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MASTER THESIS

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ABSTRACT

Oil and gas companies target to carry out drilling and other well operations in a safe and cost-effective manner with focus on the long-term integrity of the wells. Well operations become more challenging in environments such as depleted formations, extended reach horizontal well and deep-waters. In the recent years, the industry developed new technologies and methods to manage and enhance the efficiency of drilling operations in these environments. However, there are still challenges faced by the industry. For this, the industry developed a wiredpipe (WDP) technology to improve the data quality, quantity as well as speed of transfer. As a result, WDP technology improved the drilling activity significantly. The recently approved plan for development and operation (PDO) has granted Snorre field expansion project (SEP) to Equinor ASA. The field being depleted has planned equal number of injection and production wells, which could have both the pore pressure and formation stress altered. In general, one may expect operational challenges in the field.

A total of eight field case studies were conducted on the application of WDP technologies. Based on the lessons learnt, problems associated with the conventional method and the corresponding possible WDP solutions to be utilized in SEP or future field development activities are proposed.

Results from the field case study shows that the valued contributions of wiredpipe are faster drilling rate, time-efficient rig operations, risk reduction, enhanced well placement/quality and reduction in mud losses. Results from the possible alterative WDP solution for SEP are with regards to tripping, cementing, wellbore cleanout, perforation, completion and side-tracking operations. The author believes that integrating the solutions will enhance SEP operations, reduce non-productive time and therefore will be cost-effective.

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d	Diameter of the pipe
D	Hydraulic flow size
f	Friction Factor
L	Length of the Flow Line
k	Surface Roughness
u_m	Average Velocity
μ	Coefficient of friction
ε	Surface Roughness Coefficient

LIST OF ABBREVIATIONS

AOS	Automation Operating System
ASM	Along String Measurement
BHA	Bottom Hole Assembly
BHP	Bottom Hole Pressure
BPS	Bits Per Second
CBU	Circulating Bottoms-up
DOP	Detailed Operational Procedure
EMS	Enhanced Measurement System
ECD	Equivalent Circulating Density
EMW	Equivalent Mud Weight
FIT	Formation Integrity Test
ID	Inner Diameter
IBOP	Inner Blow Out Preventer
LCM	Lost Circulation Material
LOT	Leak Off Test
LWD	Logging While Drilling
MD	Measured Depth
MW	Mud Weight
MPD	Managed Pressure Drilling
MPT	Mud Pulse Telemetry
MTBF	Mean Time Before Failure

MWD	Measurement While Drilling
MW	Static Mud Weight
NCS	Norwegian Continental Shelf
NOV	National Oilwell Varco
NPT	Non-Productive Time
OD	Outer Diameter
POOH	Pulling Out of Hole
RIH	Run in Hole
ROP	Rate of Penetration
RPM	Rotations Per Minute
RSS	Rotary Steerable System
SEP	Snorre Expansion Project
TD	Target Depth
TDS	Top Drive Swivel
TVD	True Vertical Depth
UBO	Underbalanced Operation
WDP	Wired Drill Pipe
WBCO	Wellbore Cleanout
WDPT	Wired Drill Pipe Telemetry
XLOT	Extended Leak Off Test

1 INTRODUCTION

Oil and gas industries are continuously developing novel technologies. The new digital technologies have revealed improving drilling efficiency and indicates a potential to solve the conventional well operation challenges. Among these, Wired Drill Pipe is an exciting innovation for wellsite activities.((PWC),2017)

This thesis presents the performance of wired drill pipe technology in oil and gas fields around the globe. Equinor ASA have started using WDP in recent years in drilling operations. However, Equinor ASA is more focused to understand the potential/ alternative applications of WDP in other well operations. (ASA, 2018b; Jacobs, 2019).This led to the decision to use WDP in Snorre Expansion Project in near future. For this, the thesis addresses the problems associated with rigsite operations using conventional drill pipe and the possible WDP solutions for Equinor ASA assets will be presented.(Project), 2019)

1.1 Background

Despite technological development in exploration and production sectors, the oil gas industry is still facing several challenges. Among others, drilling operations in areas such as ultra-deep water, HPHT and gas hydrate reservoirs or depleted reservoirs can be mentioned as examples. (Reservoirs, 2019)

For instance, in deep-water ERD wells, the drilling window is narrow. Hence, drilling with conventional methods results in several problems such as high torque and drag, well collapse, well fracturing, equipment failure, and may lead to well control situations. The problems can be minimized by implementation of real time monitoring system that could provide early indications of downhole instabilities. Based on it, appropriate remedial actions could be implemented. (Lesso, Laastad, Newton, & Olberg, 2008)

Drilling related problems in general increases the nonproductive time (NPT). Figure 1.1 presents a case study conducted on 5900 wells in Europe. The data were obtained from 47 operators exploring in NCS and UK shelf. The figure 1.1 shows that despite the development in drilling technology as seen from increased drilling depth per day, still the non-productive time records 25-30%(Hovda, Wolter, Kaasa, & Olberg, 2008). This cost the oil and gas industry unnecessary expenditure.

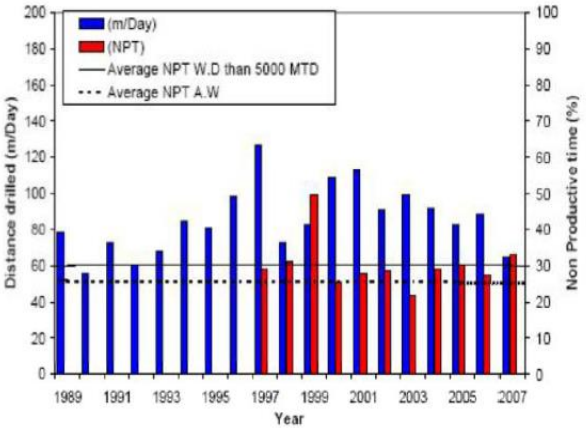

Figure 1.1. Drilling rate and nonproductive time case study.(Hovda et al., 2008)

As the water depth increase the drilling related operations become more challenging. Figure 1.2 shows a case study of NPT in the Gulf of Mexico. The pie chart displays the nonproductive time by type. During the 1993-2003 period, gas well shows that the total downtime accounts about 40%. Among these, the kick and lost circulation recorded a higher rate(Sweatman, 2006) Issues related to wellbore instabilities annually cost the industry about US$26 billion (DODSON et al., 2004). The application of real-time data could provide a quick remedial action to the reduction of NPT. This can be accomplished by employing high-quality real-time data transfer and logging while drilling or other well operations.

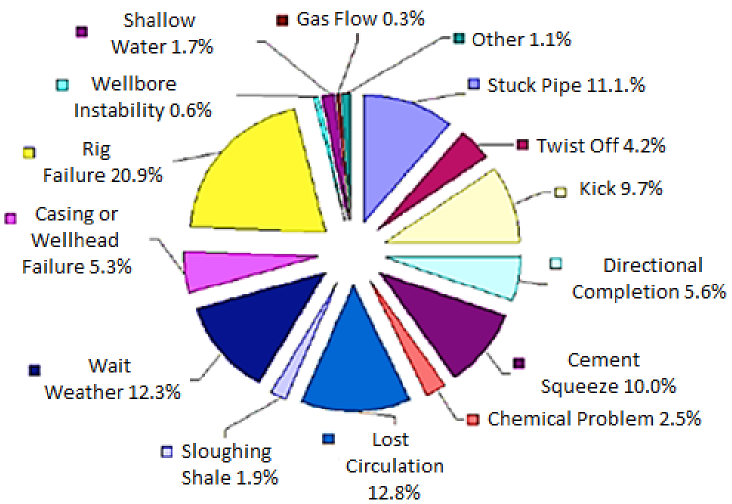

Figure 1.2. Drilling down time in deep-water field > 15 000 ft (DODSON, DODSON, & SCHMIDT, 2004)

Now days, the application of real-time data is widely used in the industry. Well activities in the offshore can be monitored live at onshore real-time operation centers. By doing so, on shore drilling center engineers can support offshore drillers by following logged drilling data. For this, the quality of data transfer is important. Properly acquired data minimize wrong interpretation and hence one can rely on the decision that are made. Correct utilization of real time data benefits to reduced NPT, improve HSE related issues, and improve productivity/operational performance.

Offshore drilling industry is opting to wired drillpipe telemetry for well operations. In recent times, rigs are being replaced with WDPT due to the higher efficiency of this technology in receiving coherent downhole data which helps in drilling complex trajectories resulting in better field development.

The application of WDPT is proven in several regions in the world including in NCS for instance in Martin Linge field. However, up to this proposed author’s knowledge, the application of WDPT is not widely documented in lower completions and other well operations.

Industry faces large number of issues as discussed below with the usage of conventional mud pulse telemetry. A huge amount of critical data is being collected downhole by the complex MWD and LWD tools. But the ground reality that these data are transferred at rate of 4 bits/sec in mud. Although the discussion is about real time operation, yet the data is not received real time from the mud column (Foster & Macmillan, 2018) (Lesso et al., 2008)A smarter and faster way to use the data collected by the downhole tools to inform decision making in real time is an urgent requirement. (Stephen T. Edwards et al., 2013)

1. ***Limited Downhole communication/ Data Transmission:***

The sensors might not be able to recognize the pressure fluctuations during conventional mud pulse telemetry when different density fluids are used in well. E.g. Lost circulation is an event when lower density mud should be pumped into the well to control the losses. Since different density mud get mixed, the ability to have a sound communication through the column of fluid is challenging. It is vital to get correct data from the bottom tools in such scenario. Communication with the tools downhole is lost when the pumps are off(Solem, 2015; Wilson, 2013).

