal in the nearby coil, data is transmitted from one tubular to the next, as by the principle of induction.

An armoured coaxial cable, encapsulated inside a pressure sealed conduit, travels inside the drill pipe. It is connected to the coil and travels inside the body of the tool joint and enters the inside of the pipe itself. This can be seen in figure 3.3. The cable is under tension inside the pipe and is compatible with through-string operations and cementing. Once the pipe is made up, the data can be transmitted through the cable. [7]

Figure 3.1: Wired drill pipe version 1 coil

Since broadband telemetry works independently from the medium present, the networked drill string can transmit data regardless of the fluid environment. As a result the wired pipe can transmit data even with the absence of flow. This is one of the important features that sets it apart from the mud pulse telemetry system. It is now possible to look at downhole measurements, almost at all times. The only exception being when the pipe is disconnected from the top drive swivel.

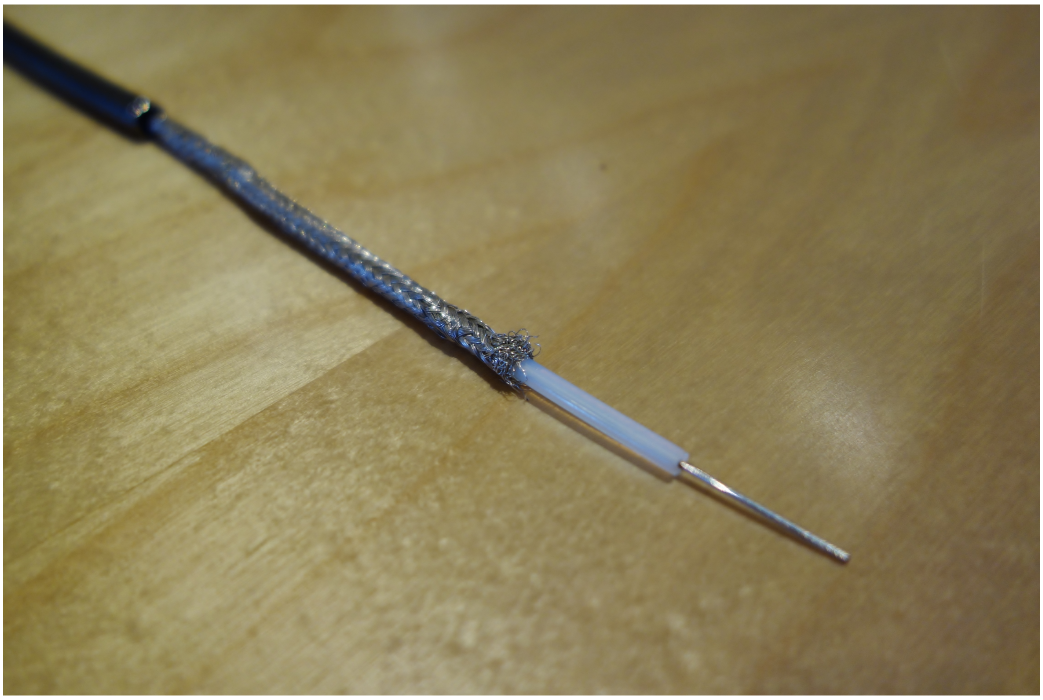


Figure 3.2: Wired drill pipe coaxial cable

The wired drill pipe consists of the following key items:

Top drive swivel A data swivel provides the interface between the rotating and stationary environments. It is installed directly above the inner blow out preventer (IBOP), enabling flow of data while the pipe is rotating. It consists of a telemetry-enabled sub, inductively coupled to a non-rotating member. Network traffic moves through the sub and into the swivel, which in turn is connected to the data acquisition system via surface cabling. Wired IBOP's and saver subs are provided by and purchased from IntelliServe. Via surface cabling the data will be fed into a surface system from IntelliServe that monitors network performances. Via wellsite information transfer standard markup language (WITSML) all other data is transferred into a data aggregation and/or visualization system from the MWD/LWD provider, Baker Hughes. An outline of the network topology is depicted in figure 3.5. The items inside the green box are considered part of the surface data acquisition system provided by IntelliServe. This system is small enough to be placed in the MWD/LWD cabin.

Telemetry pipe All string and surface components need to be wired to facilitate the transfer of data to surface, and all components require double shouldered connections. Examples of such components are float subs, crossovers, safety valves, dart subs and stabilizers, etc.

Figure 3.3: Wired pup joint model

Data Link Data boosters are embedded in tool joints at approximately every 500 m to increase the signal to noise ratio and ensure that no data is lost. The data booster consists of a 1.8 m sub with an electronics package, threaded on the bottom of specially manufactured drill pipe joints. The electronics package is being powered by a lithium battery. The 1.8 m sub is installed with a proprietary non-tapered connection onshore, is clearly marked and not intended for break-out on the rig.

Network rating of −40 °C to 150 °C is related to the temperature limitations for the batteries and electronics in the DataLinks and reflects the maximum tool temperature and not the formation or fluid temperature. Temperatures in the DataLinks are closely monitored and the elastomer seals are tested to 200 °C.

The DataLinks have a slightly reduced tool joint inner diameter (ID) to allow for the electronics and battery installation. The lithium battery has an operational lifetime of 60 to 90 days with a low power sleep mode when not in use. Remaining battery life is monitored via the IntelliServe software to plan the change of battery package onshore.

The data boosters can be fitted with pressure and temperature sensors to acquire along string measurements (ASM's). These are referred to as MeasurementLinks. Currently these MeasurementLinks only include temperature and pressure measurements, but the next generation will probably also include torsional, axial and lateral vibrations, and RPM sensors. Service companies are currently also looking into the possibility of adding different types of sensors.

Interface sub Communication between the wired drill pipe and the BHA is achieved by using an interface sub to provide bi-directional communication. These subs are provided by all major MWD/LWD service companies. Any string component run above the interface sub, as part of the drill string, needs to be wired. [8]

Surface network controller Creates and manages the drill string data network from surface. It distributes the data collected from downhole tools to their respective data-acquisition systems and provides visualization and diagnostics of the drill string network health. The network controller can provide:

- Simple visualisation of network status
- Activation and recordings of routine network tests
- Smart diagnostic engine to identify failure modes and provide recommended actions
- Downhole data through ethernet/serial
- Status of battery life and signal strength between all DataLinks [7]

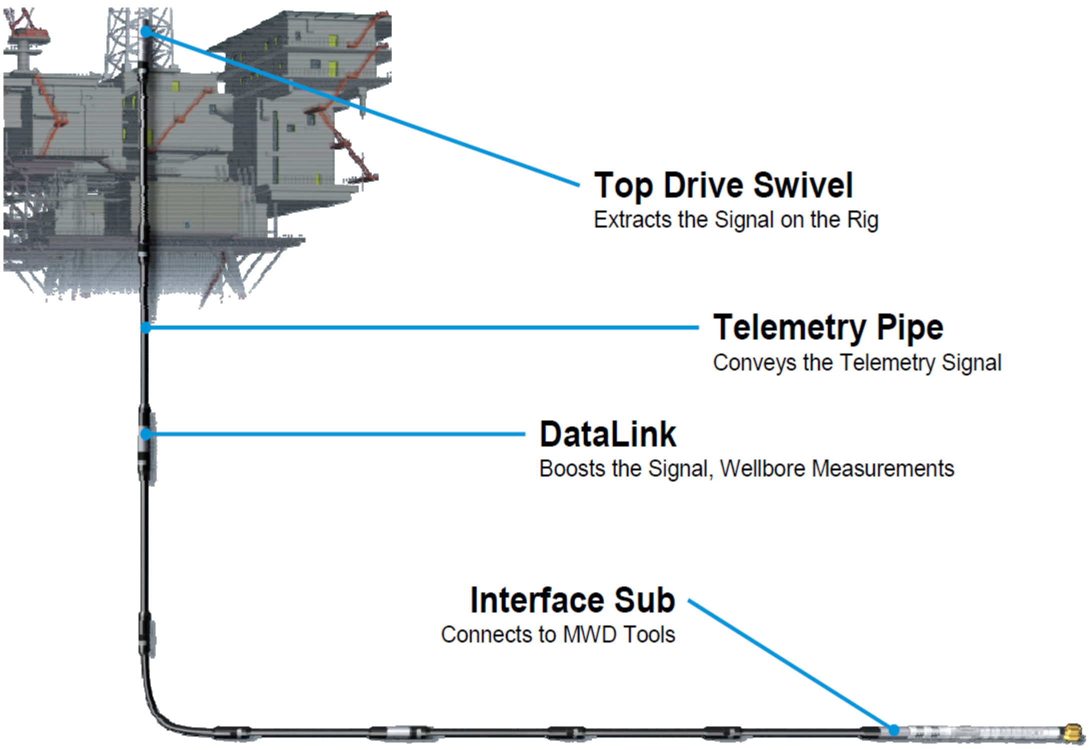


Figure 3.4: Key items for wired drill pipe telemetry

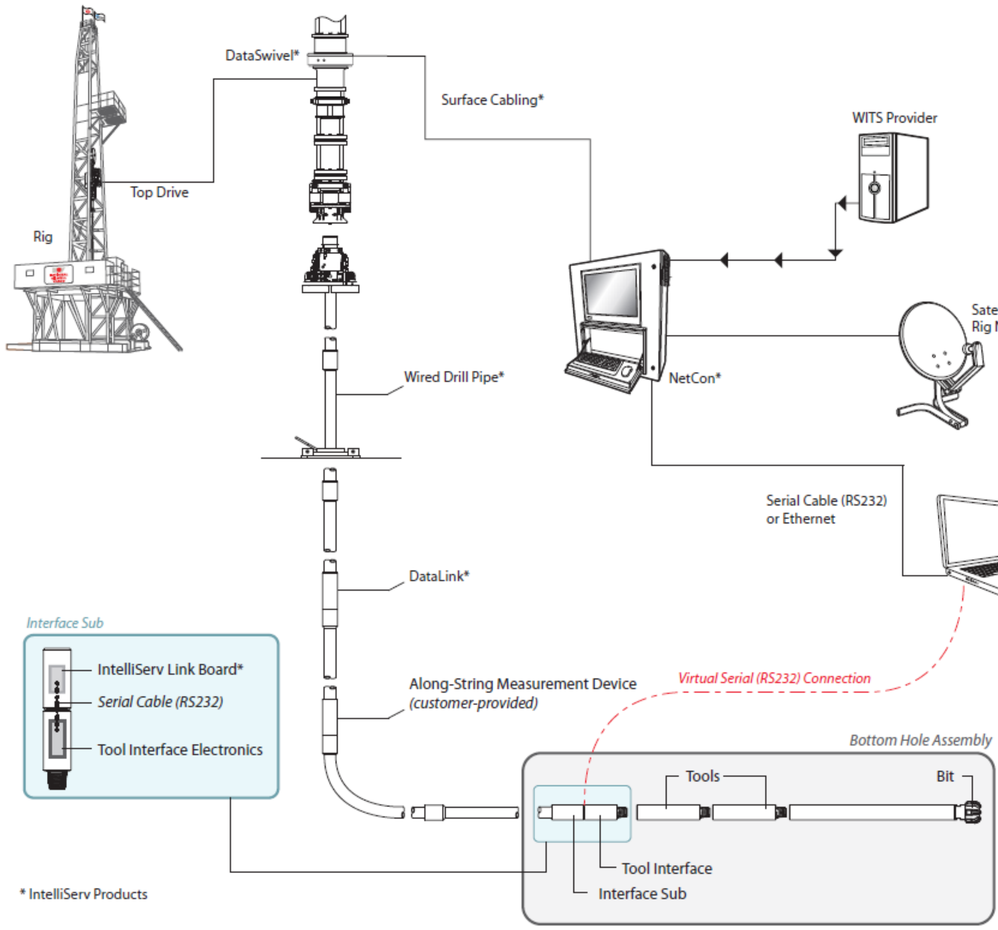


Figure 3.5: The wired drill pipe network topology outline

3.1 Advantages of Wired Drill Pipe Telemetry

This section will highlight some of Total's reasons for choosing wired drill pipe on the Martin Linge field, with short comments on how the pipe is actually performing with respect to the expectations. The different benefits were considered with respect to cost savings, reducing NPT and optimizing the quality of the wellbore.

When considering wired drill pipe telemetry, the scope of the field development and the technical difficulties of drilling were a very important aspect. The field has challenges with a possible loss zone with subhydrostatic pressures in the Frigg formation. This means that the pressure gradient in that formation is below the pressure gradient for seawater, which is normally used as pore pressure. In addition, the Hordaland "green clay" formation is a reactive shale section, meaning that high mud weight is required to keep the formation to creep and close around the drill string. However, the latter was not an initial reason too implement wired drill pipe. Other challenges include complicated well trajectories and long horizontal sections. In addition, Martin Linge is a relatively big development with a lot of future wells being drilled. Wired drill pipe requires a large initial capital investment, but there are cost savings to be made per well on telemetry time. Hence, the more wells are drilled, the more time is being saved. Time can be saved by using wired drill pipe when taking surveys, sliding, performing downlinks, taking formation integrity tests / leak off tests, diagnosing tool failures, re-logging, etc. If more rigs were equipped with wired drill pipe and third party companies had a broader selection of off-the-shelf wired equipment, developments with few wells could be drilled with wired drill pipe telemetry economically. More can be read on the topic in section 3.3.

3.1.1 Possible Benefits of WDPT

- Saving time on downlinking, taking surveys, performing rotational check-shots

- No need to spend time on surface to download data, as this is done in real-time. However, with the current MWD tools, the data must still be downloaded on surface. The reason being that there might be zones where the wired drill pipe did not deliver optimal signals and thus create missing gaps in the logs
- No need to reduce ROP to get enough data density over a zone of interest
- Should WDP telemetry fail, mud pulse will take over, ensuring full redundancy. When running only mud pulse telemetry, there is no back-up system should the tools fail
- WDPT allows for trouble shooting of downhole tools and thus can sometimes solve the problem without POOH
- Higher frequency of directional surveys and check-shots reduces the ellipse of uncertainty. This is the uncertainty of the wellbore location downhole. If the uncertainty area is crossed, the probability of drilling into another well increases
- Instant control of downhole tools result in superior directional control allowing precise wellbore placement and resulting in improved hole quality
- Real time memory quality data enhances reservoir navigation leading to increased reservoir exposure and production potential
- Time laps log provide the ability to monitor the condition of the open hole and identify downhole deterioration

3.1.2 Posible Benefits of Along String Measurements

- Added benefits to well control
- Added benefits to managed pressure drilling
- Determination of pack-off point
- Enhanced ECD management
- Fingerprint enhancement
- Identification of lost circulation- or influx zone
- Monitoring of annular pressure fluctuations during connections and tripping
- Real-time monitoring of hole cleaning efficiency and hydraulics
- Wellbore pressure measurements over the entire open hole section

A range of these points will be discussed in detail in section 4.

3.1.3 Observed Effects

Reservoir placement / navigation When drilling horizontal production drains it is important to place the wellbore accurately within the zone of interest, the hydrocarbon bearing zone, to ensure optimized drainage. The placement of the wellbore is mainly made easier by the wired pipe through the increased bandwidth, which allows more data to be transferred to the surface during drilling. Hence, making the decision process easier.

At the time of this thesis the impact of the WDPT for geosteering on Martin Linge has not reached its full potential as some of the "high end" geosteering tools still are to be made available for the technology. However, as most of the standard geosteering logging tools are set up for the WDPT, it is possible to set up the standard mud pulse telemetry to prioritize the data from the tools without the WDPT set-up. In that way, allowing more data to arrive on surface.

The WDPT also allows for quicker downlinks, which makes it possible to apply directional changes faster than the time needed for downlinks using the conventional mud pulse telemetry. In addition, the instant communication through the WDPT also makes it possible to drill without having to adjust pump-rates or ROP when making the directional adjustments

Saving BHA trip During drilling of a well, the real-time data transmission of the resistivity tool was lost. As this log were to be used in correlation for defining the section TD it was considered to pull the BHA to replace the failed component. However, as the direct communication from the WDPT allowed the LWD personnel to retrieve the memory data from the tools, they could do a real-time processing of the data and deliver it to the operator for analysis and interpretation. This was, as far as the involved engineers knew, the first time something like this had been done. Hence, a trip in and out of the well was saved. As the bit depth at the time was 1859 m MD, the trip would have taken a substantial amount of time.

Avoiding formation fracture When drilling the A-10 well at 2597 m TVD, the readings on both ASM's and pressure while drilling at bottom hole, showed higher equivalent circulating density (ECD) than modelled and measured at surface. As the same trend was recorded on all three pressure sensors downhole, it was deduced that the readings were most probably correct. The ASM pressure sensors was used to calibrate the equivalent static density (ESD). If the higher than expected ECD was not measured at the ASM, the flow rate would not have been decreased, resulting in fracturing the well at the shoe, consequently loosing the section.

ECD Management When drilling the horizontal drain, concerns were raised that the necessary ECD was too high to drill the section to target depth. The pressure while drilling tool in the BHA showed ECD values that would fracture the formation before reaching the target. However, from the ASM measurements, it was seen that ECD values around the drill pipe was 0.03 [s.g] lower than around the BHA. Thus, it was deduced that drilling on would not damage the formation. Hence, understanding of ECD downhole allowed drilling section to desired TD.