2. *Limited Data Visibility:*

Resolution of the data obtained from the downhole tools is important for the geologist to estimate the oil recovery. To make the right decision regarding wellbore stability, drillers require precise data quality. For more than past 10 years or so, wellbore instability is diagnosed by using azimuthal density images. But most of this activity is performed after the operation when the data is downloaded from the BHA at surface. Due to the restriction of MPT, while drilling LWD density tools cannot transmit data to the surface. The low-resolution image obtained by MPT generally cannot help in interpreting wellbore stability issues. (Fosse, 2015)

3. *Limited Drilling Performance:*

Achieving high ROP as possible without compromising the safety of the well operations and stability of the well is the focus for operators across the globe. Conventional telemetry systems can introduce ROP limits because of slow data transfer speeds such as LWD data density, directional control or ECD management. The driller can adjust the parameters as required to control the ROP, only if accurate real time data is received at the drillers console. Since MPT has its limitation, the performance of drilling operation could be affected. (Solem, 2015)

4. *Insufficient Downhole Data:*

In exploration or production well, acquiring data is one of the most important aspect for decision making. Due to the bandwidth restriction in MPT most of the readings from the density tools are not transmitted to the surface(Wilson, 2013). Although in exploration, well sampling is prioritized, while in drilling a production well geo-steering/ well placement forms the major concern. In both cases, data acquiring plays a major role and conventional methods lack to provide relevant downhole information. MPT transmission is limited with respect to the transfer of data. In ERD wells and deep-water drilling operations, the signal degrades at higher depths. Also, data can be collected only at the BHA and not along the string in MPT. Hence, it is difficult for wellsite personnel to understand the behavior of the well.(Solem, 2015)

5. *Inadequate transmitter-receiver positioning:*

By application of pressure fluctuations, tools send commands through mud column to the surface receiver. This takes minutes to communicate to the downhole tools. Moreover, tools must be initially pre-coded to transmit the data of interest. Hence, in certain situations tools cannot transfer required data to the surface. (Schils, Teelken, van Burkleo, Rossa, & Edwards, 2016)

1.2 Problem statement

Recently, the ministry of petroleum and energy has approved the plan for development and operation (PDO) for the Snorre Expansion Project to Equinor ASA. As discussed earlier, the conventional data transfer telemetry has an impact on controlling downhole condition, data gap and hence inefficient drilling performance could be achieved. This thesis work will address the impact of WDPT in improving the issues associated with the conventional mud pulse telemetry. In addition, how the WPD could be implemented in Snorre expansion project (SEP) especially with regards to installation of liners, wellbore clean out operations, temporary plug and abandonment, re- entry, perforations, circulating out pills and completions.(Project), 2019)

1.3 Thesis Objective

Objectives of the thesis work

- To present field case studies of WDP benefits obtained from NCS and other part of the world.

- To discuss the possible application of wired pipe technology for well operations in Snorre Expansion project (SEP) or other field development plans of Equinor ASA.

1.4 Research activities/Method

Figure 1.3 shows the outline of the thesis, which consists of two parts. The first part deals with literature study on the working principles of conventional and wiredpipe telemetry and data quality with more details on the wiredpipe technology network systems. The second part deals with field case studies with the application of wired pipe around the world. Moreover, the alternative application wiredpipe technology for future Equinor ASA operations including snorre expansion project. Here problems and solutions with wire pipe technology will be presented.

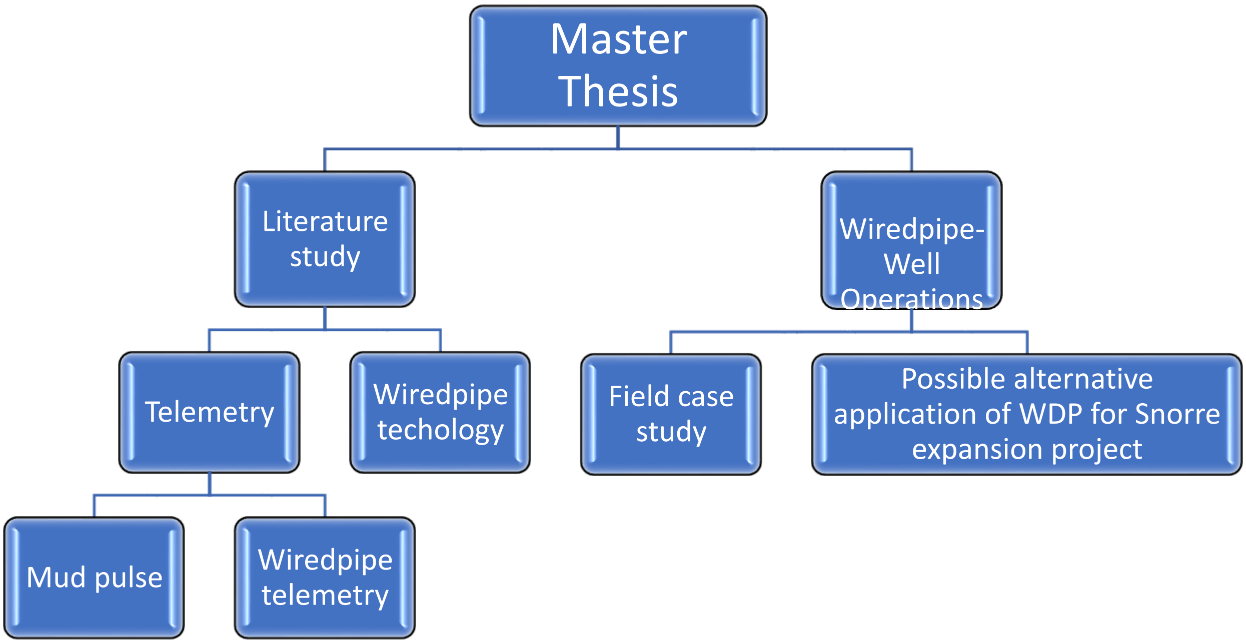

Figure 1.3. Outline of research activities during the thesis.

2 LITERATURE STUDY

2.1 Drilling methods, challenges and solution

2.1.1 Conventional drilling

Drilling in deep-water environment with greater horizontal extent is a challenge with conventional drilling method. The main reason as shown in Figure 2.1, is that the operational window gets narrower for horizontal wells (See Figure 2.2) as depth increases. Hence there is a greater probability to encounter well instability, and kick along with their consequences, such as loss circulation, drill string sticking. To handle these problems, manage pressure drilling and underbalanced drilling methods are introduced as a solution (See Figure 2.3).

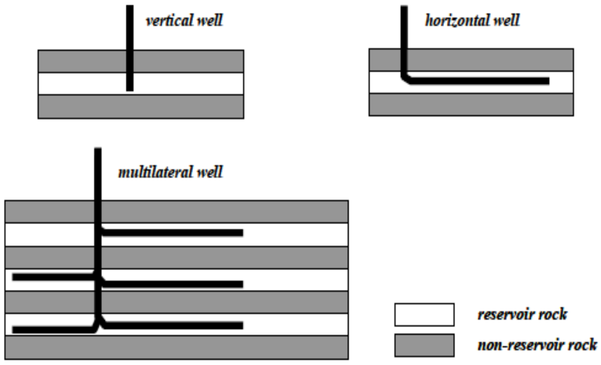

Figure 2.1. Typical well types. (Brouwer, 2004)

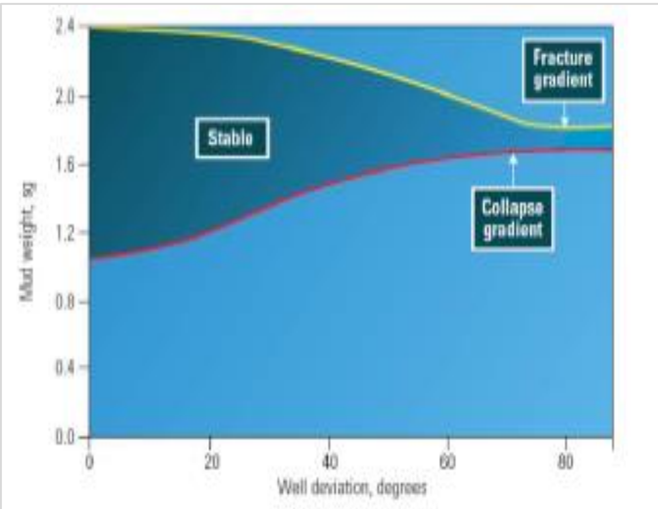

Figure 2.2. Illustration of drilling in horizontal well and the narrow drilling window.(Aldred et al., 1998)