3.2 Reliability

When estimating system reliability, the definition of failure becomes an important concept. For the wired drill pipe network, failure can be defined as a signal interruption caused by an inadequate or undesirable performance of one of its components. This degrades or interrupts the performance of the overall data transmission. Once a signal interruption occurs, the wired pipes ability to deliver broadband downhole telemetry in a timely and accurate manner is compromised. Because of the redundancy option, mud pulse telemetry, the drilling process itself does not have to be interrupted.

To provide reliable and a stable network during operations, the systems health and operability is verified during tripping in and pulling out of hole. The system assessment is done by the means of a wired test fixture. This is a test that is typically performed every few stands and takes less than thirty seconds.

Field service personnel use the test results to determine network connectivity and possibly identify point and cause of failure.

The networked drill string components perform mechanical functions like normal, non-wired drill pipe, and are removed if they suffer excessive wear or damage. Networked components can also incur electrical damage, which by means of the test above is identified and subsequently these items are isolated.

Table 3.1 lists the interruption types and classifications typically identified by field personnel. The components that have failed are either categorized as mechanical failure or electrical failure.

Table 3.1: Network drill string interruption classification and types

Mechanical	Electrical
Gross Physical Damage	TT Failure
Coil Broken/Loose	S-Parameter Failure
Coil Wear/Damage	S-Parameter Irregularity
Pipe Wear/Hardband/Body	

The references to electrical interruptions in the table are tests being performed by field personnel. Scattering parameter tests (S-parameter) and telemetry tester (TT). These have been defined to assess a wired components operability and electrical characteristics and provide immediate feedback to enable rapid maintenance. TT-classified components have string communication failure, S-parameter failure is signal insertion failure, while S-parameter irregularity is signal insertion irregularity. [5]

3.2.1 History of WDPT Reliability

McCubrey et al. [5] has done a study of system reliability on 65 wells from 2008 to 2011. Results showing an increasing trend in reliability. The data has been gathered from field reported drilling service reports, completed at the end of every shift while drilling a well. These reports includes information about the system, context for failure and captures issues or interruptions caused by networked drill string system components.

Figure 3.6 provides a consolidated view of the reliability metrics uptime, mean time before failure (MTBF) and non-productive time (NPT) through a series of commercial deployments. The pattern show an trend of increasing reliability. The letters surrounded by ellipses are operational challenges and network improvements, which is explained in text under the graph.

The x-axis of figure 3.6 is the cumulative depth drilled with wired drill pipe telemetry, where the vertical red lines point out the calendar years. The end point of the x-axis corresponds with December 2011. The width between the lines indicates the level of drilling activity with wired pipe. The left side y-axis presents the MTBF in black. The blue curve shows the network uptime. This metric is affected by how the drill string is used after failure is detected. If the networked drill string is immediately tripped and repaired the uptime impact for a service interruption can be very low. If drilling continues with the back up mud pulse telemetry system, then the wells total uptime can be dramatically lowered in a single run.

The right side y-axis has a single set of labels for the NPT and item removals. The NPT in green shows where the sting maintenance or repair has consumed rig time, and the removal count in red shows number of items removed. [5]

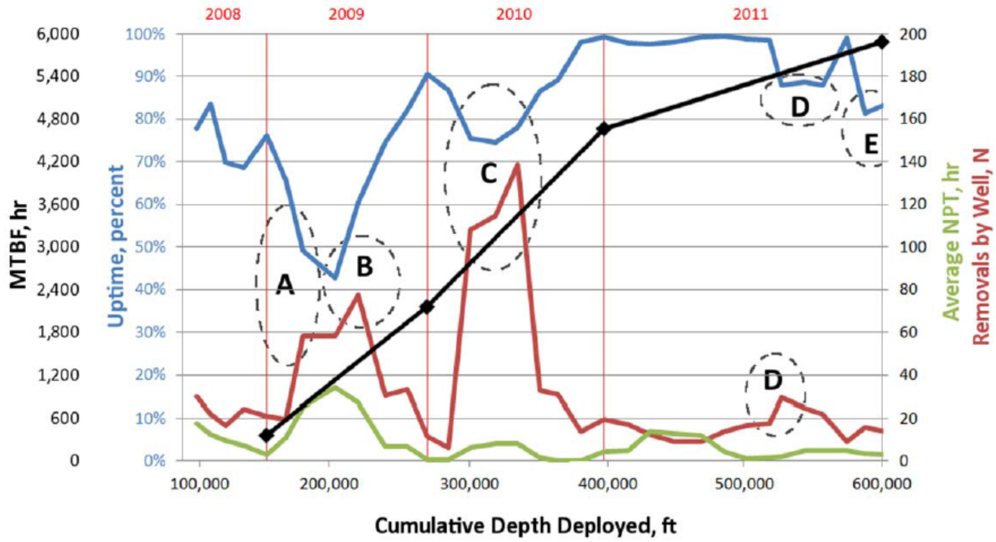


Figure 3.6: NOV WDPT statistics for uptime, average NPT and MTBF from 2008 to 2011 [5]

A Previously, a steel component was used at the end of the coaxial armoured cable, which provided a vulnerability to electrical shorting in the event of an insulation loss. This vulnerability was later eliminated through a design improvement

B During a networked drill string deployment using exceptionally high mud chloride levels, the drill strings armoured coaxial cable experienced stress corrosion cracking. Removals required significant downtime and NPT. This incident triggered a materials review which inspired a subsequent design change.

C This ellipse shows a deployment where a string was substantially over-torqued, which directly affected service reliability, removals and associated removal NPT.

D Dip in plot because of stress corrosion-cracking incidents during long term storage, after incomplete cleaning. The stress occurred because of runs with high-doglegs. As a result, the armoured coaxial cable was re-designed and tested in a high-dogleg environment.

E Severe miss calibration of an iron roughneck led to torsional damage to the networked drill string tool joints.

From BP's experiencec in Edwards et al. [9], four out of five trials have been deemed successful from the point of the technology working. The basis for this experience is the utilization of wired pipe on ten wells in five different locations within BP, during a period between 2007 and 2010. The only exception was the North Sea deployment where an older wired pipe design was used, proving unreliable due to fundamental design issues, which has been rectified since then.

Other than the North Sea deployment, experiences have been that the pipe generally works if handled and maintained properly. The best reliability has been shown in the deep water Gulf of Mexico deployment. These wells were moderately deviated with gentle dog legs, and generally good hole conditions. From this, BP has concluded that the environment of the wells might have contributed to the good reliability of the network. Other contributing factors could also have been the high day rates in deep water and the high visibility of the project, adding an extra incentive from both operators and vendors to ensure everything went smoothly. Of the six BHA runs in the intermediate and reservoir hole section to depths of 20 000 ft, five runs had 99-100% network uptime and the sixth had 85% uptime.

Experiences showed that a brand new string was generally reliable, gave network uptime rates of 90-100%. However, as the equipment continued to be used it was generally found that reliability decreased. Drill pipe management and maintenance became a key component for mitigating the issues. A rule of thumb was established, stating that drill pipe should be rotated out of service every 750 hours of use or every 500 hours of heavy weight. Dual activity capability was also deemed a significant advantage, being able to seamlessly rotate stands in and out of service.

Most of the reliability issues were associated with the connections and the major issues were described as follows:

- Corrosion of steel flares
- Downhole over-torquing of connections causing damage to coils
- Damage to coils caused by pipe handling on make up/breakout
- Top drive issues

The high speed telemetry steering committee, consisting of employees from several different oil companies on the Norwegian Continental Shelf, deemed the reliability to be the most important aspect regarding the operation of wired drill pipe. What is missing right now is someone providing the full package; delivering the pipe, wiring of the pipe, MWD- and LWD tools and also providing for the network uptime.

3.2.2 Reliability on Martin Linge

On the Martin Linge field wired drill pipe operations have been planned in the sections 26 in and in the following smaller diameter sections. At the first stages of batch-drilling the wired drill pipe experienced a substantial amount of downtime. This can be seen in figure 3.7. The inspection report given in January 2015 shows 127 joints set aside during drilling because of suspected electrical performance and sent to shore for inspection. The results are presented in table 3.2.

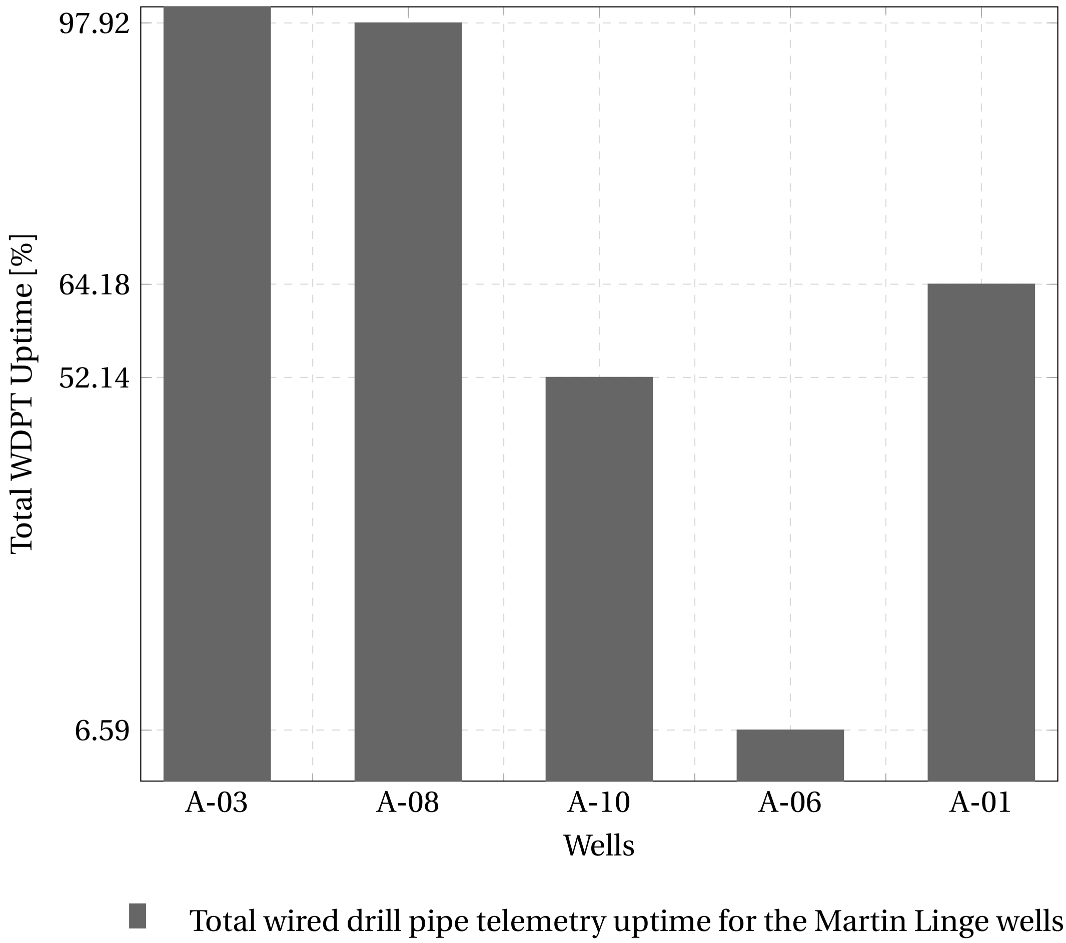


Figure 3.7: Total telemetry network uptime per well, from 23rd of September to 31st of January [10]

These wells were drilled at different time intervals, namely:

A-03 23rd of September to 6th of October

A-08 7th of October to 14th of October

A-10 15th of October to 26th of December

A-06 5th of November to 12th of November

A-01 27th of December to 31st of January

18 of 127 passed the mechanical inspection, 109 of 127 exhibited mechanical damage of various types and 44 out of the 109 damaged joints was due to over-torque. What is worth mentioning is that when running conventional drill pipe, the drill pipe would be sent onshore on a defined inspection schedule, for example every 1000 hours drilled. That would probably be the first time any mechanical damage would be found. However, when using wired drill pipe, mechanical damage will be identified sooner, as damaged pipe is likely to cause a failure in the wired drill pipe network.

Table 3.2: Results from inspection of wired drill pipe [11]

Pin Condition	Box Condition	Quantity	Percentage [%]
Over Torque	OK	27	21
Reface	OK	17	13
OK	Thread Damage	14	11
Over Torque	Thread damage	10	8
Reface	Thread Damage	9	7
OK	Reface	8	6
Over Torque	Reface	7	6
Reface	Reface	6	5
Electrical Failure	OK	6	5
Thread Damage	OK	4	3
Thread Damage	Reface	1	1

Some of the reasons for the high numbers in damaged pipe at the beginning of the Martin Linge operations can be downhole events. The events include stuck pipe in early October and another stuck pipe incident two months later, as well as high vibration levels and stick slip events. In addition, the fact that the rig was brand new and the crew not experienced with the handling of wired drill pipe could have had an effect.

After conversations with Baker Hughes' wired pipe engineer who was offshore responsible for the network uptime, a few operational challenges were highlighted:

- Protectors must always be used to protect the coils
- Drill pipe, subs and similar wired tools must be handled with extra care
- Extra care must be taken when making up stands. The pin and box ends need to be centralized before make up.
- Washing of the pipe/top drive after stands are made up

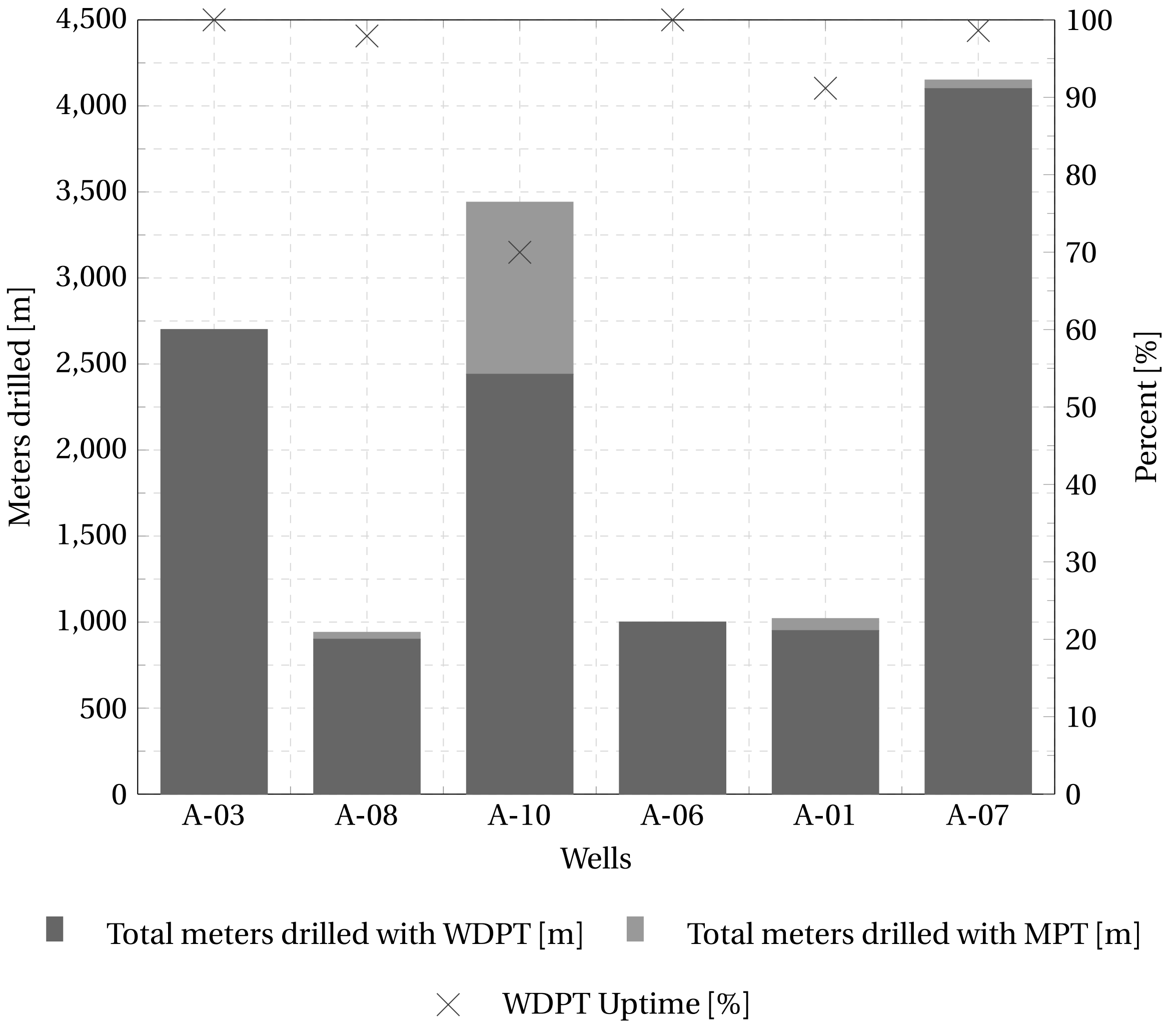


Figure 3.8: Total WDP telemetry network uptime on Martin Linge per well, from February to 6th of May [10]

The wired pipe engineer thought the reason behind the increase in telemetry network uptime was that the roughnecks had taken an ownership of the pipe. At the beginning they were unfamiliar with the equipment. In the end they understood that this was a delicate piece of equipment that needed careful handling.

Conversations with the roughnecks revealed that to make everyone take ownership of the pipe and network, a proper understanding of added benefits of the network and ASM's is a critical factor. Especially knowing more details or practical things as how the real time image logs are used. At this point they had not really understood the benefits of using wired pipe.

Experiences from other operating companies have shown that when the pipe is put away and not used it can experience some downtime before getting the network up and going. At the Martin Linge field development the wired drill pipe telemetry system was taken into use at the 26 in sections, which ensured that everyone got familiar with the equipment before starting to drill the more critical sections. A continuous operation of the wired drill pipe network also ensures that the pipes are continuously monitored, thus providing the benefit of being absolutely sure that the network works when you want it to.

As figure 3.8 shows, the total network uptime at Martin Linge is quite good, despite the start-up problems which are included in the calculated numbers. For the A-10 well, the uptime is very low because when the wired pipe network failed, the decision was made to drill on with the back-up mud pulse telemetry system. The current total wired pipe telemetry average uptime is recorded to be 91 %, which looks to be close to the average of the year 2011, given in figure 3.6.

The average maintenance hour for WDPT on the Martin Linge field up to May 6th was 5.1 hours per well. The distribution of network activities as reported by the daily drilling reports can be shown in figure 3.9.

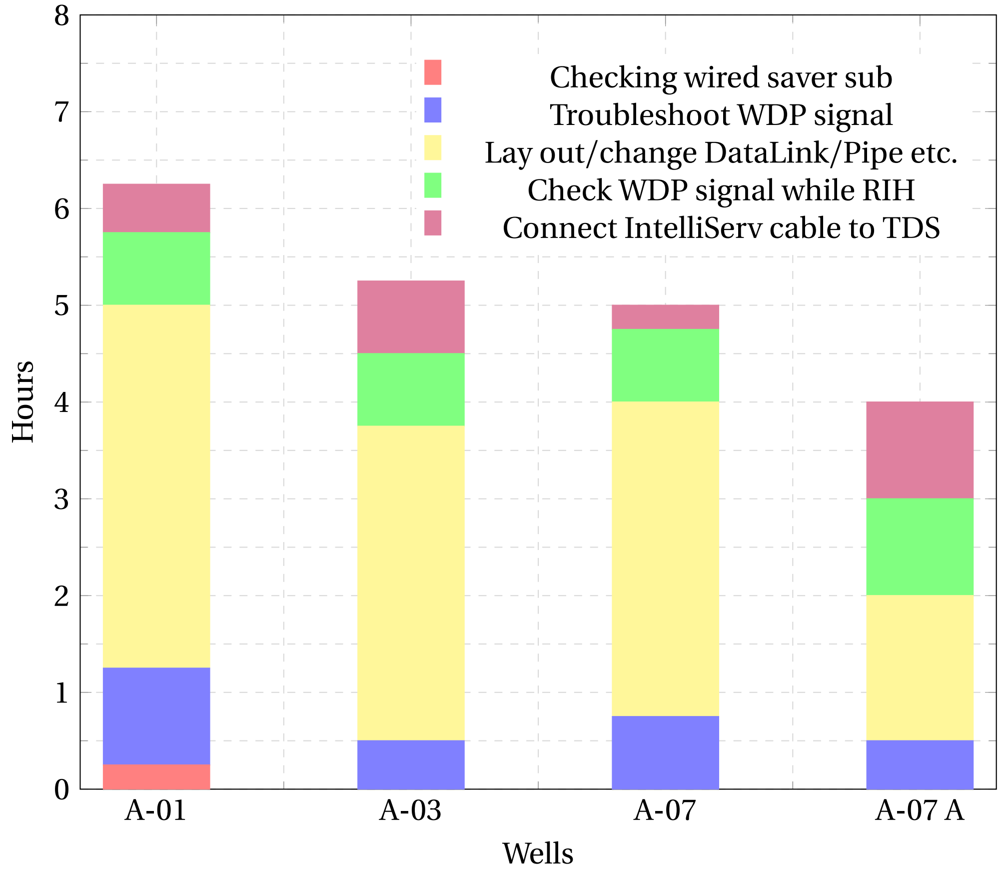


Figure 3.9: Distribution of network maintenance time [10]

In figure 3.9, RIH is running into hole and TDS is top drive swivel.

Until May 6th, the A-07 well was fully completed at 3800 m MD, with the A-07 A being a pilot hole. The A-03 well was drilled to 2100 m MD and A-01 was drilled to 2200 m MD.

Lessons learned from the Martin Linge operations include:

Third party responsible Making a third party responsible for network uptime has shown to be a great benefit. Because of this, the network uptime is in the best interest for more parties involved than just the operator. Thus, a whole new incentive is established for making the uptime as good as possible.

Pipe handling Wired drill pipes are more sensitive than conventional drill pipe and must, with the current technologies, be handled that way. This must be presented to everyone involved in pipe handling at an early stage. Based on feedback from the roughnecks, it is clear that better handling of the equipment might have been provided if they knew about the advantages of using wired drill pipe, and why the uptime is critical.

Early start-up Wired drill pipes telemetry is sometimes used by the operators only in the sections where they are perceived as most beneficial. Thus, it is more difficult to maintain a healthy drill string. Total has used the wired drill pipe telemetry system from the 26 in sections, which enabled a learning phase for all people involved. Low network uptime was seen in the beginning, but by using the pipe in the non-critical phase, the flaws in the systems were spotted early and effort was put into mitigating them. By using the wired pipe telemetry system continuously, the health of the telemetry system was continuously monitored by the wired pipe engineer, and parts of the pipe experiencing failure or bad signals were removed.

3.2.3 Second Generation Wired Drill Pipe

Recently, a second generation of wired drill pipe items have been made. Upgrades have been done to the network controller, DataCable, coils and the DataLink.

The network controller will provide easier maintenance and provide control of the network from surface.

For the DataCable, new enhanced armour material provides increased resistance to corrosion and damage.

One of the items that are changed the most, is the coil. It has been recessed in the pin end, and slightly elevated on the box end. This will probably reduce the mechanical wear done to the coil, during pipe handling. The steel around the coil will take the hit instead of the recessed coil itself. The material of the coil is changed, to improve its robustness and durability. The coil is now possible to remove and change without damaging the pipe. In addition, the interval between the coil and the groove has increased. This is done to allow for mechanical deformation and is one of the proposed solutions for the high over-torque wear shown in table 3.2. [12]

It is believed that with these design improvements, the uptime will be taken to another level. A four month trial in the US has shown a promising result of 99 % uptime.

Figure 3.10: Second generation coil

These second generation wired pipe have been ordered by Lundin and will be taken into use on the Norwegian continental shelf in August.

3.3 Time Savings

There are several possible ways to save time using wired drill pipe. The different categories can be divided into:

Data transmission time WDPT transmits signals faster than MPT, therefore WDPT use less time in sending data. There is also no need to repeat surveys because of bad / lost signals and noise.

Increased drilling performance High speed transmission from the LWD tools diminishes the need to slow down ROP to get good quality readings over an area. Continuous inclination data gives better confidence in well position and thus allows for higher ROP.

Drilling time reduction Number of bit / BHA runs can be reduced by trouble-shooting downhole equipment, sampling can be adjusted, etc. Hole cleaning optimization can be performed by using the ASM's and trip speed can be optimized by looking at the surge / swab pressures in real-time. [13]

The time analysis of the WDPT is based on three wells on the Martin Linge project, which are partly drilled with wired drill pipe telemetry. These are compared with an appraisal well drilled a few years back. Offset well information is based on end of well reports, daily plots and daily applied drilling technology (ADT) reports. Data transmissions include surveys, formation integrity tests (FIT) / leak off tests (LOT) and downlinks. [10]

The following lists form the basis for calculation of telemetry time in offset wells:

Surveys

- Average telemetry time / MWD survey was 3 minutes
- Average telemetr time / Gyro-MWD survey was 10 minutes
- Check / repeat surveys was performed

Downlinks

- Average telemetry time / off-bottom downlink was 3 minutes

- 20% downlinks were performed off bottom

FIT / LOT

- Data transmitted to survey / 15 minutes each section

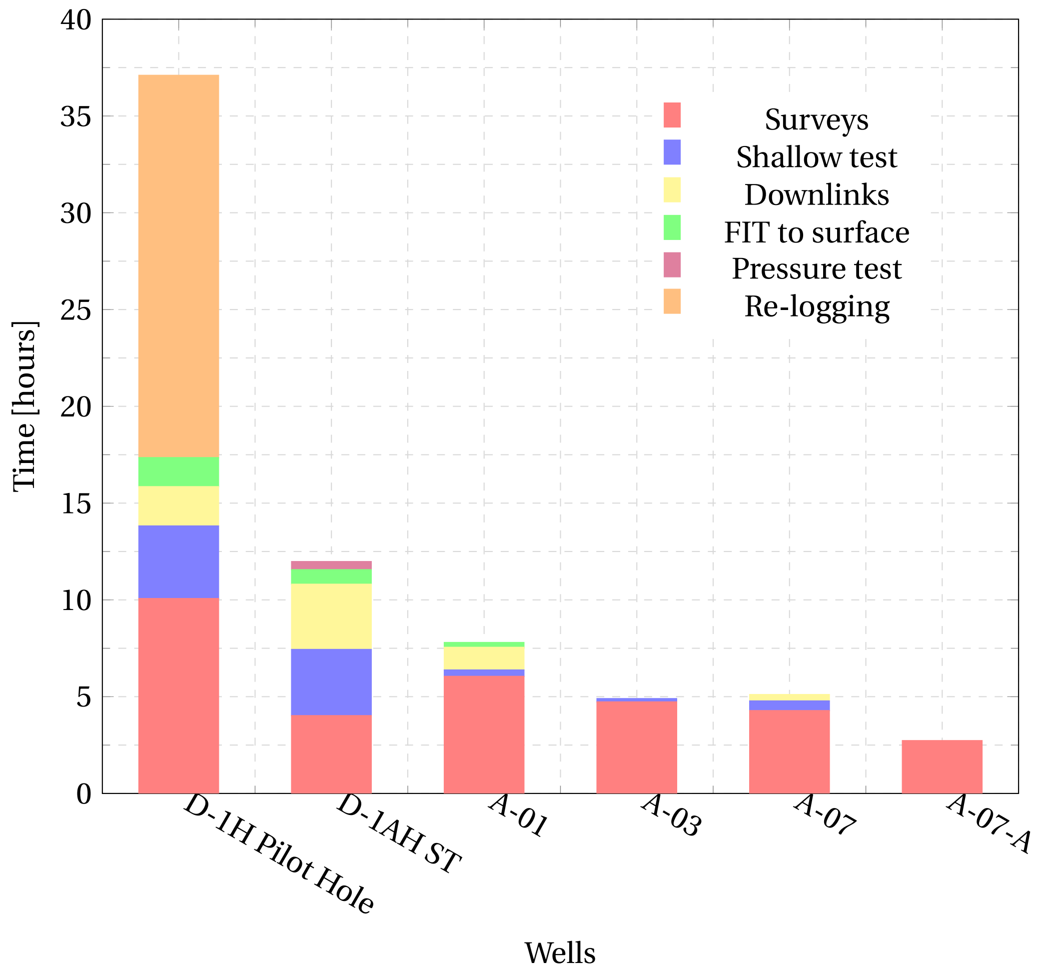


Figure 3.11: Telemetry time per well [10]

Figure 3.11 shows what the telemetry time was used for during the drilling of the different wells. It can be seen that the time spent on transmission was far less in the wells drilled with WDPT, largely due to the re-logging on well D-1H Pilot Hole. This gives an average telemetry time per well for the offset wells at 7.69 hours/1000m, while the Martin Linge wells have a rate of 1.82 hours/1000m per well, which can be seen in figure 3.12.

The reduction in telemetry time thus becomes $7.69 - 1.82$ [hours/1000m] = 5.87 [hours/1000m]. For the typical oil well on Martin Linge, the first one drilled to 3854 m MD, the time savings would be 5.87 [hours/1000m] $\times$ 3.854 [1000m] = 22.62 [hours]. With the current costs on the NCS for both rig, personnel and equipment an rough estimation of daily costs for drilling operations is 5 500 000 [NOK/24hours] [14]. This gives an overall saving per oil well of $\frac{22.62}{24}$ [Day] $\times$ 5 550 000 [NOK/Day] = 5 200 000 [NOK]

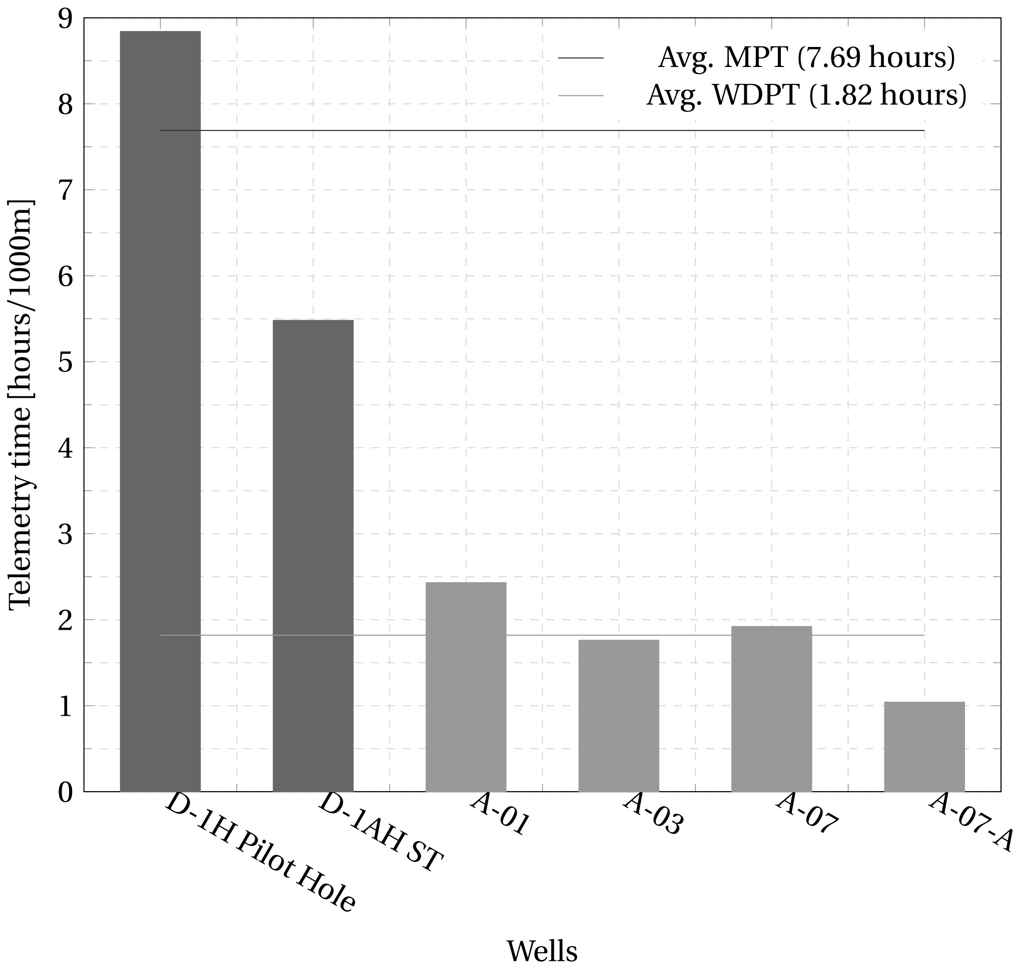


Figure 3.12: Telemetry time in hours / 1000m drilled [10]

4 Along String Measurements

The development of wired drill pipe telemetry has enabled the introduction of sensor measurements along the string. On the Martin Linge field, the measurements currently available at the MeasurementLinks are pressures and temperatures.

Previously it was only possible to have measurements at the BHA. This has led to reliance on modelling to help understand what happens in the wellbore. The development of wired drill pipe and along string measurements have made it possible to observe the downhole environment not just at the BHA, but also along the wellbore.

This might lead to development of new methods and techniques for surveillance of cuttings transport, borehole stability and other applications. In general, this will help understand the wellbore environment and impact modelling.

This section will largely focus on data analysis from the pressure sensors along the string and the interpretation thereof.

4.1 Optimal Placement of MeasurementLinks

The placement of the MeasurementLinks is of utmost importance. Depending on what the focus for utilizing along string measurements is, the sensors can be distributed in different ways.

- Sensors concentrated in open hole
- Sensors concentrated in cased hole

- Sensors concentrated in either open hole or cased hole with coverage in the other
- Sensors spaced evenly along the drill string

All of these placement options have advantages and disadvantages depending on the intended application of the data. Trials have shown that with respect to solids control and hole cleaning an even spacing of the sensors is most beneficial. Having pressure sensors in the shallower, cased sections of the wellbore is important to verify the transportation of cuttings to surface. Solids travelling up the well propagate an increase in pressure which can be measured at the MeasurementLinks. This way a particular volume of solid material can be observed all the way from BHA to surface, and location of pack-off and / or cuttings settling can be identified.