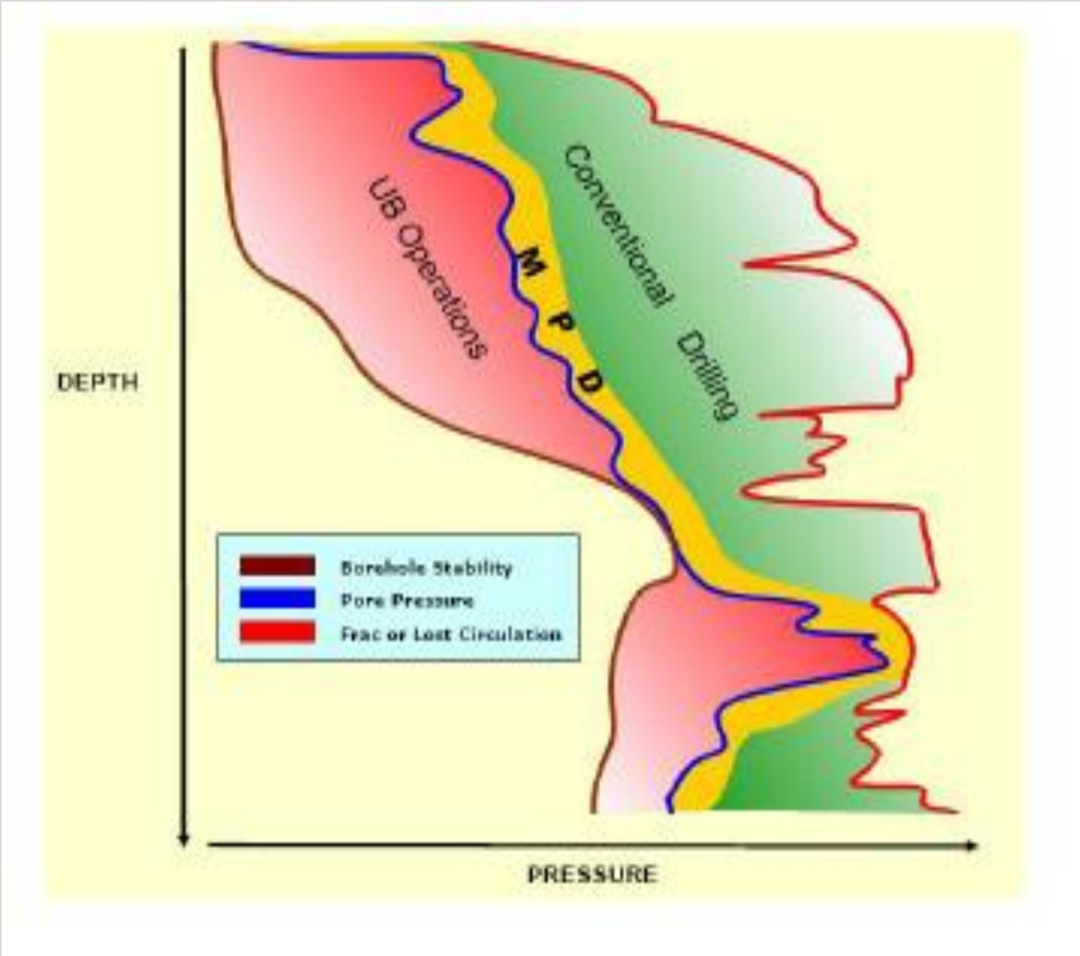

Figure 2.3. Drilling window and application of MPD/UBO for conventional drilling challenges.(Malloy et al., 2009)

2.1.2 Smart well

To drill safely to the maximum length of a reservoir, recently the real time-based operations have been developed in the industry. Smart wells which is also called intelligent wells integrate new technologies, downhole and remotely operated systems with the conventional wells. As illustrated in Figure 2.4, the smart well systems gather data, transmit and analyze in order to optimize or perform remedial actions (Brouwer, 2004; Yeten, Brouwer, Durlofsky, Aziz, & Engineering, 2004)

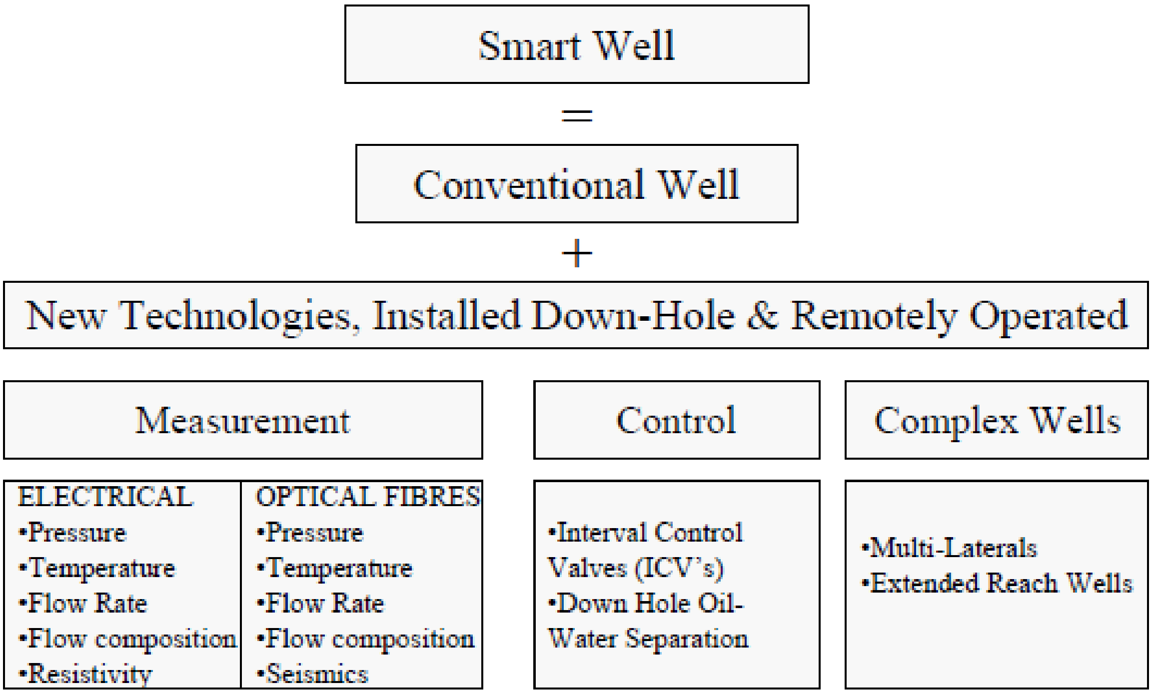

Figure 2.4. Illustration of Smart well. (Brouwer, 2004)

Since the real time data is the key, the quality and speed of data transfer is important. Historically, the first smart/intelligent completion was installed in August 1997 at Saga's Snorre Tension Leg Platform in the North Sea(Xiaoyu et al., 2012) . Unlike the conventional method of data acquisition technique which frequently run interventions, smart wells log data in real-time and hence allows to optimize production. Moreover, it enables operators to monitor in real time as well as to choke or shut any selected zones remotely if the zones shows poor performance. For this, the industry developed electrical control systems and electronic sensors. However, due to poor reliability of the electrical systems, in the recent times service companies developed fiber optic sensors and hydraulic control systems that significantly improved the reliability. Along with the progress of smart wells for enhanced production, the upstream drilling industry has developed WDP which has shown higher quality data transfer when drilling a well.

2.2 Emerging new drilling methods

Advances in technological development enabled to drill deeper, improved drilling performance and increased efficiency by reducing NPT. Figure 2.5 shows the extended reach drilling envelope. The limiting factor affecting this envelope among others are higher torque and drag, which hindered enough load transfer to the bit.

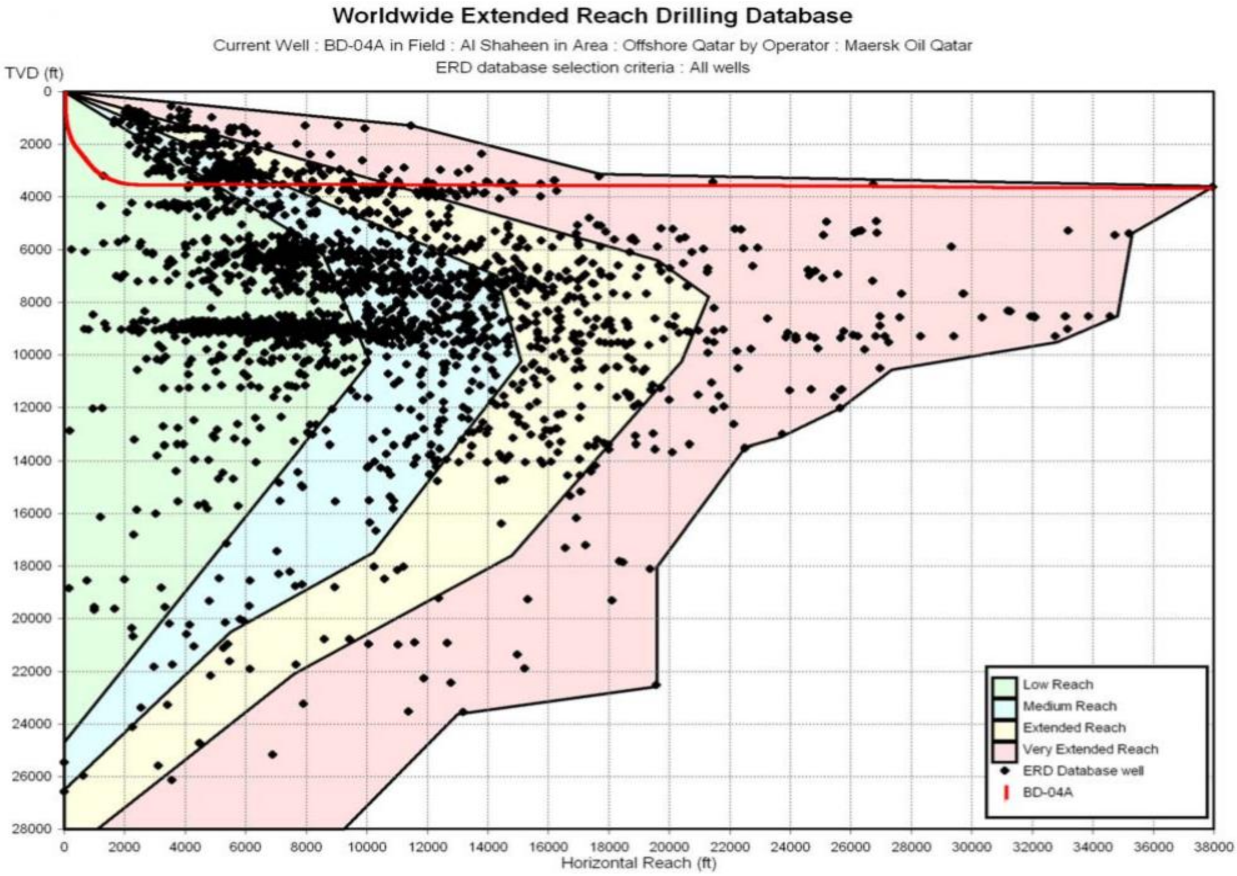

Figure 2.5. Extended Reach Drilling Envelope. (Sonowal, Bennetzen, Wong, & Isevcan, 2009)

2.2.1 Reelwell

ReelWell Company has developed a dual string drilling method to drill a longer offset (See Figure 2.6). The technology provides continuous extra load to the bit which allows to drill ahead. The drilling concept is under research and development and the pilot test results shows promising results. Since the drilling technique is focused to drill longer, the use of high-quality real-time data transfer system makes the method even more efficient. Since the system is dual string, the application of wired pipe drilling method could add more value.

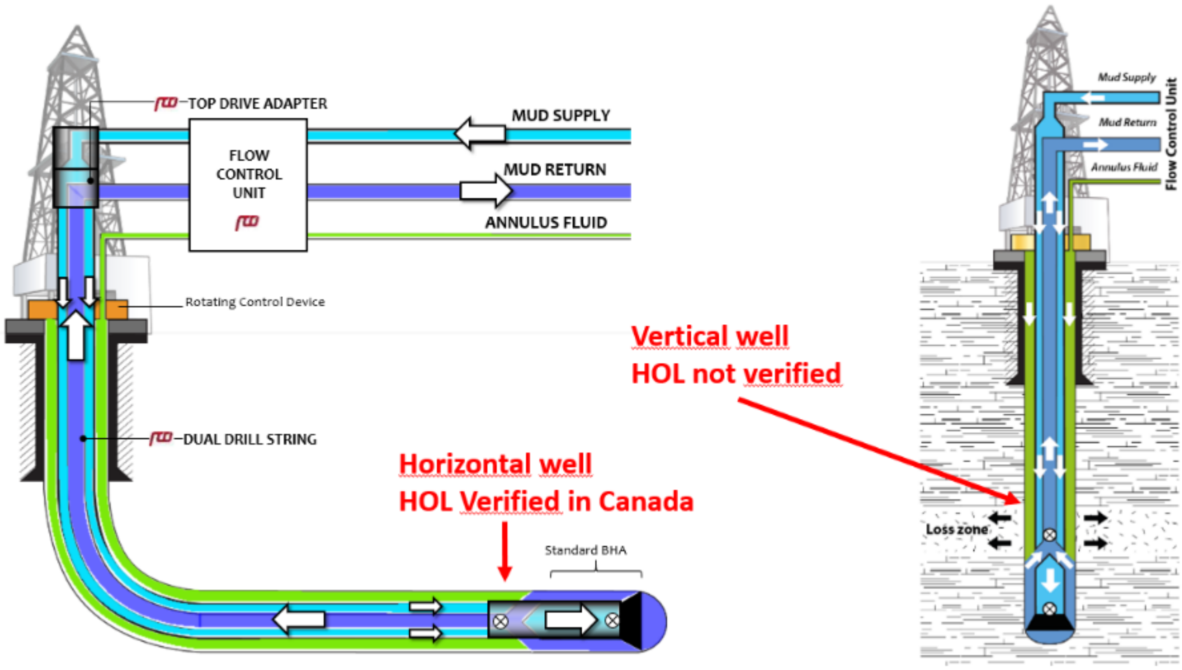

Figure 2.6. Reelwell drilling method. (Vestavik, Thorogood, Bourdelet, Schmalhorst, & Roed, 2017)

2.2.2 Hole in one producer

Hole in one producer (HOP) is a new drilling concept developed and patented by the former IRIS research center, currently Norce As. The idea behind the HOP concept is that it allows simultaneous drilling and completions reaching a distance to 30 km (Stokka et al., 2016). Figure 2.7 and Figure 2.8 show the HOP method that use dual string and flow cross section. According Sigmund et al (Stokka et al., 2016), the HOP system will integrate the available LWD/MWD and directional control technologies. Moreover, it has been pointed out the high-speed telemetry such as wired pipe is also the possible solution. This thesis will review field case studies related to the applications of WDP system. From the results obtained, one can learn how the WDP technology provides more feasibility to the HOP concept.

Figure 2.7a. The pipe-in-pipe liner/casing string with intermediate traction (Stokka et al., 2016)

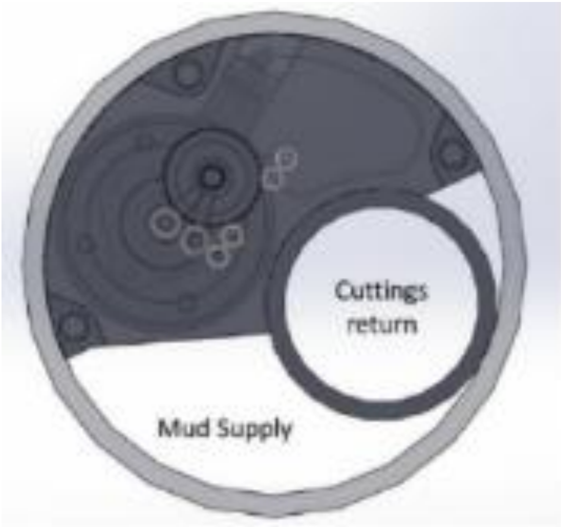

Figure 2.7b. Cross section of the hydraulic power unit (Stokka et al., 2016)

2.3 Conventional data transfer vs wired pipe data transfer

There are several data transfer technologies such as mud pulsing, acoustic signal, electromagnetic telemetry and wired pipe (D. S. Pixton, Asgharzadeh Shishavan, Perez, Hedengren, & Craig, 2014). As displayed in Figure 2.8, the recent years have witnessed the development of wired pipe technology that is capable to transfer large amount of data continuously through the drill string. Acoustic telemetry and Electromagnetic telemetry are used in special cases. Since drilling involves high uncertainties, getting real time data of downhole conditions has become indispensable. LWD and MWD are the two types of measurements used while drilling. Petrophysical data such as resistivity, density and gamma rays can be obtained through LWD while directional surveys such as hole deviations and azimuth are achieved through MWD.

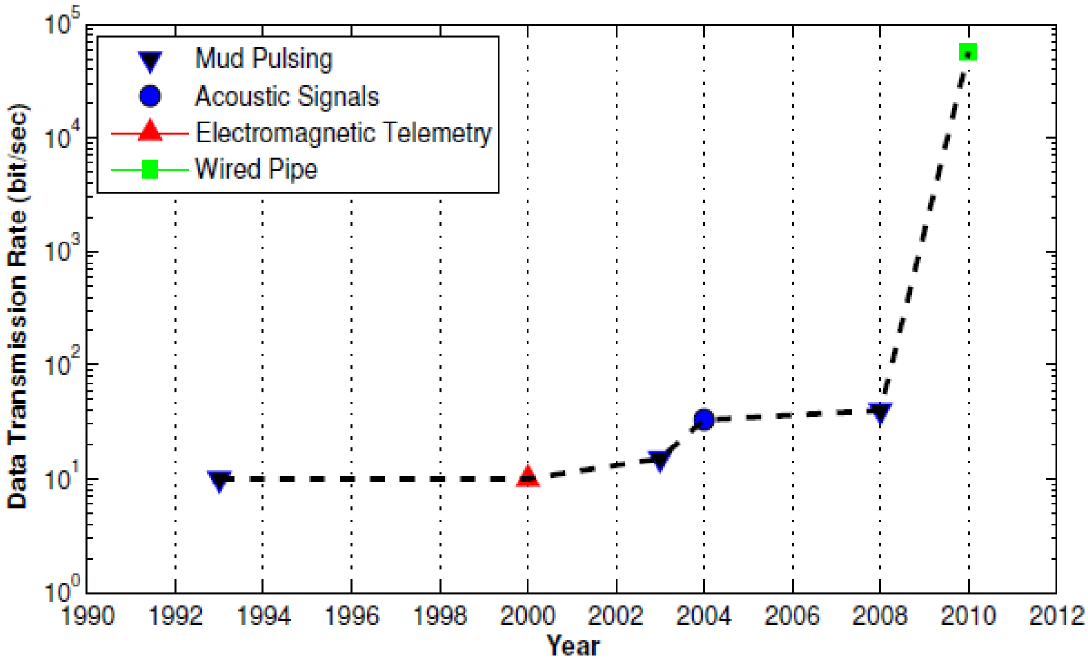

Figure 2.8. Data transmission rate in the drilling industry (D. S. Pixton et al., 2014)

2.3.1 Mud pulse data transfer

Mud pulse telemetry is the most commonly used downhole communication technology in Norwegian Continental Shelf. However due the very low communication frequency, the pulse transmission is 3-6bit/s (Tjemsland, 2012). Figure 2.9 shows mud Pulse Telemetry. A method for transferring signals from BHA to surface by the application of mud column. Transmitter and receiver are the main components of a telemetry system. Based on the kind of information that is being uplinked or downlinked, the transmitter and receiver are often different in MPT. A mud pulser/transmitter is the tool present in the BHA which generates the pressure fluctuation in the mud column. These pressure fluctuations are measured by the sensors present in the surface receiver system. This process is termed uplinking. On the other hand, either by periodically fluctuating the drilling string rpm in proper timed sequence or by differing the rate of flow through the mud pulser, downlinking is achieved. The variation in the pressure or flow is received by the sensors within the MWD tool.