It is important that the placement of sensors supports the use for which they are intended. If losses are of primary concern the sensors should be concentrated in the open hole, to establish the position of loss zone, making it easier to treat. However, studies have shown that evenly spacing the sensors will generally provide enhanced monitoring capability for various downhole events. [15]

For the Martin Linge wells, Total has invested in three MeasurementLinks. These are, together with the DataLinks, spaced out at approximately every 500 m. This is to ensure that the signal is good, as MeasurementLinks boosts the signal the same way that DataLinks do. So the configuration of MeasurementLinks can vary, but they are usually positioned like the positions given in table 4.1.

Table 4.1: MeasurementLink positions in the A-10 well

Component	Length [m]	Position from drill bit [m]
ASM1	1.8	234
ASM2	1.8	602
ASM3	1.8	1102

The best option for distributing these pressure sensors is an even distribution, such that poor hole cleaning can be observed. With a limited amount of sensors, an even distribution also makes it possible to have more measurements distributed in the well for ECD optimization and to be used as baseline for managed pressure drilling operations.

4.2 Accuracy of Sensors

The current accuracy of the downhole pressure sensors, given from the ASM specification sheet in the appendix, is given to be 0.01% FS. This means that it is 0.01% of Full Scale. The full scale of the pressure sensor being 25 000 psi. This translates to $\frac{0.01}{100} \times 25000\ [\text{psi}] = 2.5\ [\text{psi}]$. In bar that would be $\frac{2.5\ [\text{psi}]}{14.5\left[\frac{\text{psi}}{\text{bar}}\right]} = 0.172\ [\text{bar}]$.

This can be said to be a very small inaccuracy. If the assumption is made that this inaccuracy is constant along the wellbore, this has an effect on the calculated ECD. Although the pressure inaccuracy is constant along the wellbore, the calculated ECD will differ at different depths. This is given from the following equation

$$\text{ECD} = \frac{\text{P}}{\text{g} \times \text{h}} \tag{4.1}$$

where ECD is equivalent circulating density given in [s.g], P is the pressure accuracy given in [Pa], g is the gravitational constant given in $\left[\frac{m}{s^2}\right]$ and h is the true vertical depth of the sensor location given in [m].

The ECD for the pressure inaccuracy at different TVD's are then plotted in figures 4.1 and 4.2.

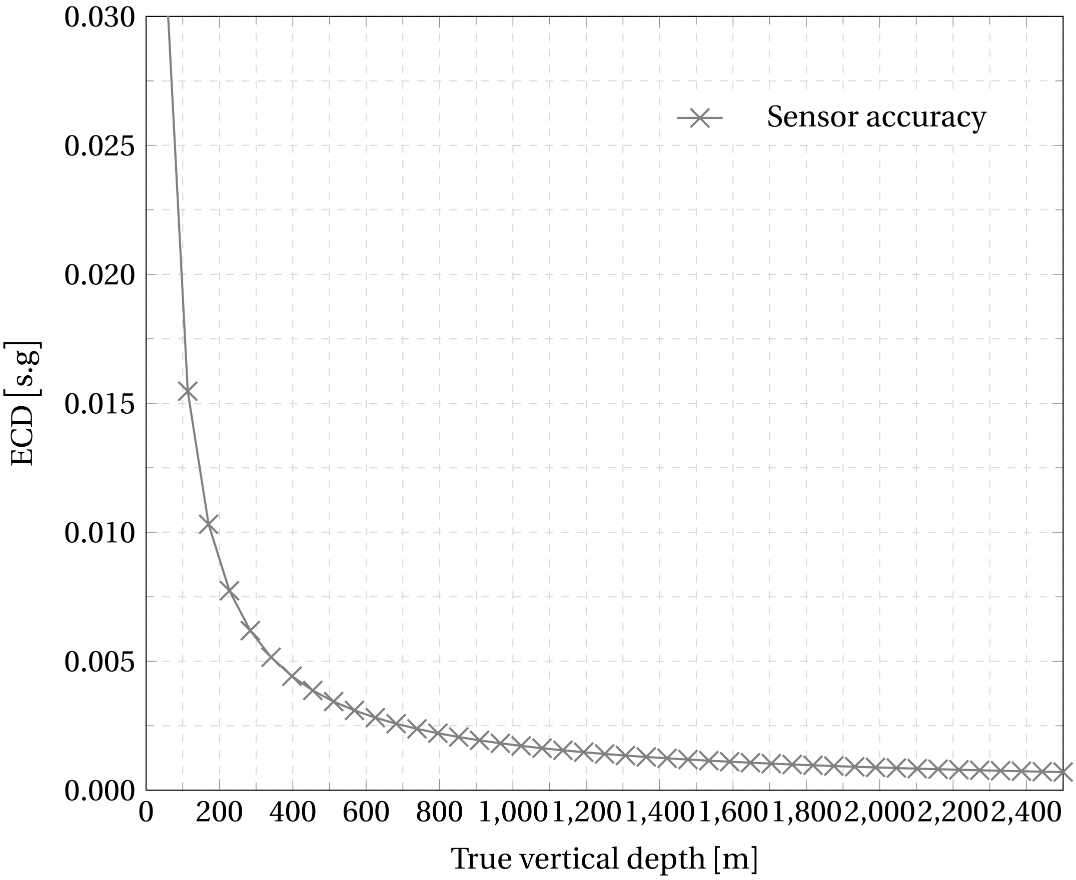


Figure 4.1: Accuracy of pressure sensors downhole, 0 < ECD [s.g] < 0.030

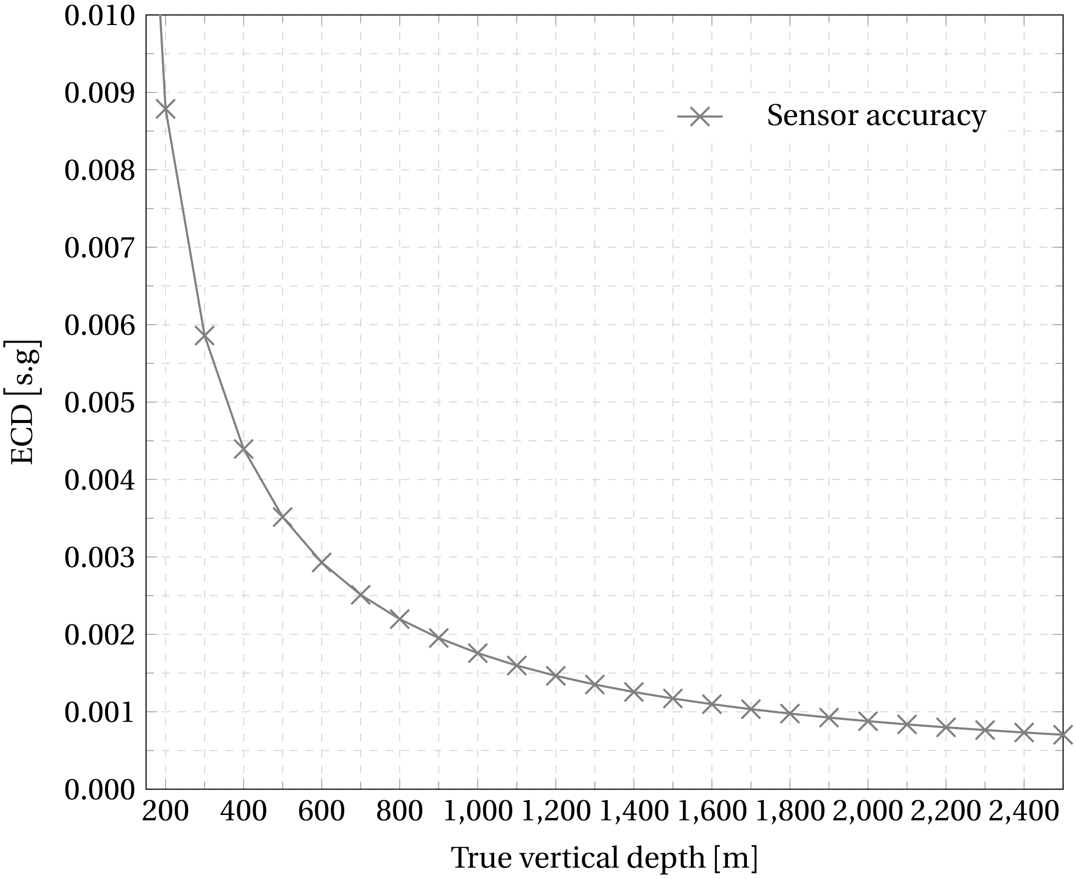


Figure 4.2: Accuracy of pressure sensors downhole, 150 < TVD [m] < 2500

It can be seen that after drilling down to a certain TVD, the added or subtracted ECD at the ASM's are very small. The sensors are therefore very accurate when it comes to calculating ECD downhole after a certain depth, and the data can in theory be used very precisely. However, data from shallow ASM's should be used with care, since the inaccuracy of ECD measurements at shallow depths can be very large, above 0.03 s g.

The pressure sensors could also be calibrated to be more accurate at the depths where they are most needed. This would be in the deeper sections, where precise measurements are more critical. Thus, the ECD change because of the different inaccuracies might be distributed something similar to that seen in figures 4.1 and 4.2.

The reason why this ECD calculation inaccuracy can be important is when it comes to plot analysis to measure poor hole cleaning and other similar analysis. The ECD is then often looked at as opposed to pressures, as in Coley and Edwards [15].

When trends and changes in ECD are measured at shallow depths and compared to ECD at deeper depths, it is important to have in mind that the shallower ASM's have a larger ECD inaccuracy value. This is especially important when developing algorithms and systems for evaluating possible ECD trends and changes.

4.3 ASM and Managed Pressure Drilling

Wired drill pipe can address several of the challenges related to communication encountered in MPD since it [16]:

- Provides for transmission of data independent of drilling fluid type or flow rate.
- Facilitates bi-directional communication to increase the level of interaction with the downhole equipment.
- Offers at least three orders of magnitude higher bandwidth than other telemetry methods, improving the amount of information transmitted and enabling better resolution and clarity of downhole conditions than ever before.

4.3.1 Back Pressure Monitoring

To calculate the surface back pressure necessary to maintain a stable downhole pressure, it is vital to know the static mud weight or static pressure downhole, in real-time. This has not been accessible previously, because the pressure could not be transmitted in real-time by MPT. The reason being that it is dependent on a steady flow of drilling fluids. With the wired drill pipe technology it is possible to measure the downhole pressure when the mud pumps are off, thus observing the actual pressure downhole without the added frictional pressure. This enables an optimization of back pressure selection. This allows for a more stable downhole pressure, resulting in a more stable borehole.

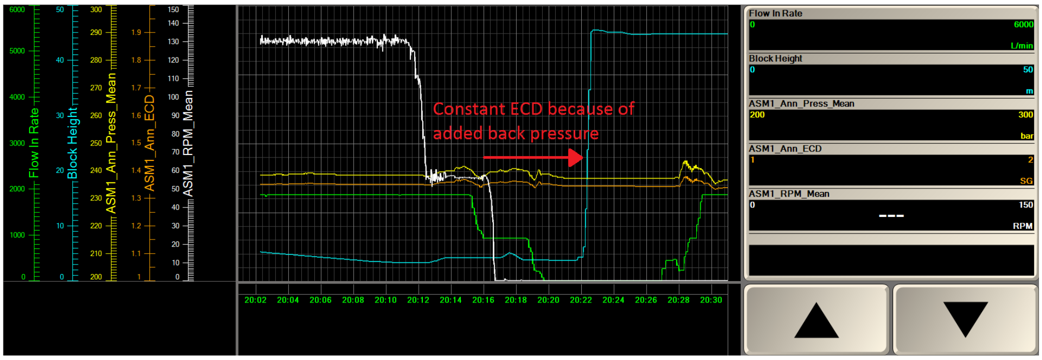


Figure 4.3: Using surface back pressure while building stand

Figure 4.3 shows where the pressure readings from the ASM's can be taken in real time to be used as the baseline for surface back pressure adjustment by the MPD system. The x-axis shows the time, while the y-axis shows various downhole measurements. At about 20:17, the RPM is decreased to zero rotation and a few minutes later at approximately 20:20 the flow rate is shut off. This should result in a decrease in ECD as these parameters are substantial in the

$8\frac{1}{2}$in section, which is the interval where the plots are taken from. A reduction in flow rate, and RPM, will cause a decrease in frictional pressure loss, which can be seen in equation (4.9).

As the pressures in a MPD operation is given by [17]

$$\mathrm{ECD} = \rho_{\mathrm{mud}} + \frac{\Delta \mathrm{P_f}}{\mathrm{g} \times \mathrm{h}} + \frac{\mathrm{Back\ \ Pressure}}{\mathrm{g} \times \mathrm{h}} \tag{4.2}$$

where ECD is given in [s.g], ρ_{mud} is given in [s.g] the frictional back pressure $\frac{\Delta \mathrm{P_f}}{\mathrm{g}\times\mathrm{h}}$ is given in [s.g] and the $\frac{\mathrm{Back\ \ Pressure}}{\mathrm{g}\times\mathrm{h}}$ is the additional pressure from the MPD system, adjusted by the chokes and MPD flow system topside, also given in [s.g].

The back pressure can be adjusted so that when loosing the fricitonal pressure drop when decreasing RPM and flow rate, the back pressure from the MPD system can be increased to keep the pressures downhole stable. The interval where back pressure is applied, is shown in figure 4.3.

By looking at these readings in real-time with the wired drill pipe telemetry system, it is possible to monitor any changes in downhole pressure and adjust the choke system accordingly.

4.4 Data Analysis

When analysing data from downhole sensors it is important to understand what the measurements represents. A sensor gives the opportunity to quantify a specific parameter at a given point in time and space. One of the parameters measured by the ASM's are pressures.

A measured annular pressure represents the accumulated effects of anything occurring in the borehole that impacts the force exerted on the sensor. In a situation where the well is being circulated, the pressure sensors will provide data comprising both the hydrostatic fluid column, any frictional effects caused by the circulating fluid and back pressure from the managed pressure drilling system, if used. Thus, the readings quantified by the sensors will be an accumulation of different pressure events occurring at the same time, each with a potentially changing magnitude in time. The hydrostatic fluid column will generally remain static while the frictional pressure drop can change depending on flow rate, rotation of the drill string, temperature etc.

The frictional pressure drop are the accumulated pressure drops from drill pipe and annulus. As the pressure sensors on the MeasurementLinks can measure both inside and outside of the pipe, this is an important fact to notice. These are affected by liquid rheology properties, lengths and inner diameters of the pipes and BHA components from the mud pumps to the drill bit. Some BHA components will generate additional pressure losses due to outer diameter variances, examples being the downhole motor and MWD tools. BHA components may also have smaller inner diameters than regular drill pipe, causing some additional pressure loss. When cuttings mix with drill mud, the average density increases and the static pressure in the annulus will increase slightly due to this. [18]

The analysis of pressure measurements is a matter of decomposing the different parameters that influence the measurement, and give a value to the different components. These components can then be individually monitored for change. This process is used to create a baseline measurement. To be able to effectively use the measured value an expected value needs to be established. This is a very complex and time consuming task when interpreting sensor data. When a good baseline is established, with well understood limitations and assumptions, the analysis simply becomes a comparison between expected and measured data. The more detailed the components in the baseline are described, the easier it becomes to find the cause of deviation from the expected value. [15]

When a new well section is started, fingerprinting is often done, this is described in section 4.4.6. Finding these values can provide a good baseline for ECD prediction.

A baseline value can also be acquired from the company delivering drilling fluid. Computer simulations, with sophisticated hydraulic models, are then deployed to estimate the expected values. These are then used to ensure that the pressures in the well match the expected values from the simulations. When along string pressure measurements are available, these measurements can be used to check and calibrate the simulations and / or the fingerprinted values so that abnormalities can be found as fast as possible.

This comparison of simulated and actual measurements should be done in real time to get the best use of the data. The comparison will then reveal any changes from the expected values and the ASM measurements and check the well for stability problems such as poor hole cleaning and cavings. For this to be as easy as possible, both the simulations and pressure measurements could be run simultaneously and be shown in the same screen. This requires a good cooperation between the mud company and logging / ASM company. For this to be as easy to analyse as possible, interpretation guidelines should be made.

You can read more about this in section 4.4.6.

Further development could be done on this so that an algorithm delivers a warning when the measurements differ from the expected values. These algorithms could then calculate if there is any measurements in particular that is responsible for the change in pressure. Thus, it could be known in a very short period of time what the problem is.

4.4.1 Hole Cleaning

Hole cleaning theory When drilling, the drill bit crushes the rock formation into small fragments called cuttings. The drilling fluid is pumped through the drill pipe and circulated back through the annulus to the surface facilities, such as shale shaker and mud pits. The main purposes of this drilling fluid is to maintain well pressures, in order to avoid well collapse and fracture of the formation. In addition, cool and lubricate the bit and string and lift cuttings to the surface. The ability of the fluid to lift cuttings is referred to as the carrying capacity of the fluid. The ability to predict the effective cleaning efficiency of a given mud and flow rate is very important. The prediction is performed by calculating the critical cutting transport velocity. Critical transport fluid velocity (CTFV), also called minimum transport velocity (MTV), is defined as minimum fluid velocity required to prevent cutting bed formation. The minimum velocity allows cuttings to be transported upwards. Hence, proper design and implementation of cuttings transport is very important for the overall success of the drilling operation. [19]

In vertical and near vertical wellbores, the slip velocity concept is used to represent the MTV. The transportation velocity is given as

$$v_T = v_{fluid} - v_{slip} \tag{4.3}$$

where v_T is the transportation velocity, v_{fluid} is the velocity of the fluid in the annulus and v_{slip} is the particle slip velocity.