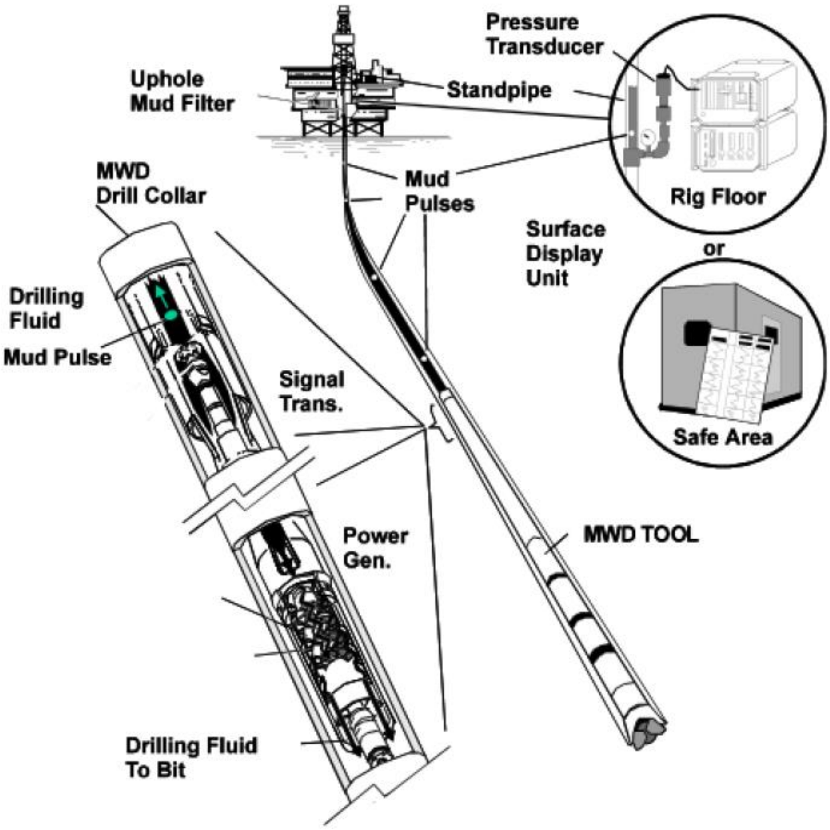

Figure 2.9 Overview of mud pulse telemetry system (Tjemsland, 2012)

As shown in Figure 2.10, mud Pulse Telemetry systems are classified into three main varieties namely a) positive-pulse (b) negative-pulse and c) continuous-wave systems. The pulses of the systems are transmitted/propagated through the mud volume.

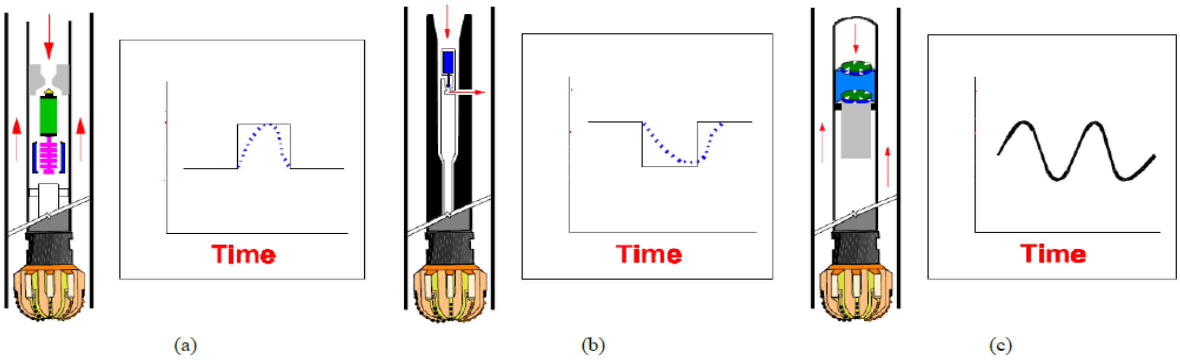

Figure 2.10. Mud pulse a) Positive b) Negative c) Continuous(Hughes, 1997)

2.3.2 Wired pipe data transfer

Operators today rely on downhole data to drill well safely, efficiently and accurately. Conventional telemetry methods such as mud pulse operate only at a few bits per second. Hence significant time is consumed waiting for downhole data. The wired drill pipe is a technology enabler, an optimization and automation product that transfers bi-directional data continuously between the downhole tools and the surface while drilling. This huge increase in the quality and speed of transmission up to 57,600 bits per second in effect improves the coherence of downhole data (Lesso et al., 2008; Solem, 2015). This allows the drillers to perceive well operations with unprecedented accuracy and clarity.

So, with the usage of WDP and the related high-speed telemetry network the data driven activities (vibration, WOB, torque, slide orientation and downlinks) are carried out in matter of seconds. Moreover, it is easier to address the performance limiters such as directional control, data density, well placement, cutting transportation management with higher frequency, limited latency data and attain a much better rate of penetration (ROP). WDP, as a part of closed loop drilling automation system integrates the downhole dynamic measurement tools with the surface performance applications. As ASM tools fetch data from the drilling sections and transmit it straight to surface for analysis. The input algorithms adapt to the changes in the bottom hole conditions and helps the rig to perform.(Measurement, March 8, 2017.)

2.3.3 Comparisons between MPT and Wired pipe on data quality

For real-time diagnostics of downhole related problems, the quality of data and imaging is important. Chris et al (Wolfe, Morris, & Baule, 2009)have presented a paper on high resolution imaging with wired pipe technology that enhance a real-time wellbore stability monitoring. Figure 2.11 shows the comparisons of the mud pulse and wiredpipe dataset. As shown, the wiredpipe gives very detailed formation structure view of the well fracture, which is associated with the failure. On the other hand, the mud pulse does not image clearly the well fracture events.

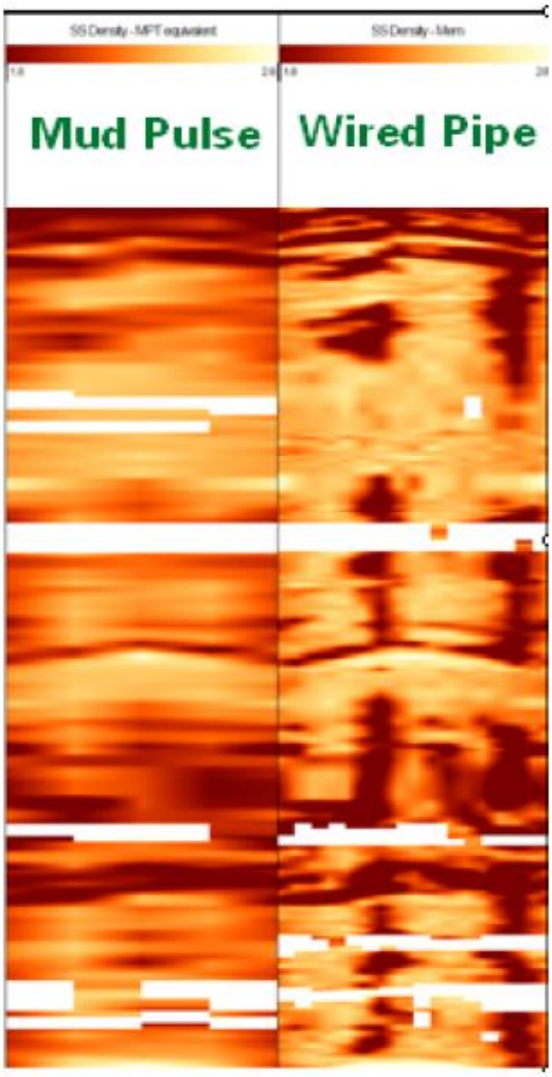

Figure 2.11. Comparisons between wired pipe and mud pulse image. (Wolfe et al., 2009)

2.3.4 Drilling dynamics

Figure 2.12 illustrates the comparisons between co-pilot wired pipe and mud pulse transmitted dataset. As shown the mud pulse data are received at surface approximately every other 2 minutes. The wired pipe data contained a very detailed information than the mud pulse dataset. It can be observed that the mud pulse was not able to send useful information due to which remedial action might not be taken instantaneously. This demonstrate the how wired pipe telemetry is superior over the mud pulse data transmission in terms of data quality and usefulness of the real time diagnostic downhole problems such as vibration, and well instability control issues.

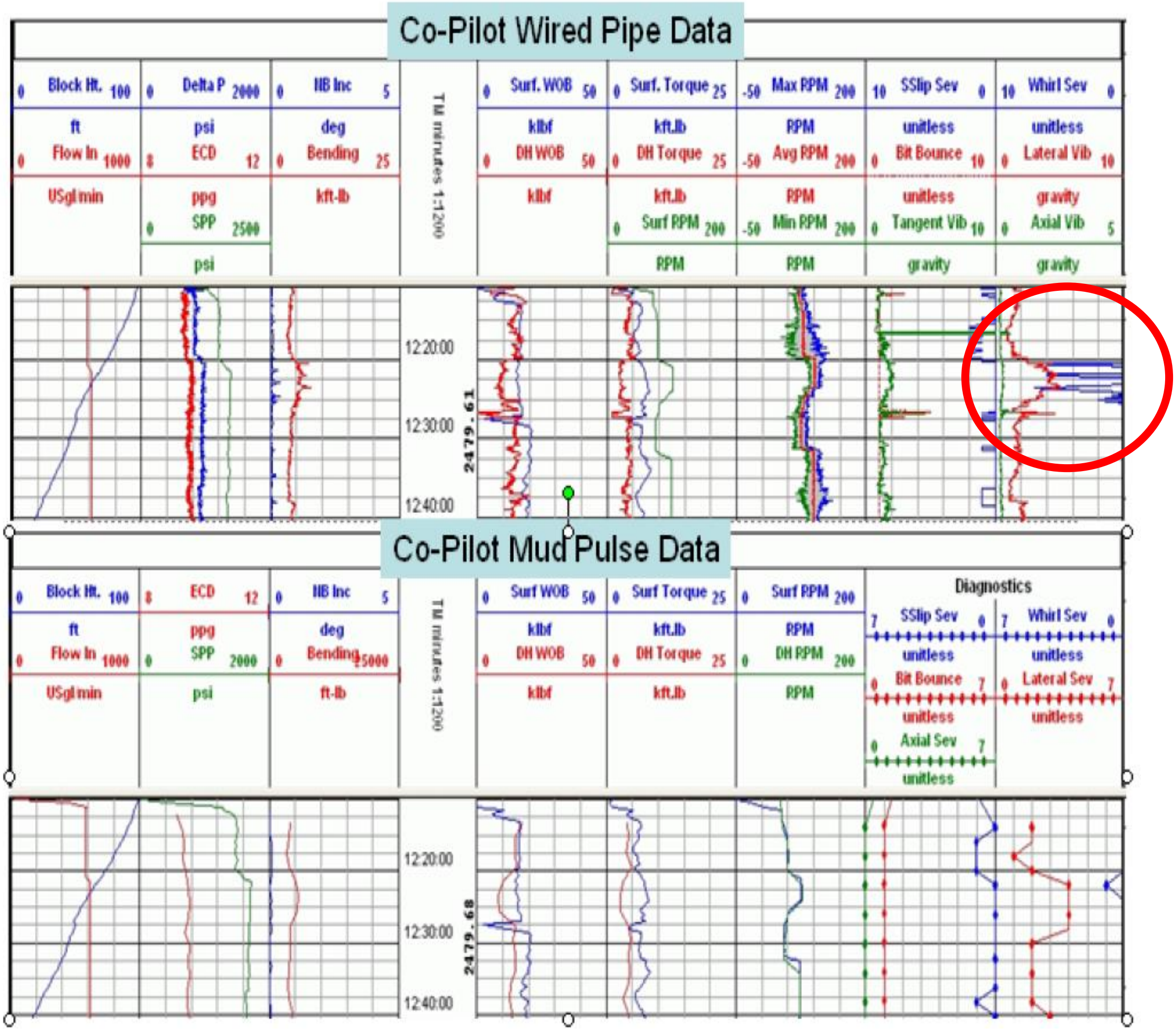

Figure 2.12. Comparison between the data quality transferred via wired pipe and mud pulse. (Wolfe et al., 2009)

Another example is shown in Figure 2.13 (Sehsah et al., 2017). Due to the fast telemetry with wired pipe (57,000bit/s) compared to the mud pulse transmission (3-6bit/s), it is observed that there is no restriction on the data points sent to the surface. But this is not the case with the mud pulse. Hence, it can be observed that at high ROP, there are data gap associated with the mud telemetry while no gaps and high-density images are achieved with the Wiredpipe data.

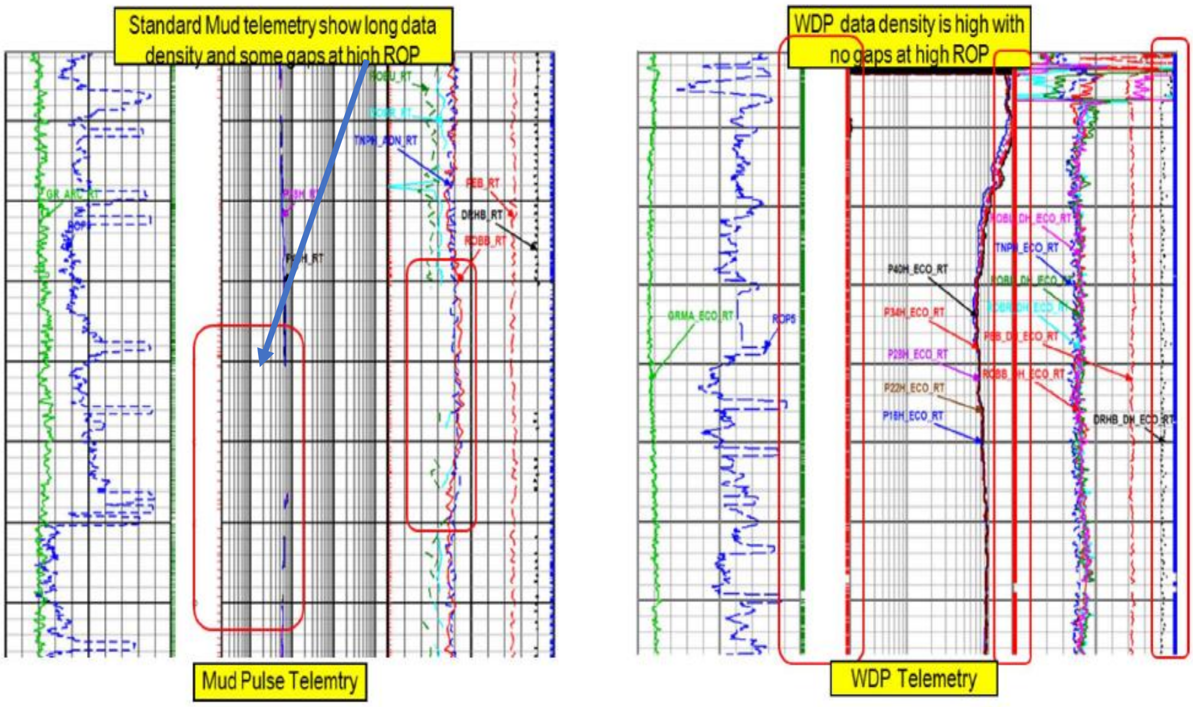

Figure 2.13. Comparisons of mud pulse telemetry (left) and WDP telemetry (Sehsah et al., 2017)

2.4 Wired pipe technology

Wired Pipe technology is a high-speed data network that provides a real time communication between downhole tools and the surface systems through WDP and other wired components in the drill string. The downhole network comprises of:

- Data Swivels™,
- Datalinks™,
- Wired drill pipe and
- Special components such as reamers, stabilizers, jars and IBOPs.

Figure 2.14 shows the wired pipe network and outline the relationship between downhole components and networked components at the surface.

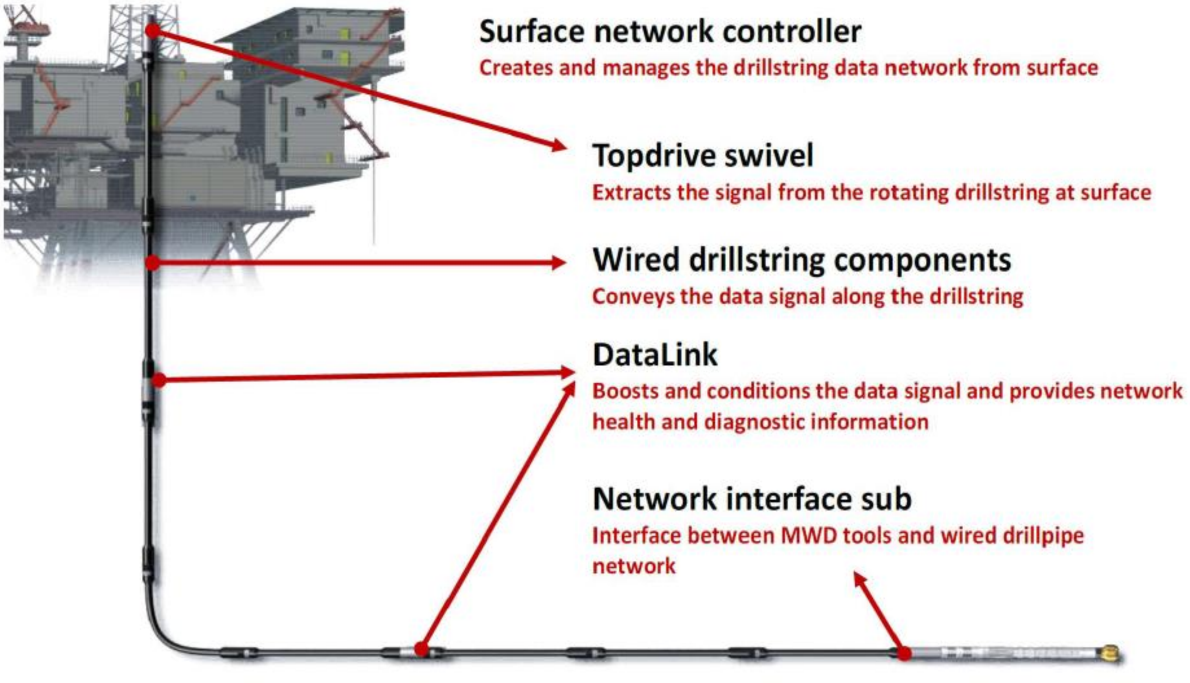

Figure 2.14. Outline of WDP network (NOVMaterial)

2.4.1 Surface Network controller and surface cabling (NetCon)

Network controller is required for securely transferring tool commands and data in real time to multiple users from a local user. Specially designed network cabling named surface cabling is configured to understand the daily rig activities. This includes every required cables and corresponding junction boxes for installation. Surface cabling is installed throughout the rig structure which provides transmission of data from data swivels to the surface network as shown Figure 2.14.

2.4.2 Data Swivels

The transmitted data between downhole system and the surface pass through a special connection termed as Swivel. This is attached below the top drive. Shown below, the data swivel is a two-part tubular component which uses a rotor and a stator for providing a path between surface stationary system and downhole rotating portion of the network.

The data swivel is the critical part of the wired pipe system. Based on the top drive configuration, the swivel can be installed between the saver sub and IBOP or above the IBOP.

2.4.2.1 Top Drive Swivel

The top drive swivel provides an interface between the stationary and the rotating systems installed at the bottom end of the top drive assembly. It comprises of a sub, through which network traffic passes into the swivel.