Three different methods of estimating the slip velocity can be found in API [20], Ahmed and Takach [21] and Hareland [22].

When inclination is more than 30 degrees flow regime, fluid rheology, rotation of drill string amongst others are also controlling inputs, in addition to the flow rate. Transportation of cuttings in the annulus then becomes a very complex process, being affected by many parameters. Some of these parameters are illustrated in table 4.2.

Table 4.2: Parameters in transportation of cuttings

Fluid Parameters	Cutting Parameters	Operational Parameters
Mud Density	Density	Angle of Inclination
Rheology	Size	Pipe Rotation
	Shape	Rate of Penetration
	Concentration	Eccentricity of the Hole
	Bed Porosity	Flow Rate
	Angle of Repose	Hole Size / Casing Size

The transport ratio can be found by defining a rheology factor, angle factor and mud weight and can be expressed as

$$\mathrm{TI} = \mathrm{RF} \times \mathrm{AF} \times \mathrm{MW} \tag{4.4}$$

where TI is the transportation index, RF is the rheology factor and AF is the angle factor.

Knowing the ROP and TI, charts have been developed in Luo et al. [23] and API [20] to determine the MTV for deviated wells.

Poor hole cleaning can have these effects in the drilling operation:

- Slow rate of penetration
- Increased drilling string torque
- High drag
- Risk of stuck pipe
- Difficulties to land the casing because of drag and cuttings accumulation
- Challenges during cementing
- Difficulties in logging

Laboratory test results show that the high enough flow rate can remove cuttings for any fluid, hole size and hole angle. However, higher fluid flow rate will increase the equivalent circulation density of the mud system. This as a result, may cause well fracturing. To avoid this, minimizing pressure losses in the annulus is an important issue for drilling. The pressure losses depend on the fluid velocity, fluid density, and particle concentration. Therefore, a compromise between well stability and cuttings transportation should always exist, where the flow rate must be optimized for each individual well. [24]

Measuring hole cleaning The ASM's can in theory be used for measuring efficiency of hole cleaning. In the event of stuck pipe in the A-10 well, the section being drilled was a 17 $\frac{1}{2}$in borehole with high inclination, which means that the cuttings were likely to settle on the low side. Transport mechanisms are influenced by borehole size and inclination. Solids movement will be achieved through the formation of moving dunes and rolling of cuttings. Hence, the challenge is knowing whether or not the hole is clean. In order to test this, measures can be taken to re-suspend any settled cuttings and make it detectable in the hydrostatic pressure seen on the ASM's. Re-suspension will give an increase in pressure or ECD due to the addition in density of the fluid. According to Coley and Edwards [15], two viable methods have been found to help provide the force needed to re-suspend settled material and make it visible to the pressure sensors; increase rotary speed and circulation of a high weight sweep.

Increasing rotary speed is the simplest of the two options, where raising the RPM above a certain threshold will re-suspend the cuttings. This method has been around for some time, but this is the first time it can be shown in real-time. The reason being that MPT will not work without a certain minimum flow requirements to power downhole tools.

Changes were made to the labels in the WellData system to include the pressure while drilling measurement from the BakerHughes OnTrak tool. Because WellData is a programme for the ASM's, that particular reading is not normally included. The change in denotation can be seen in table 4.3.

Table 4.3: Denotation of pressure sensors in the A-10 well

Component in plot	Represents	Position from drill bit [m]
ASM1	Pressure While Drilling	9.5
ASM2	ASM1	234
ASM3	ASM2	602

Figure 4.4 shows data recorded while drilling the $17\frac{1}{2}$in section, about 23 hours before the pack off event. Pressure while drilling (PWD) is given by the OnTrak tool in the BHA. Its location, inclination and change in ECD in the interval from zero RPM to zero flow rate, is gievn in table 4.4. Values for ASM1 and ASM2 are given in the same table.

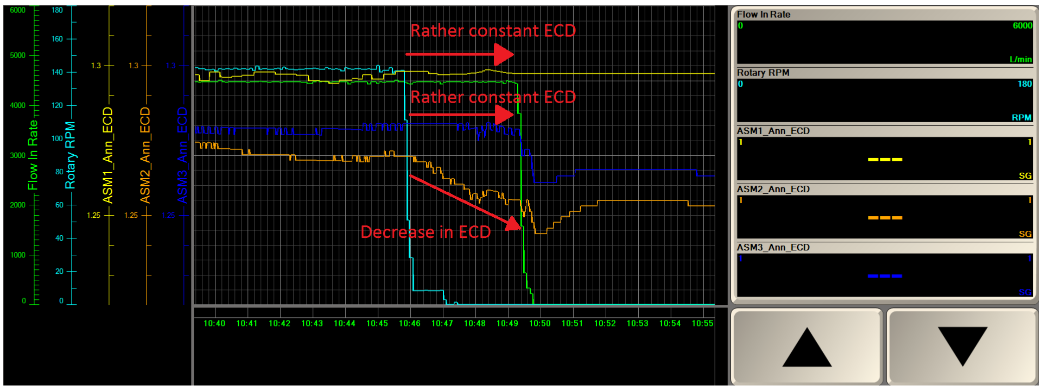


Figure 4.4: Re-suspended / settling cuttings in well A-10 at 2376 m MD

It can clearly be seen that the trend for the ECD is constant, while pumping at a constant rate and having a fairly constant RPM. This situation continues until 10:46. The RPM is then going towards zero, possibly in preparation of picking up a new stand of drill pipe. The RPM is then zero for four minutes, while the pumps are still on. From there it can be seen that the ECD for ASM1 is decreasing, while PWD and ASM2 is still constant. This can be a sign of poor hole cleaning, and that cuttings are accumulating at the shallowest ASM at the end of the slope. It looks like the cuttings are being suspended by the rotation of the pipe, but not transported sufficiently out of the well.

Table 4.4: Location, inclination and changes in ECD of pressure sensor tools, 23 hours before pack-off

Component	Location [m MD]	Inclination [°]	ΔECD [s.g]
PWD	2366	43	0.001
ASM1	2143	37	0.019
ASM2	1773	17	0.002

The same trend is shown in figure 4.5. This figure shows drilling in the $17\frac{1}{2}$in section, about 16 hours before the pack-off event. The location and inclination of the pressure measurement tools are given in table 4.5.

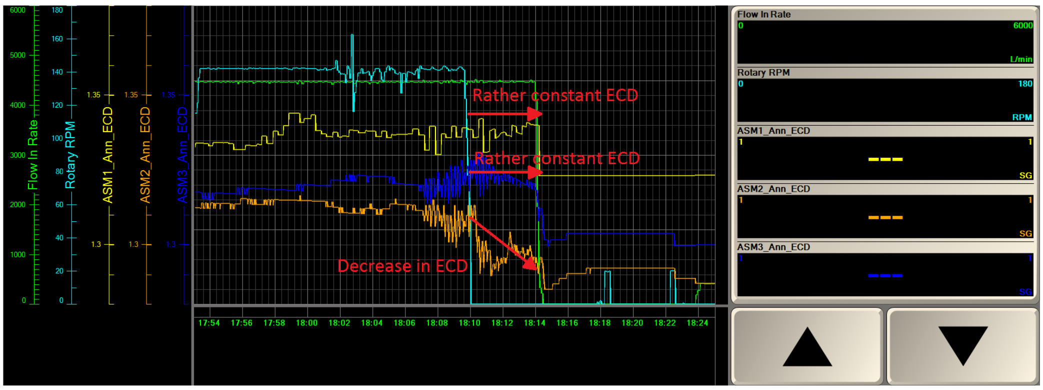


Figure 4.5: Re-suspended / settling cuttings in well A-10 at 2496 m MD

Table 4.5: Location and inclination of pressure sensor tools, 16 hours before pack-off

Component	Location [m MD]	Inclination [°]	ΔECD [s.g]
PWD	2486	46	0.001
ASM1	2261	41	0.024
ASM2	1893	22	0002

Again, the same trend is shown in figure 4.6, 5 hours before pack-off. This time, the decrease in ECD is the largest recorded over the last 20 hours.

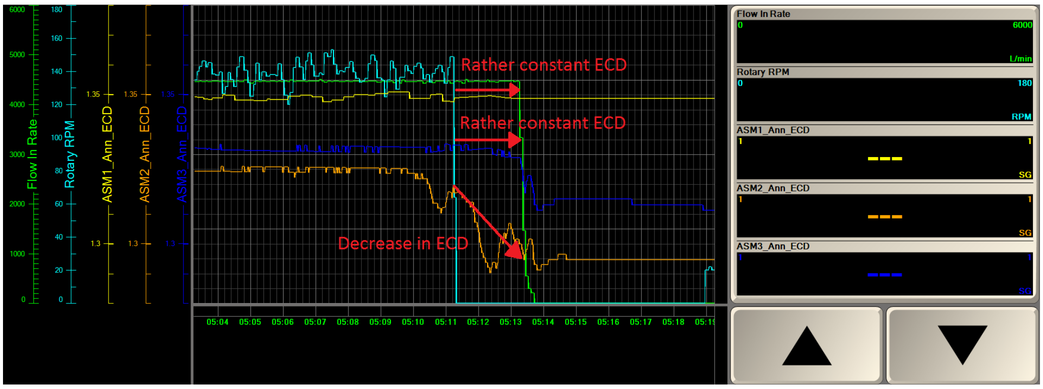


Figure 4.6: Re-suspended / settling cuttings in well A-10 at 2619 m MD

Table 4.6: Location and inclination of pressure sensor tools, 5 hours before pack-off

Component	Location [m MD]	Inclination [°]	ΔECD [s.g]
PWD	2610	47	0.000
ASM1	2385	44	0.030
ASM2	2017	29	0.006

In a smaller diameter hole, rotary speed alone can cause an increase in the frictional pressure seen by a pressure sensor, however in a $17\frac{1}{2}$in hole there is no measurable impact of rotation alone on the annular pressures, as stated by Coley and Edwards [15]. Therefore, the decrease in ECD when decreasing the RPM can be due to temporarily suspended cuttings settling in the well. It is worth noticing that the ECD change in ASM1 is increasing as the time to pack-off gets closer. This might be because more and more cuttings are settling out at ASM1. The increase in inclination will also make it more difficult for cutting transportation, which strengthens the possibility that cuttings settling is actually measured by the pressure sensors.

It should be mentioned that there are very small changes in ECD in figures 4.4 to 4.6. In addition, the values fluctuate a lot, making appropriate selections of values for calculations hard. The question could then be raised if this should only be taken as an example on how to see solid suspension by increase/reduction in RPM, and that maybe the differences in ECD must be more extensive before saying anything with any amount of certainty.

However, BP has used ECD changes of 0.045 [s.g] as a basis for looking at cuttings settling from decrease in RPM with constant flow rate in Coley and Edwards [15].

With the development of downhole sensors such as the ASM pressure sensor it is reasonable to put more emphasize on the analysis of changes in real-time, such as pressures, and prevent borehole incidents on small changes in the parameters shown. From the distribution of inaccuracy in ECD measurements given in figure 4.2, it can be seen that the inaccuracy of the sensor distribution at depths of 2330 m, which is the depth in figure 4.5, has very little impact. For depths of 2330 m this inaccuracy in ECD would be less than 0.001 [s.g].

Figures 4.4 to 4.6 can be seen in contrast to figure 4.7, which is a plot from well A-10 taken 29 hours before the pack off incident. At this point in time the ASM1 is located at 2019 m MD at an angle about 29°, while the ASM2 is located at about 1650 m MD with an inclination of approximately 12°. In this plot, ASM's are not experiencing the same drop in ECD as for the previous example. When the RPM goes to zero, with constant flow rate, the ECD remains rather constant.

Both ASM1 and ASM2 experience a slight increase in ECD, but the change is in 0.010 [s.g], while in figures 4.4 and 4.5 the change in ECD is 0.024 [s.g] and 0.030 [s.g]. Not a very large difference in ECD for sure, but this raises the question yet again on how much emphasis should be put on small changes in measured pressure from the ASM's.

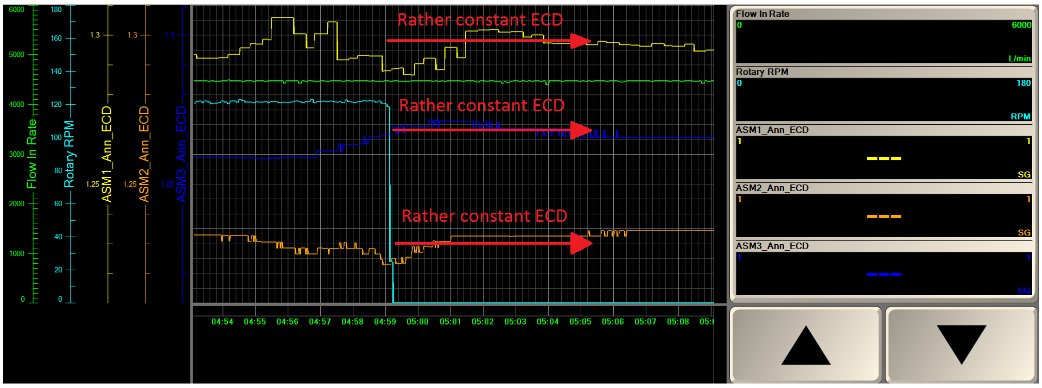


Figure 4.7: Measurements 29 hours before pack-off

Table 4.7: Location and inclination of pressure sensor tools, 29 hours before pack-off

Component	Location [m MD]	Inclination [°]	ΔECD [s.g]
PWD	2244	40	0.010
ASM1	2019	29	0.010
ASM2	1650	12	0.010

Another measure of hole cleaning could be done through hi-vis / weighted sweeps, which can be found in section 4.4.3.

4.4.2 Stuck Pipe

Theory behind stuck pipe Stuck pipe events costs the industry hundreds of millions each year.

The mechanisms behind stuck pipe are usually divided into three main groups:

1. Pack-off/Bridging
    - Pack-off: Cuttings or caved in solids that wraps around the drill string
    - Bridging: Medium to large pieces of hard formations that jams the pipe
2. Differential sticking
3. Wellbore geometry

Behind each of these main mechanisms there are several causes that lead to stuck pipe.

When a stuck pipe situation occurs, one must act quickly and correctly in order to get free. It is important to identify the situation and the mechanisms causing it. In most cases there are trends showing warning signs. The wired drill pipe and along string measurements can be a part of early detection of a stuck pipe event and help identify poor hole cleaning.

In general, cuttings in a borehole will not stay in suspension, instead they drop out of suspension and generally accumulate on the low side of the pipe and can cause a pack-off. The two high potential stuck pipe incident on the Martin Linge field are caused by poor hole cleaning and reactive shale formations. Illusrations of these and how to avoid them, can be seen in figures 4.8 and 4.9 and tables 4.8 and 4.9.

Table 4.8: Pack-off / bridging caused by poor hole cleaning [25]

Avoid Getting Stuck	Free Stuck Pipe
Back-ream and use regular wiper trips	Establish circulation
Maintain correct mud weight	Rotate string for cutting suspension
Monitor cuttings volume change in shakers	Use viscous pills
ROP management	
Recognize increased overpull	
Rotate pipe while circulating	
Use recommended viscous sweeps	

Figure 4.8: Illustration of pack-off caused by poor hole cleaning [26]

Reactive shale is swelling and creating cavings and mud rings around the drill string, as seen in figure 4.9.

Table 4.9: Pack-off / bridging caused by reactive formations [25]

Avoid Getting Stuck	Free Stuck Pipe
Avoid long periods without circulation	Concentrate on working drillstring downwards
Plan regular wiper trips	Establish circulation
Prepare for back-reaming while tripping	Gradually apply freeing force
Recognize changes in mud properties	Increase mud weight
Watch out for surge and swab pressures	

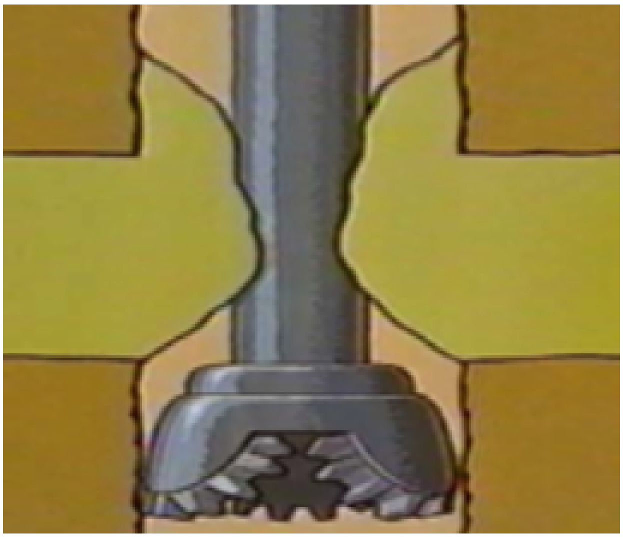


Figure 4.9: Illustration of pack-off caused by reactive formations [26]

Pack-off incident on Martin Linge The formations in the Martin Linge field are very challenging to drill. The reason being that it is hard to achieve good borehole stability in the Hordaland "green clay" formation at the interval of 1657 m to 1794 m TVD RT, and the Upper Frigg formation at about 2638 m TVD is a loss zone with sub-hydrostatic pressure. Sub-hydrostatic pressure meaning pressures below that of a water pressure gradient.