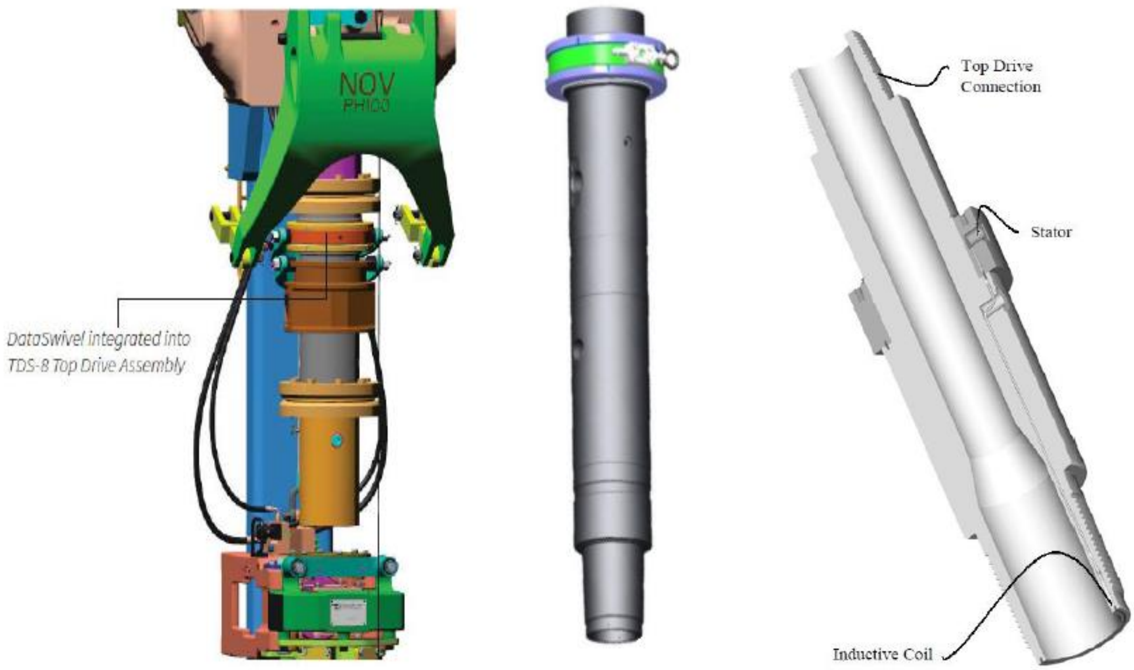

Figure 2.15. Data Swivel placement in top drive(NOVMaterial)

The stator is directly connected to the surface network and during the drilling operation, it is held at position by the anti-rotation cables. The rotor is directly connected to the string and during well operations, it moves freely. Also, a pair of special concentric electromagnetic coils are placed between the stator and the rotor.

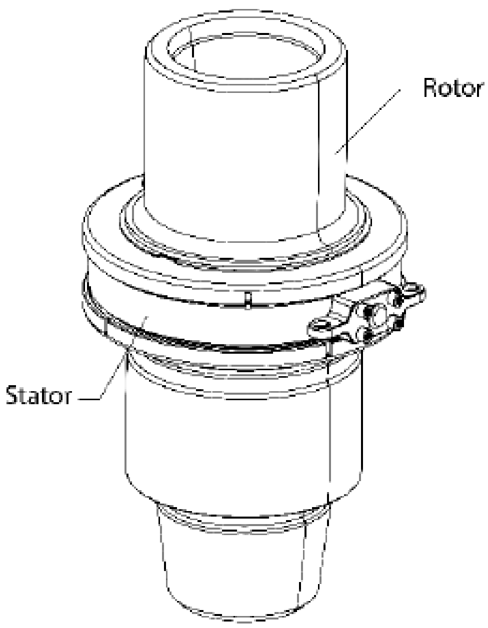

Figure 2.16. Data swivel components (Reeves, Payne, Ismayilov, & Jellison, 2005)

2.4.3 Wired Drillstring

Wired pipes appear like any regular drill pipe. However, it provides additional components and features that allow data transmission between the surface and downhole tools. Each drill string component in this network consists of two electromagnetic coils connected by DataCable.

Figure 2.17 shows the data transmitted travels along the data cable present inside each wired component and over the box and the pin end coils at every connection. The electromagnetic coil transfers bidirectional data via transduction, thus avoiding the requirement for a straight electrical connection. When connections are made up, the coils reach each other. Since the coupling is inductive, there is no requirement for them to touch each other for signal transmission.

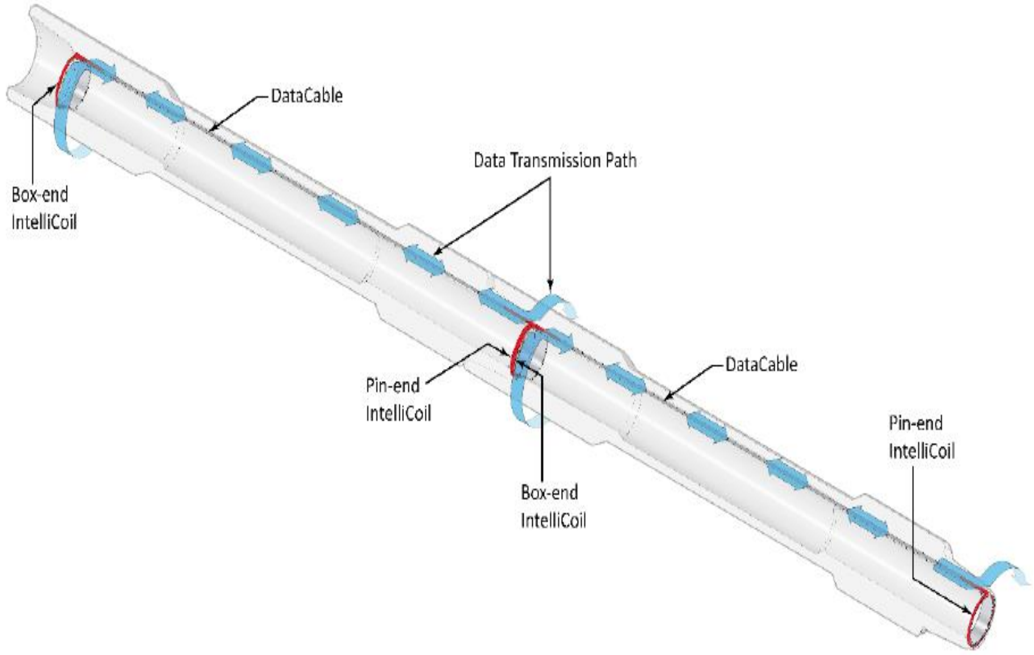

Figure 2.17. Bi-directional data transmissions(NOVMaterial)

2.4.3.1 Wired Components

- Coil

The coil acts as a communication device fixed at the box and pin ends of the tubulars and connected along the string by a cable. The round shaped transducer helps to carry the bi-directional data to the drillstring components from the surface without the requirement for a straight electrical connection.

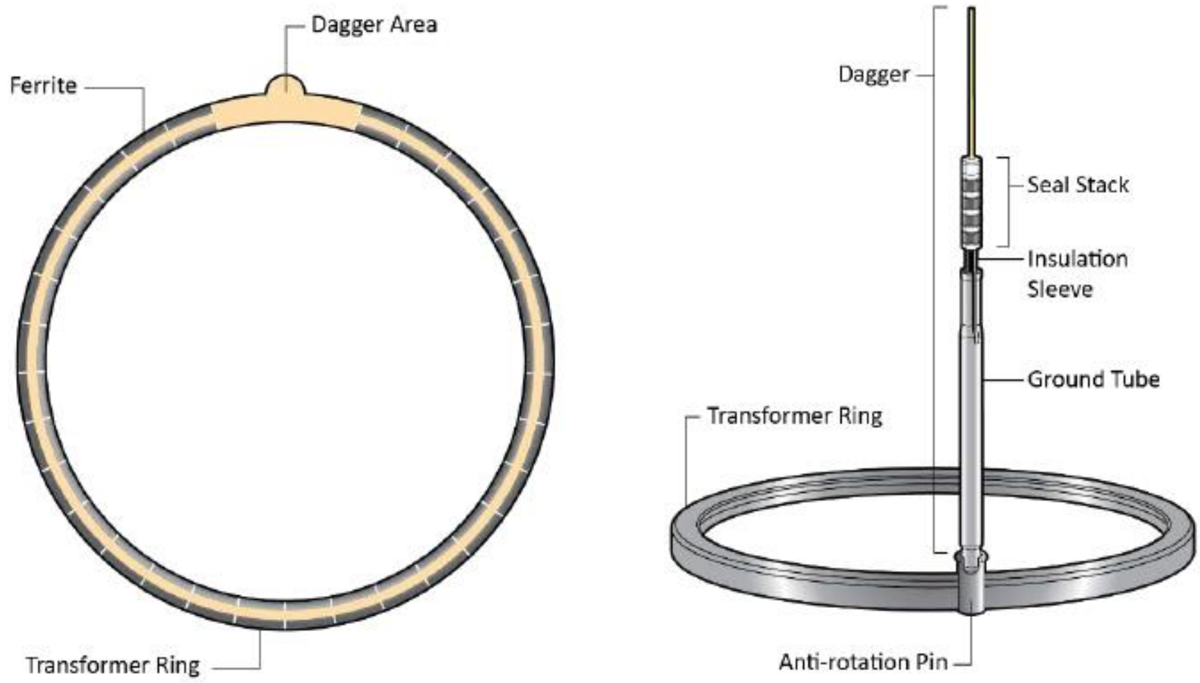

Figure 2.18. V2 Intelli Coil - Latest Version(NOVMaterial)

As shown in the figure above, the coil includes a transducer coil and a perpendicular dagger. This is secured by a ground tube, a seal stack, dielectric insulation, an anti-rotation pin. The seal stack shields the connection from interfering with drilling mud, gases or brine flowing in the drillstring.