As the pack-off incident occurred in the A-10 well, the denotation on the plot are slightly off. The right denotation is given in table 4.3. An analysis of the ASM data over a 24 hour perspective showed a steady increase in pressure / ECD, increase in RPM, and decrease in ROP, which can be seen in figure 4.10. An increase in RPM variation can also be noted. Having a decreased ROP and increased RPM simultaneously can be a sign of cuttings accumulation and the bit spinning on top of the debris, not being able to get cut into the formation. One of the reasons that these signs where missed could be because the mud weight was increased step-wise. This was probably done as in accordance with the medium-line principle for keeping a stable borehole, and thus an increase in ECD was expected. [27],[28]

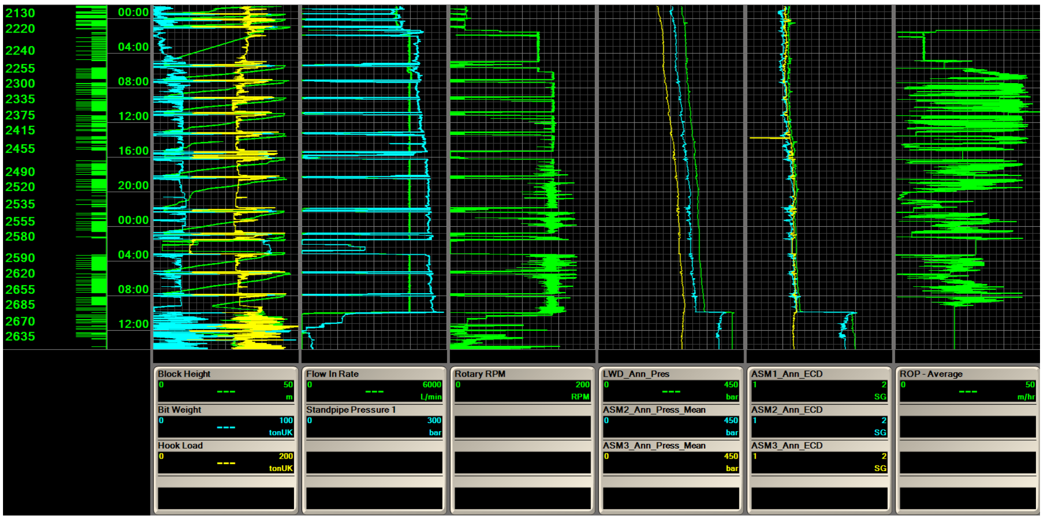


Figure 4.10: Downhole measurements before pack-off

From table 4.10 it can be seen that the 30/4 A-10 well has quite a high inclination. This causes problems with hole cleaning because of cuttings accumulation on the low side. Difficulties in transporting cuttings in the

Table 4.10: The 30/4 A-10 Well Design

Hole size [in]	Casing size [in]	Depth [m TVD RT]	Inclination [°]
36	30	247	0
26	20	1200	9
$17\frac{1}{2}$	$13\frac{5}{8}$	2600	46
$12\frac{1}{4}$	10 (liner)	3750	35
	10 x $10\frac{3}{4}$ (tie-back)	3750	35
$8\frac{1}{2}$	N/A	3920	35

inclined section can cause a landslide of cuttings to the lower part of the inclined section, causing a rapid pack-off. An illustration of this can be seen in figure 4.11. This figure is for illustration only and does not represent the wells on Martin Linge other than that it is deviated.

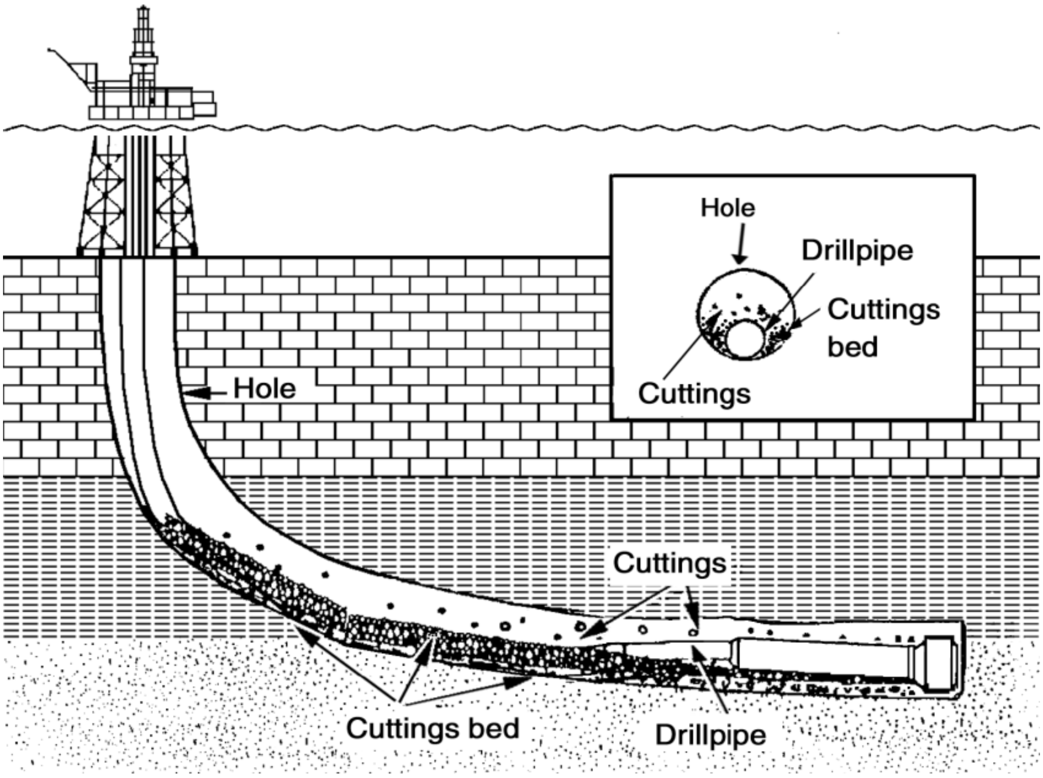


Figure 4.11: Cuttings deposition in a deviated well [24]

After packing off, it is possible to monitor downhole pressure while trying to regain circulation, by the utilization of along string measurements. Since the pumps should be slowly brought back up it is not possible to activate a mud pulse system, but the WDPT can be used to measure if the drill string is still packed off and manage the flow rate accordingly to avoid further losses and aggravation of the loss zone.

After failed trials to get the pipe free, it was decided to shoot off the string. The pack-off point could then be determined by looking at the pressure sensors in the ASM's. ASM1 was located 234 m from the bit and ASM2 was located 602 m from the bit, which corresponds to a measured depth of 2473 m and 2068 m, respectively. When looking at the plot from figure 4.12, it can be seen that the pressures in the PWD and ASM1 are rapidly increasing. The reason being that after the pack-off occurred, fluids are still being pumped into the well. The fluids have no where to go, since the annulus is packed off, and thus the pressure increases. As this pressure increase is only seen in the PWD and ASM1, it can be deduced that ASM2 is located above the pack-off. This is an indicator that the point of stuck pipe is in the range between the first and second ASM, an interval of 401 m.

This saved a lot of time and cost because arrangements could be done instantly to run wireline and shoot off the string, instead of wasting time doing a pull test or wireline run to determine the point of stuck pipe.

In addition, the depth interval of stuck point was seen to be deeper than the unstable shale formation Hordaland "green clay". This is also something that points in the direction of the pack-off being related to hole cleaning.

Deploying wired drill pipe telemetry can thus reduce expenses when unwanted incidents such as these happens and contribute to faster decision making. The same parallels can be taken to failing mud pulse telemetry system, which causes downtime. If WDPT were deployed it would mean a redundancy in telemetry systems, and would thus save downtime.

BP had the same experience when drilling the Kapok 12 well in Trinidad. They saw the same tendency that the sensor beneath the pack-off measured a rapid pressure increase, while the sensors above experienced a pressure decrease. In this specific incident they were able to pin point the location of the pack off to an accuracy of just a few meters. The reason for this was that they had at least three sensors in the hole, for the sake of explanation I will call

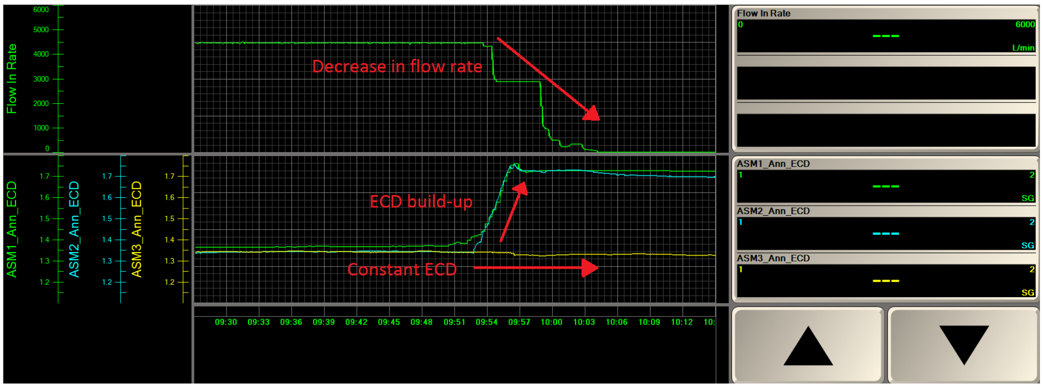


Figure 4.12: Pressure reduction after pack-off in 30/4 A-10 well

the deepest one ASM1, and the shallower ones ASM2 and ASM3. They achieved that amount of accuracy, because the pressure increase was first only seen in ASM1. However, the drilling continued for another 20 ft, and after this distant the string was completely packed off. Now, both ASM1 and ASM2 experienced a pressure increase when pumping. This was interpreted as the ASM2 was first right over the pack-off area, but after drilling the additional feet it was placed under the pack-off. Thus, the location of stuck pipe was pin-pointed. [15]

The probability of pin-pointing the stuck point with this kind of accuracy increases when more MeasurementLinks are placed in the drill string. The possibility of saving wired drill pipe by a more accurate location of stuck point could thus save expenses. This should be taken into consideration when deciding how many MeasurementLinks to deploy.

4.4.3 Sweeps

One of the most important advantages of placing multiple sensors along the drill string is the potential to derive a greater understanding of solids transport behaviour in a real-time.

To help cuttings move through the annulus and out of the well, sweeps are often used. This is just regular drilling mud which has different mud properties compared to the drilling mud. The two properties that are typically adjusted for sweeps are density and viscosity. [29]

Sweeps can be classified into five basic categories:

1. Low-viscosity sweeps, in which an unviscosified base fluid or a fluid having lower viscosity than the base fluid, is used.
2. High-viscosity, in which a volume of drilling fluid is viscosified to a level higher than the base fluid.
3. High-density, in which the density of a volume of drilling fluid is increased to a level higher than the base fluid density.
4. High-density / High-viscosity, in which a volume of drilling fluid is both viscosified and increased in density.
5. Tandem sweeps (two consecutive sweeps) composed of any of the four listed earlier. [30]

Some guidelines for an effective weighted sweep program are:

- The sweep is pumped at regular intervals at the normal circulating rate.
- The pipe rotation speed is ≥60 once the sweep has reached the bit.
- The sweep is allowed to return to the surface with continuous circulation.

The additional buoyancy that weighted sweep provides helps to reduce cuttings-settling tendency while the sweep travels up the annulus. The efficiency of the weighted sweep in dislodging cuttings might cause an increase in ECD, while the annulus becomes loaded. Effects of the ECD can be monitored by the pressure sensors and the pump rate reduced to remain within the acceptable ECD window, while at the same time not allowing any cuttings to settle.

As mentioned, using the pressure sensors it is possible to track weighted sweeps as they travel through the drill string. From these measurements it can be derived if the sweeps are carrying solids or not. The way to do that is to calculate what theoretical effect the weighted sweep will have on the ECD. If this theoretical addition to the ECD matches the measured ECD from the pressure sensors, then there are no packets of cuttings travelling with the sweep and the well is then either clean or the sweep is inefficient. If the measured ECD is larger than the estimated ECD then the sweep is carrying cuttings up the annulus. It will then be possible to track the cuttings travelling up the annulus as shown in figure 4.13. [31]

Using the arrival time at each pressure sensor an estimate for the average hole size can be calculated. The basis for the calculation is that the weighted sweep is travelling with the speed of the pumping rate and the distance between the ASM's measuring the ECD as the sweep passes by is known and the time the sweep takes between each ASM is also known from real time plots. We thus get

$$Q = \frac{A_{\text{annulus}} \times L_{\text{ASM1-ASM2}}}{\Delta t} \tag{4.5}$$

where Q is the pumping rate in $\left[\frac{m^3}{s}\right]$, A_{annulus} is the annulus area in $[m^2]$, $L_{\text{ASM1-ASM2}}$ is the length between the two ASM's measuring the effect given in

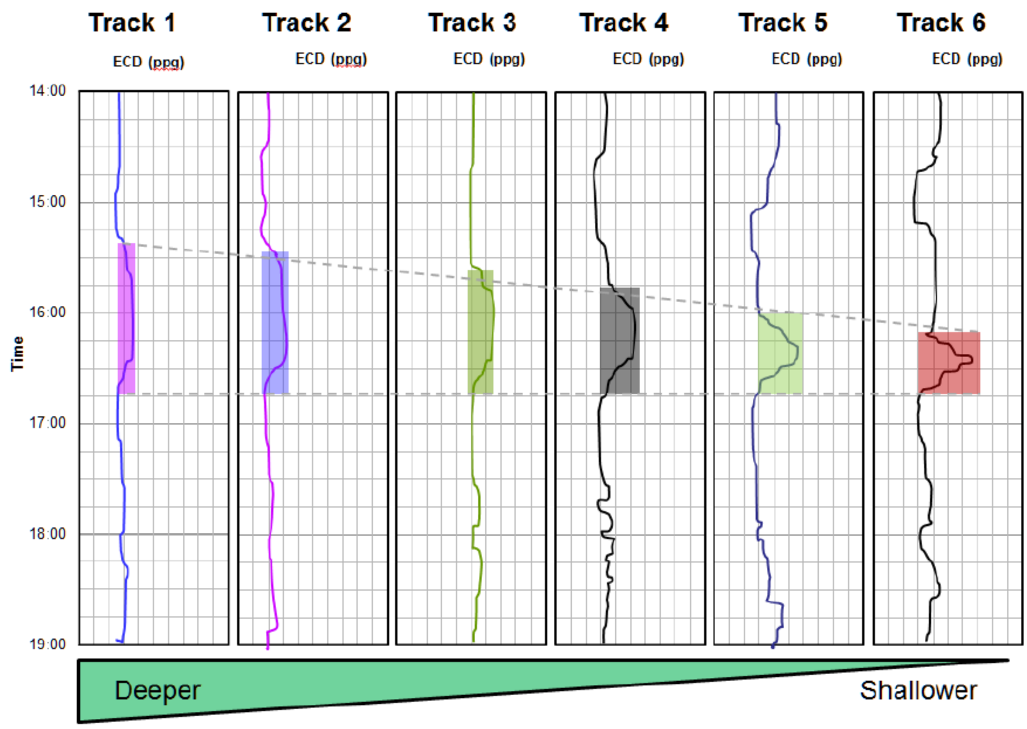


Figure 4.13: Illustration of weighted sweep measurement [31]

[m] and Δt is the time the sweep takes between the two ASM's in question given in [s].

From this the wellbore diameter can be calculated doing the following changes to the equation

$$Q = \frac{\left[\frac{\pi}{4} \times \left(\mathrm{ID}_{\mathrm{well}}^2 - \mathrm{OD}_{\mathrm{DP}}^2\right)\right] \times L_{\mathrm{ASM1\text{-}ASM2}}}{\Delta t} \tag{4.6}$$

where $\mathrm{ID}_{\mathrm{well}}$ is the diameter of the wellbore given in [m], $\mathrm{OD}_{\mathrm{DP}}$ is the outer diameter of the drill pipe given in [m].

Isolating the $\mathrm{ID}_{\mathrm{well}}$ gives the calculated average inner diameter of the well based on the time it takes the sweep to travel from one ASM to the next.

$$\mathrm{ID_{well}} = \sqrt{\frac{4Q\Delta t}{\pi L_{\mathrm{ASM1\text{-}ASM2}}} + \mathrm{OD}_{\mathrm{DP}}^2} \tag{4.7}$$

If poor hole cleaning is experienced, the average borehole diameter will become less than the actual difference between the drill pipe and inner diameter of the wellbore. Thus, if

$$\frac{\mathrm{ID_{well}}\,(\mathrm{calculated})}{\mathrm{ID_{well}}\,(\mathrm{planned})} < 1 \tag{4.8}$$

then there is reason to believe that the well is experiencing poor hole cleaning, and might be packing off. [31]

High viscosity sweeps that provide effective hole cleaning might not be the best option for horizontal wells, because of the flow distribution around eccentric drill pipe. To induce flow, the stress applied to the fluid must exceed that fluid's yield stress. In the narrow annular space created by eccentric drill pipe, it is possible that little or no flow will occur and that the cuttings bed will remain in place. [32]

Weighted sweeps are not run on the Martin Linge field, because of several factors. One being that the sweeps can only be measured on the ASM's in smaller wellbores. For the Martin Linge field, this means that the sweeps would have to be run in a section below the Frigg formation at about 2620 m, which is a formation prone to losses. Thus, a stable pressure profile is preferable.

However, if weighted sweeps were to be used in the section below Frigg, the ECD would have to be monitored closely and adjusting back pressure using managed pressure drilling would be an advantage. The question then is if this is worth the added risk of going on losses.

Monitoring hole cleaning by monitoring the settling or re-suspension of cuttings when decreasing RPM might be a better option for this field, as has been mentioned in section 4.4.1.

4.4.4 Lost Circulation

Loss of circulation is a reoccurring problem in many drilling operations. There are different types of loss situations. A classification is given in table 4.11.

Table 4.11: Types of lost circulation [18]

Type	Description
Seepage loss	Continuous loss of up to $3m^3$ per hour under normal drilling conditions. This indicates ECDs at the threshold of what the formation can withstand.
Partial loss	Continuous loss of more than $3m^3$ per hour under normal drilling conditions. Above threshold of what the formation can withstand.
Total loss	The tolerance limit of the formation is clearly exceeded. No return of flow from annulus. May cause the mud level to decrease in annulus.

When experiencing seepage losses, drilling is often continued. One method to detect the loss zone can be using the ASM pressure measurements.

Methods to detect loss zones [9]:

- Using the borehole resistivity profile
- Borehole image logs

- Borehole temperature profile
- Using the ASM pressure measurements

When the pressure measurements are taken close to the loss zone, that particular ASM will have a larger pressure decrease than the other sensors. The reason being that it will not experience any added pressure from the frictional pressure loss. If the pressures at the different ASM's are plotted against depth as the drilling continuous, a plot like the one in figure 4.14 will occur.

The point where the tangent for the curve turns, will be the point where the loss is located. [33]

Knowing what kind of formation is experiencing loss can be an advantage when it comes to mitigating these losses. Formation integrity tests could be done in that particular zone and the mud weight adjusted thereafter.

For the ASM distribution of Martin Linge with ASM's every 500 m, this effect will be challenging to measure. For that occurrence to be plotted, one would have to drill 234 m with losses. Preferably, 603 m to measure the effect on two ASM's. Thus, for this effect to be measurable, more sensors needs to be placed closer to one another along the string. It would be much easier to detect if the pressure sensors where located between every third stand.

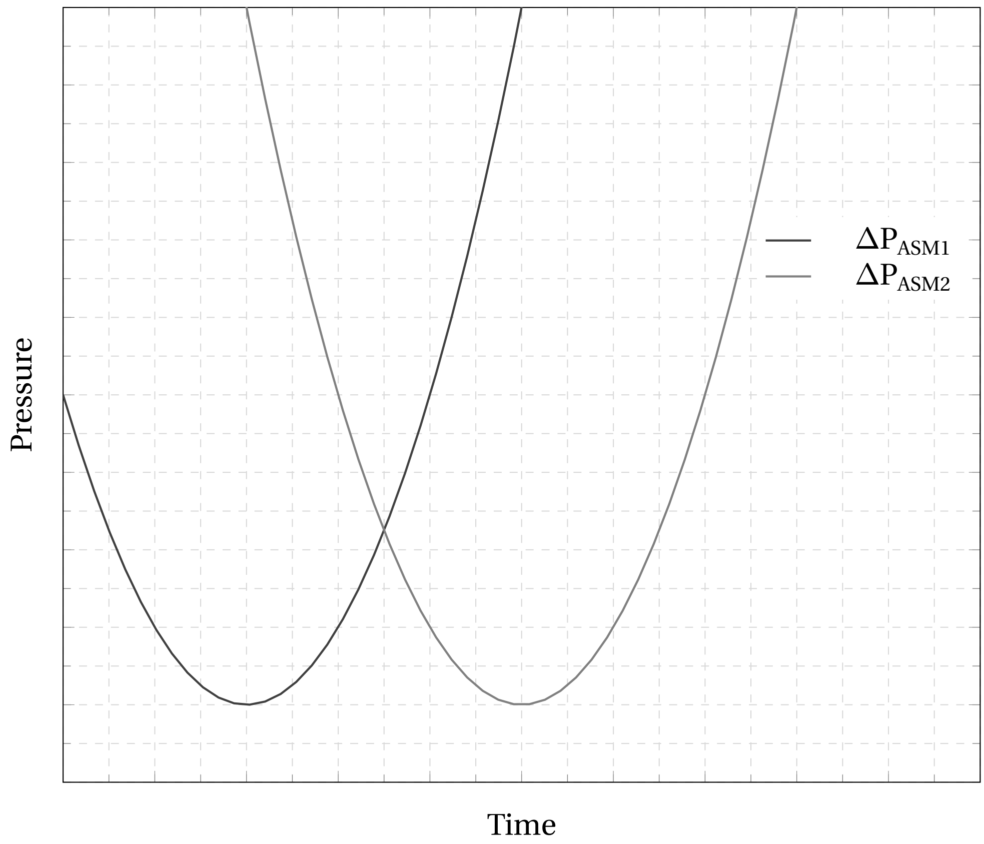


Figure 4.14: Detecting lost circulation

4.4.5 Leak Off Test / Formation Integrity Test

This is the key parameter in stress modelling and borehole integrity evaluation. Typically a leak off test is performed after drilling out the casing shoe to ensure integrity before proceeding with the next hole section. During the test, the well is shut in and fluid is pumped into the wellbore to gradually increase the pressure until formation deformation breakdown or planned testing pressure is reached. In general, when using oil-based mud, the hole is not pressurised until leak-off occurs, this is called a formation integrity test (FIT). A mini-fracturing test is another kind where fluid is injected into the hole, until fracture initiation is observed. These tests are done in order to find the highest mud weight one can have before fracturing the formation and going on losses. This is especially important in formations such as the Hordaland 'green shale' and Frigg formation. At the first instance, it is important to keep a high mud weight to ensure hole stability and secondly, it is important to keep low enough mud weight as to not experience losses.

Although all these tests can be analysed, it is important to use the data consistently, for example not to evaluate a FIT test as a measure of fracture strength. The leak-off pressure is commonly defined as the critical pressure where fracturing initiates. [27]

During a leak off test, continuous pressure measurements are available through the ASM's. This downhole pressure is typically more sensitive to the onset of fracture initiation during a leak off test than the measured surface pressure. Thus, real-time high frequency downhole pressure data can be very useful when conducting a leak off test. [9]

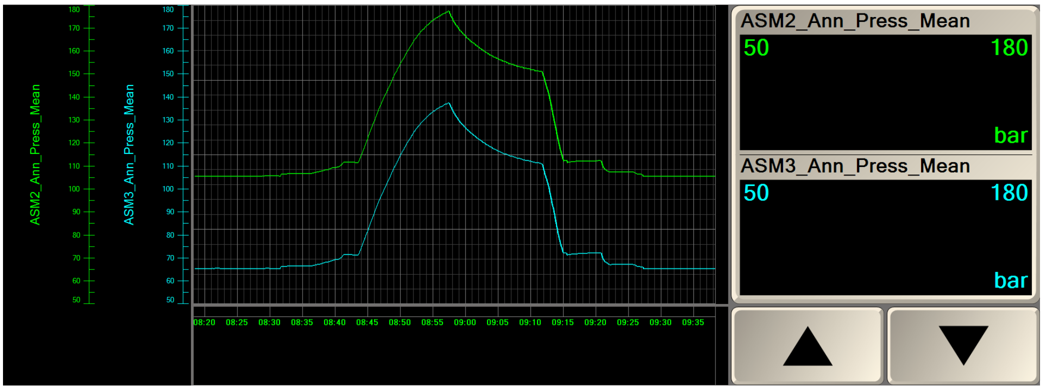


Figure 4.15: Pressure in Well-A10 during leak off testing

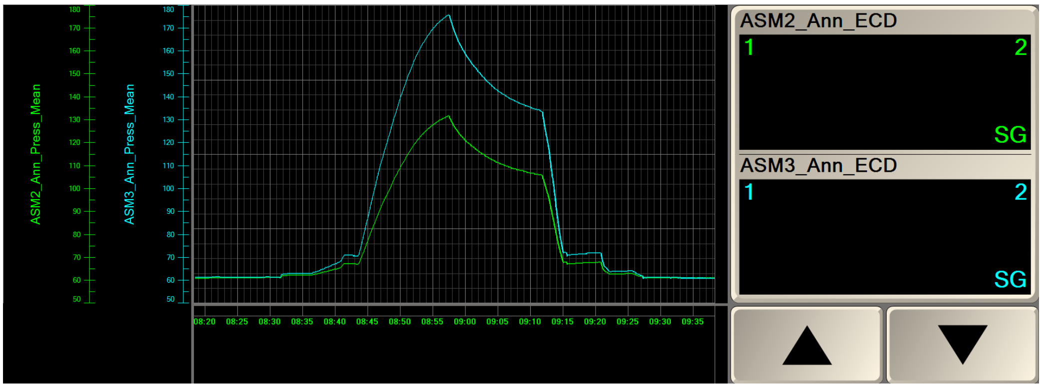


Figure 4.16: ECD in Well-A10 during leak off testing

Figures 4.15 and 4.16 shows plots from ASM1 and ASM2 during the leak off test of well A-10. Notice that in the plots they are assigned numbers 2 and 3. This in accordance with the positions given in table 4.3. The bit is located at 1201 m MD, which corresponds to ASM1 being placed at 969 m MD and ASM2 at 599 m MD. Figures 4.17 and 4.18 is plotted to show the pressure build-up until maximum pressure is reached against the ECD build-up at the same interval. Data is taken from NOV's WellData in figures 4.15 and 4.16.

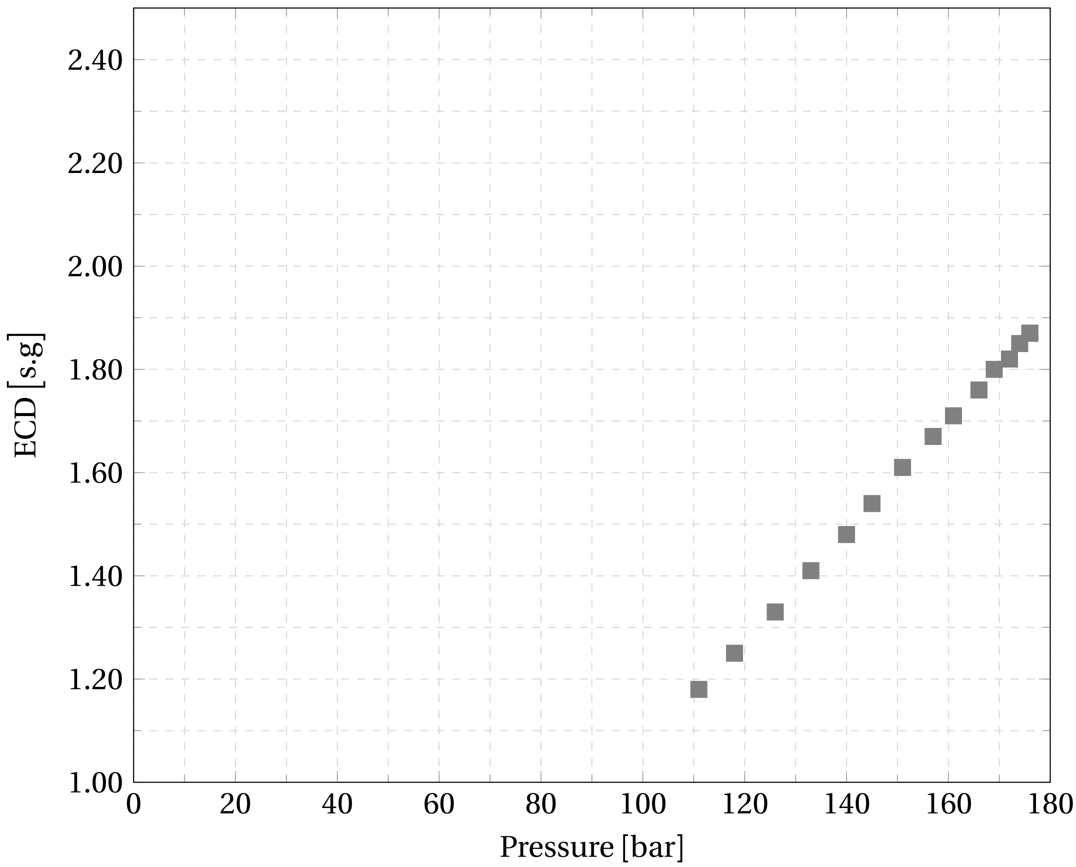


Figure 4.17: ASM1 - Pressure buildup during leak off test in the A-10 well. Pressure plotted against ECD measured at ASM

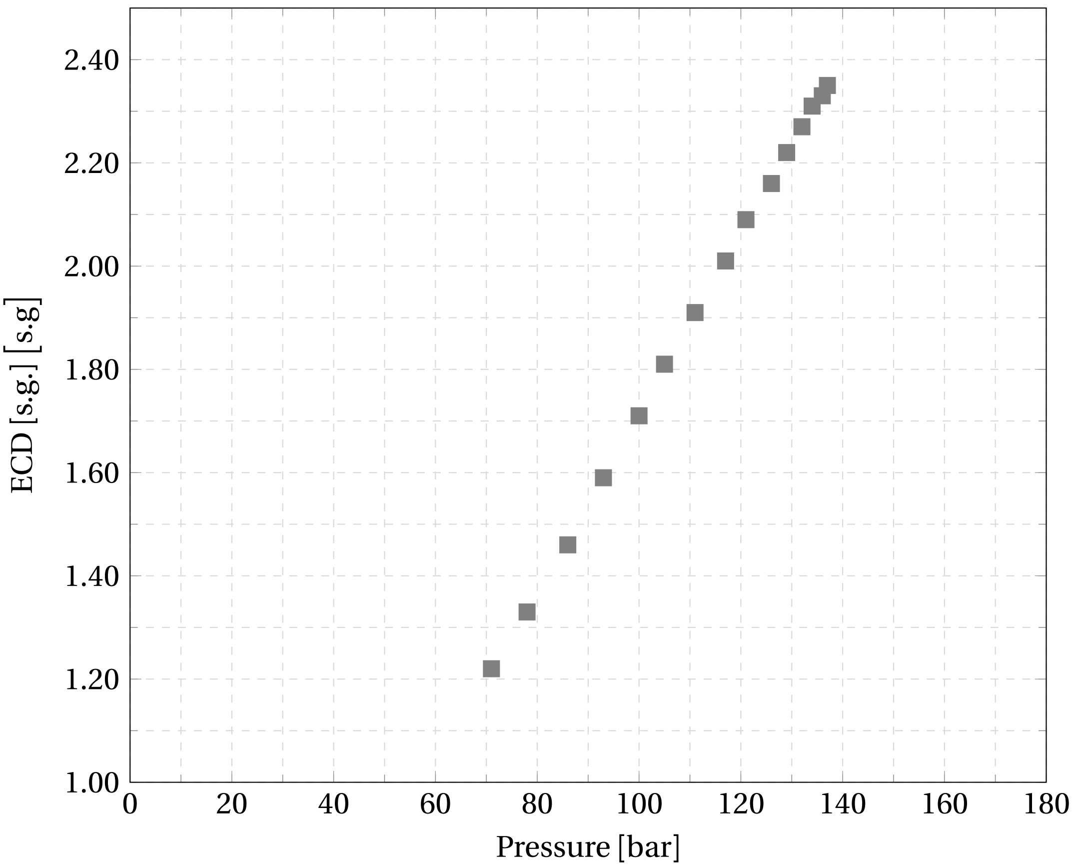


Figure 4.18: ASM2 - Pressure buildup during the leak off test in the A-10 well. Pressure plotted against ECD measured at ASM.

Monitoring of the pressure build-up using MPD makes it possible to increase the pressure faster in smaller increments. The test itself will then take shorter time and can prevent damaging the formation by detecting earlier than expected formation breakdown.

In conclusion, real-time FIT / LOT gives more confidence in the numbers and gives maximum pressure the shoe can withstand. Possibly allowing to settle the next casing deeper. This can be achieved because of:

- Acquisition of data in real-time, making it possible to stop the test at the onset of formation failure, avoiding unnecessary over pressuring
- Eliminates the need for additional circulation to condition mud prior to LOT / FIT
- Increase accuracy of the test, which in turn
  - allows more precise casing depth determination
  - improves drilling safety
  - potentially reduce the number of casing strings

4.4.6 Interpretation of Data

When analysing data, it is a big advantage to have something to compare the measured data against. ECD fingerprinting is a technique that has been around for a long time, but seldom utilized to its full potential. It is an empirical method that can be used to measure the impact of changes in flow rate and rotary speed on the frictional back pressure. In general, friction losses are only significant in smaller diameter sections, 14 in and lower. In addition, fingerprinting has a maximum section length over which it is useful. When applied correctly ECD fingerprinting can provide an alternative to hydraulic modelling techniques, and has the advantage that the baseline that it generates is calibrated to the specific sensors and wellbore conditions of the section in which it is performed. [15]

Fingerprinting is performed in a cased hole prior to drilling out the shoe. The RPM and flow rate is then tested for predetermined values. A description of the procedure could look something like the following:

1. Verify and record the bit depth and pressure-while-drilling depths both in MD and TVD.
2. Adjust pumps and rotary speed to wanted initial test rates and circulate for about five minutes to allow wellbore pressure to settle.
3. Monitor and record ECD.
4. Keep pump rate at the current level and increase rotational speed to the next point, then wait for the wellbore pressure to settle.
5. Monitor and record ECD, bottom hole temperature, mud weight in and mud weight out.
6. Repeat items 4 and 5 until all rotary speeds are tested for the fixed flow rate.
7. Adjust pumps to next planned increase in flow rate and repeat procedure from items 4 and 6.
8. Adjust flow rate and rotary speed to zero and allow pressure to settle for five minutes to obtain static.
9. End ECD fingerprinting exercise.

Once these data have been gathered, they can be used for predicting what the annular pressure should be in a good hole cleaning environment. This can be done by calculating a frictional pressure drop per unit length in the well for each of the combinations of rotary speed and flow rates tested. This number can then be used to estimate a value for frictional pressure drop for any combination of flow rate and rotary speed within the bounds tested. This value can then be multiplied with the depth of the pressure sensor to get the estimated pressure / ECD. A measured value that differs from the estimated value could be a sign of poor hole cleaning or that some other scenario is affecting the pressure downhole, such as influx, loss zones, etc.

The applicability of the fingerprinting method described can be limited if the inner diameter from top to bottom has different sizes. If the inner diameter is approximately the same through the whole well, the frictional pressure drop will be about equal at every depth, thus the method of frictional pressure drop per unit length is an accurate model. For different inner diameters, however, the value of frictional pressure drop will vary with the different diameter sizes. This is due to the fact that smaller diameter pipes will experience a larger frictional pressure drop than larger diameter pipes. Frictional pressure drops during drilling in a $17\frac{1}{2}$in hole will be almost negligible, while the frictional pressure drop in a $8\frac{1}{2}$in hole will be substantial. [15]

Frictional pressure drop can be calculated from the Darcy-Weisbach equation [24]

$$\Delta P_f = f_D \times \frac{L}{D} \times \frac{\rho u^2}{2} \tag{4.9}$$

where ΔP_f is the frictional pressure loss given in [Pa], f_D is the dimensionless Darcy Friction Factor, $\frac{L}{D}$ is the dimensionless ratio of length to inner diameter of pipe, ρ is the density of the fluid given in $\left[\frac{kg}{m^3}\right]$ and u is the mean flow velocity given in $\left[\frac{m}{s^2}\right]$.

To find f_D, the Haaland equation can be used [34]

$$\frac{1}{\sqrt{f_D}} = -1.8 \times \log\left[\left(\frac{\varepsilon}{3.7}\right)^{1.11} + \frac{6.9}{Re}\right] \tag{4.10}$$

where ε is the surface roughness coefficient and Re is the dimensionless Reynolds Number.

The surface roughness coefficient can be found from the following

$$\varepsilon = \frac{k}{D} \tag{4.11}$$

where k is the surface roughness and D is the inner diameter given in [m].

The Darcy Friction Factor, f_D, can be found from a Moore Diagram, and thus the frictional pressure loss can be calculated for different inner diameter sections.

In conclusion, it could be beneficial if the values from the ECD fingerprinting could be compared with the ASM pressure readings in real-time to see if the pressure readings are as expected.

When comparing the estimated ECD values and actual values from the ASM's, it is important that the sensors are evenly distributed along the drill string. If placing sensors only in the open hole section, hole cleaning can not be tracked up the annulus and does not provide an accurate picture of the hole cleaning process.

Analysis of data can be a very challenging task, especially when dealing with the data in real-time and having a very narrow time-range to notify personnel and take action before things go wrong. It can therefore be useful to establish guidelines when dealing with data analysis. The guidelines could be used both to detect and identify causes of variations in the data, and help with the approach that should be taken when a possible wellbore incident is detected.

An example could be made from the situation described in section 4.4.1:

Data Interpretation Guideline

Situation of Analysis

- Decrease in RPM
- Flow rate remains constant

Observed Pressure / ECD Behaviour

- ECD drop observed on one or more sensors
- ECD drop begins and ends at the same time on all sensors

Probable Cause

- Most likely poor hole cleaning, with cuttings accumulation at the location of pressure sensor

Potential Outcome

- Pack-off, resulting in stuck pipe incident

Potential Misinterpretation

- If these observations are made in smaller diameter holes, the RPM itself could be a cause of pressure decrease. This because of an addition to the frictional pressure loss

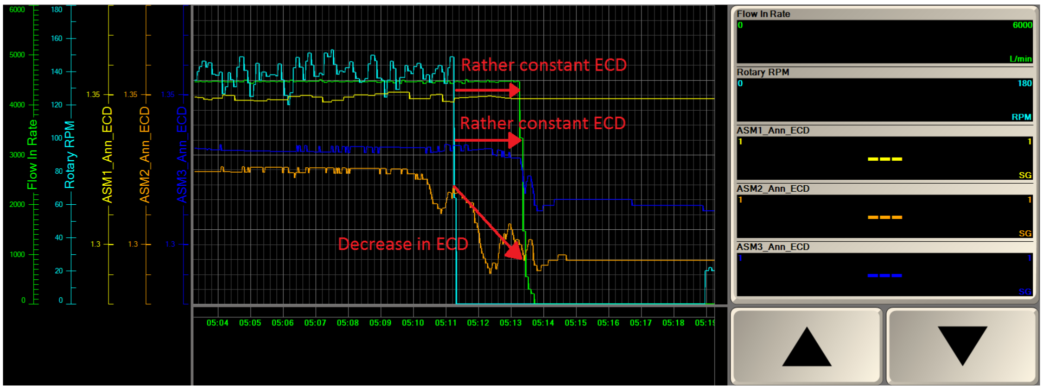


Figure 4.19: Data analysis, guideline illustration

Early detection and recognition of wellbore incidents while drilling are generally challenging to interpret based on sensor readings. In addition it is demanding to monitor an ever increasing set of drilling parameters. A focus could instead be put in developing models and systems to detect wellbore incidents before they can be noticed by individuals. Model-based diagnostic systems are already being developed and an example of such a system can be found in Willensrud et al. [35].

5 Discussion

5.1 Reliability

The uptime rate of 91 % on Martin linge, is comparable to that recorded by NOV late 2011, seen in figure 3.6. From discussions with other operating companies, this uptime value is better than what previously experienced on the Norwegian continental shelf.

However, the uptime experienced at the beginning of the project was much lower. The first five months, the average uptime was at 64.2 %. This shows how good the uptime was the following 4 months, to achieve an average of 91 %. It is likely that future uptime rates on Martin Linge will be higher than that initially recorded. With a new rig, new crew and new wired drill pipe, there was reason to expect lower reliability values as according to the bath-tub curve principle.

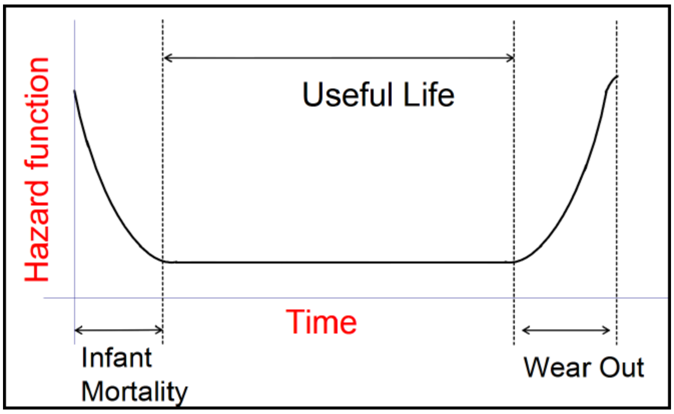


Figure 5.1: Reliability performance of components [36]

In addition, the next generation of wired drill pipe coils are coming up, and are soon to be used on the Norwegian continental shelf. These coils are recessed in the pin end of the drill pipe, and elevated in the box end. This should make the reliability values go up, as it protects the coil from mechanical damage. The increased clearance between coil and groove, also allows for connection deformation, as a remedy for the high numbers of over-torqued connection failures.

5.1.1 Standardization

As the situation is now, nearly all equipment involved in the wired drill pipe telemetry operation must be customized. There are very few, or none, wired items that are available "off the shelf". This makes both the planning and operations more demanding. In addition, the system becomes more prone to failures. If a piece of equipment fails, it might not be easy to get a spare. This would increase the reliability.

5.2 Data analysis

The data analysis presented in this paper are both done with respect to examples found on the Martin Linge wells, but also some other theoretical analysis that has not been found examples of, as of yet. Because of the lay out of the along string measurements in the wired drill pipe, and the number of ASM's, some analysis proved to be very challenging. One example being loss zone localization. The distance between the ASM's needs to be close enough that when drilling with seepage losses, one or more of the pressure sensors will cross that particular formation.

However, analysis that has been successfully done has saved a lot of cost, and possibly an entire well section. When measuring the ECD along the wellbore, flow rate optimization resulted in avoiding fracture of the formation. When a stuck pipe incident occurred, stuck point interval was measured.

In addition, the analysis of cuttings settling done in section 4.4.1 could have saved the drill pipe from being packed off, if done in real-time. This would have prevented the large amount of cost associated with the stuck pipe incident.

In the future, data analysis will have to be improved to be able to detect such incidents in real-time. For that to happen, a software should be developed to recognize changes in parameters that are associated with different downhole incidents.

5.2.1 Tool Development

The downhole tools currently available are developed with respect to the mud pulse telemetry. As a result, the high band width of the pipe can not be used at maximum capacity. Instead of continuously measuring, the tools only take measurements every ten seconds in order to avoid filling up the memory of the measurement tools.

New tools must be developed that are customized to the wired drill pipe, to take full advantage of the bandwidth available.

The along string measurements currently available for the MeasurementLinks are somewhat limited, as for Martin Linge they only measure temperature and pressure. In the future, an increased variety of sensors available will increase the advantages of using WDPT. If measurements like caliper and cement bond log were available, this could in the end replace an entire wireline run. This will not only help understanding the behaviour of wellbores but also save a lot of rig time and reduce the cost of drilling wells.

5.3 Cost

When it comes to cost saving by wired drill pipe telemetry there are different parts to consider. Firstly, time spent on telemetry has been analysed in section 3.3 and a substantial amount of time saved per 1000 m drilled has been found. What has not been included is the cost saved by locating the point of stuck pipe and avoiding wellbore incidents. These are things that are harder to put numbers on, but needs to be done to get the full view of cost saved by deploying wired drill pipe telemetry.

The cost of implementing WDPT, and all the operational costs associate with it, must then be subtracted from the cost saved. This will then produce the actual value of the wired drill pipe telemetry system.

5.4 Future Studies

From what has been revealed in this thesis, the following topics should be studied to take the wired drill pipe telemetry applications to the next level.

5.4.1 Automation

For the past several years, automated drilling has shown promise to deliver major improvements in drilling performance. However, technological obstacles and the global reduction in oil prices has affected its progress and commercialization.

The wired drill pipe would be the nerve system for an automated drilling system. High band width telemetry is required to be able to transmit the necessary amount of data from downhole measurements in real-time.

By enabling for automated drilling, a substantial reduction in drilling time could be accomplished. In 2014, ConocoPhillips and NOV completed a pilot programme in Texas to test a new automated system, which reduced drilling time with more than 40%. This indicates that the future of drilling lies in automation. This will enable cost efficient wells, drilled in a safe manner. [37]

5.4.2 Data Interpretation Models

To use the full potential of the along string measurements, data interpretation software needs to be made. Future studies should revolve around how to make systems and algorithms analyse the downhole data, run diagnostics, find the related downhole issue and proposes a remedy. These algorithms could be based upon section 4.4, and developed further into including several possible scenarios. Software for drilling optimization exists already, but with the new measurements available from along string measurements, these needs to be included in the algorithms to give a greater understanding of downhole conditions.

6 Results and Conclusion

From the studies done on Martin Linge, it seems like operations with wired drill pipe telemetry can finally be done successfully on the Norwegian Continental Shelf. With an average of 91% wired drill pipe telemetry uptime in 9 months, the system shows quite good reliability values.

Hence, reliability is increasing to rates that are proving acceptable, with a back up system in the mud pulse telemetry system. However, the reliability must be a main focus for the future, with the goal being a hundred percent uptime. As shown in section 3.2, improvements to the wired drill pipe network system are being made continuously. As a result the reliability is showing a positive trend, which is encouraging for future reliability values. With the second generation wired drill pipe coming up, with several improvements of the design, the reliability should be further improved.

The along string measurements are currently a feature that makes for continuous measurements along the wellbore and enables fingerprinting enhancements, possible early determination of pack-off's, hole cleaning measurements and leak off test enhancements, amongst others. In the future, more sensors associated with the MeasurementLinks should be developed and thus in the end, replacing wireline runs. This will be a revolution in wellbore technologies, reducing time per well and improve the quality of the boreholes drilled. This can be done by introducing more surveillance by for example using calliper logs while drilling.

When it comes to the analysis of the measurements done by the

MeasurementLinks, there are different possible steps to make it more efficient. For the analysis to be done in real-time, extensive practice and training is needed. There are many parameters that can be looked at, but guidelines and checklists needs to established, such as in section 4.4.6. However, it is very difficult to do data analysis manually, in real-time. This leads to the second possible way to go. Softwares and systems might be the best way for early pack-off detection and other various downhole incident detections. Algorithms need to be developed to model the different scenarios and the various change in parameters. If a system like that where to be developed, it would make for better quality boreholes and optimization of drilling operations. The warnings could then come from the system, and decisions to make changes or keep drilling could be made.

Even though wired drill pipe has a high initial investment cost, it can save a lot of time, which means saved rig time and money. On Martin Linge, a reduction in telemetry time of 5.87 [hours/1000m drilled] was realized. This is substantial compared to the offset wells. In case of tool failure, increased diagnostics can be run, and well considered decisions can be made to either pull the string or continue drilling. Every BHA trip that is saved is a lot of cost saved, with the current high rig rates.

In conclusion, the feats achieved with wired drill pipe on the Martin Linge field are substantial. If the reliability of the wired drill pipe telemetry system gets close to a hundred percent, it will for certain be the new standard in drill pipe technology in the industry.

Appendix

A ASM Tool

BlackStream™ ASM Tool

Specification Sheet

Along-String Measurements: collar-based Dynamics Measurement Tool.

HARDWARE | **SENSORS**

Specifications 5″ Drill Pipe

Tool	Specifications
OD	6.625″
ID	3.25″
Length	53″ shoulder to shoulder
Pressure Rating	25,000psi
Material	High-Strength Steel Alloy
Connection Type	GPDS50 pin x box
Rated Temperature	150°C
Battery Life	Up to 1,000hrs
Reporting Period	Every 2 Seconds

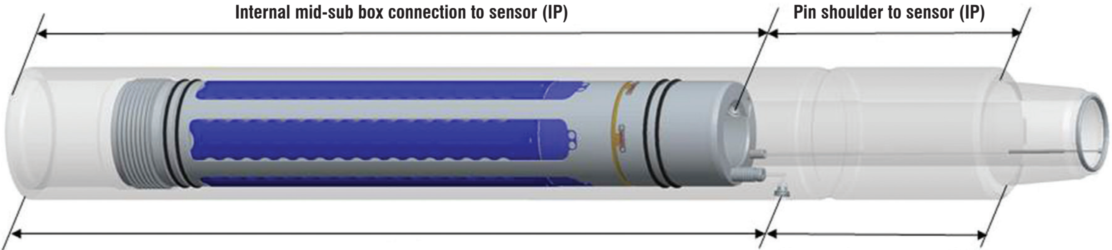
Sensors	Specifications
Radial (Lateral) Acceleration (x2)	±50g (.01g resolution)
Tangential Acceleration (x2)	±50g (.01g resolution)
Axial Acceleration (x1)	±35g (.001g resolution)
RPM (x1) (Gyro)	0 to 1,000RPM
Pressure (Internal/External)	0 – 25,000psi (~ 0.01% FS)
Temperature	-40° to 150°C

Specifications 5½″ - 5⅞″ Drill Pipe

Tools	Specifications
OD	7″
ID	3.50″
Length	51.75″ shoulder to shoulder
Pressure Rating	25,000psi
Material	High-strength steel alloy
Connection Type	XT57 pin x box
Rated Temperature	150°C
Battery Life	Up to 1,000hrs
Reporting Period	Every 2 seconds

Data Acquisition	Specifications
Background Sampling Rate	256Hz
Data Acquisition / Power Enable	Cycled through the network
Storage (buffer size)	256 bytes
Number of channels	25
Statistics reported	Minimum/average/maximum values for radial acceleration, tangential acceleration, internal pressure, external pressure, rotation, and the mean and standard deviation on azimuthal radial acceleration, and tangential acceleration.
Reporting Time	Every 2 seconds

Pressure sensors are located as follows	5” *BlackStream* ASM Tool	5⅞” *BlackStream* ASM Tool
From the pin shoulder (Internal Pressure-IP) / or from the internal mid-sub box connection	15.25” / 37.83”	13.695” / 38.055”
From the pin shoulder (Annular Pressure-AP) / or from the internal mid-sub box connection	11.83” / 38.25”	10.377” / 41.38”



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D392005519-MKT-001 Rev.01

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