- Cable

An armored co-axial cable is sheathed in metal pipe to protect from drilling fluids and cuttings. This is engineered in a specific form to carry high speed data with less power loss. The cable is held in tension throughout the tubular between the box and pin ends. This is the path for data transmission. The connection between the coil and the cable are created in a high-pressure connection which is designed for extreme drilling environments.

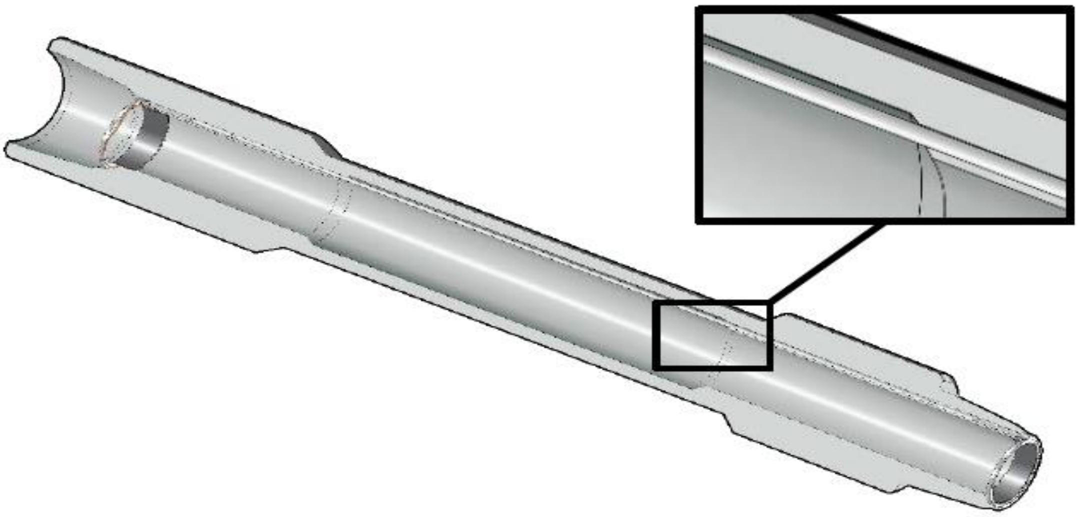

Figure 2.19. Data cable entry point (NOVMaterial)

- Tubulars:

All tubulars such as drillpipe, drill collar and heavy weight drillpipe is changed to provide higher strength and speed cable across the internal diameter and coils in box and pin end secondary shoulders. The new wired pipe tubulars feature plastic coating internally, longer tool joints, harder banding and a wider range of different steel grades based on proper downhole environment. When wired tubulars are connected the coils provide an uninterrupted high-speed transmission of data across the cable and over the length of drillstring.

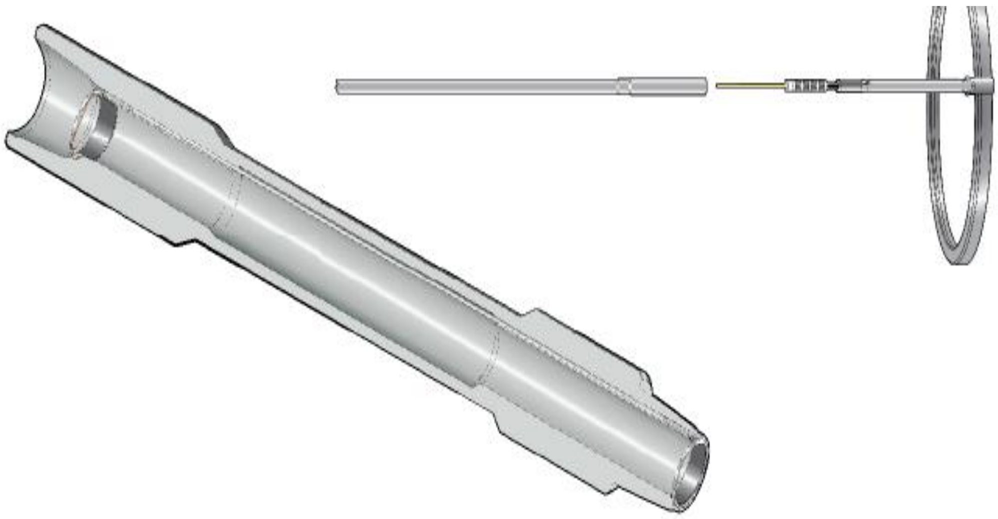

Figure 2.20. WDP with DataCable and IntelliCoil (NOVMaterial)

2.4.3.2 Wiredpipe version 1 and Version 2

The first version (Version 1) of WDP were commercialized and available on the market in 2006(D. Pixton & Craig, 2014). In the initial installation of WDP version 1, there were certain issues encountered such as (Sehsah et al., 2017)

- Connection issues were one of the common and major reliability incidents (Wilson, 2013). Also, overtorquing and improper stabbing issues contributed to the WDP connection damages.
- Data interpretation was another major failure. (e.g. booster sub functionality failures)
- In certain deep-water operations, the use of specific drilling fluid contributed to stress corrosion.

Since then, after continuously analyzing the performance and incorporating the lessons learnt from wells drilled with Version V1 wired drill pipe, the industry has made some technological improvement and Version 2 became available for field application since 2015. Figure 2.22 shows the difference between the two designs coil placements(Sehsah et al., 2017)

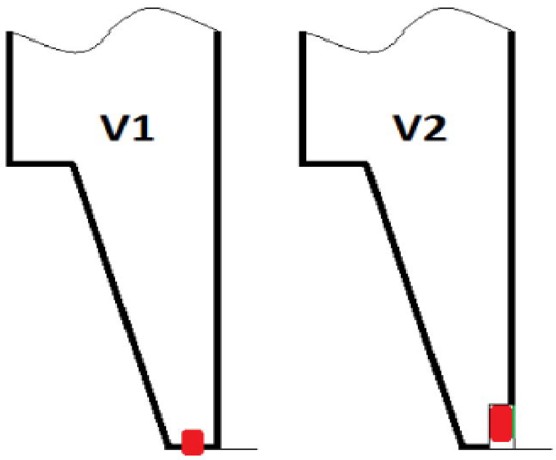

Figure 2.21. Version 1 and Version 2 WPD's coil placement (Sehsah et al., 2017)

As shown in Figures 2.23 and 2.24, the coil of the Version-1 is placed at the center surface of the PIN. The disadvantage with this version 1 design is that in over torque situation, several crack failures could occur and will pull apart the coil. Version 1 is more exposed to flaring and Version 2 is independent of PIN deformation. As illustrated in Figure 2.23, the coil of Version

2 is placed on the side of the PIN instead of being on the surface, so that PIN coil is more protected from shocks and mechanical damages than version 1.

Figure 2.22. Wired pipe version 1 and version 2 coil mounted in the center of the shoulder of the PIN(NOVMaterial)

The version 2 coil is connected with the inner diameter of the PIN. This design has two improvements. Firstly, the coil will not be pulled by the action of flaring, and secondly, the new ID design is suitable for the clip system to fix the coil and makes the connection easier.

Figure 2.23. Version 2 design as being field removable and replaceable (NOVMaterial)

The version was put out with better connection strength to face the aggressive profiles and the torsional requirements. The initial stress corrosion issue was addressed by changing the pipe material where the data cable was placed. This was changed to inconel from stainless steel. This addressed the corrosion problem but slightly increased the cost of WDP. (NOVMaterial)

2.4.4 DataLinks

The datalinks installed between the drillstring transmit the required data between the surface systems and downhole tools. Typically, DataLinks are placed at every 1400ft to 1500ft increasing the signal strength and ensuring no data is lost during transmission. All datalink includes an electronic sub and an adapter sub. The adapter sub is a normal drill pipe connection at the box end. It has a special connection at the pin end which attaches the electronic sub as shown below.

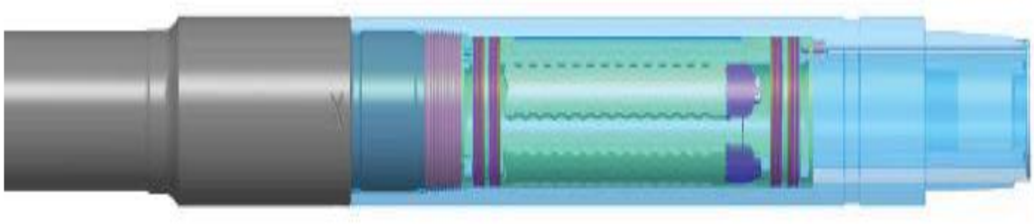

Figure 2.24. Internal components of the sub (NOVMaterial)

The electronic sub is powered by lithium battery for the datalink. The operational lifetime is 60 to 90 days for the lithium batteries using a low power mode when not used. The battery life can be monitored through the software to suggest the next change in battery system at onshore.

To acquire the along string measurements, the data boosters are fitted with temperature and pressure sensors. ASM tools can acquire bore and annular pressure, rotational velocity, temperature and three-axis vibration data at higher frequencies. EMS tools can acquire downhole torque and weight in addition to rotation, internal pressure, annular pressure, three-axis vibration, and temperature at rates up to 800Hz. (NOVMaterial) A battery power sub is installed at every 1500 feet (approximately) for boosting signal strength. ASM can be connected in the booster assembly. Providing regular amplification is important to maintain the intensity of data transmission. The usage of data link at defined intervals along the drillstring amplify the transmission and prevent the data loss. This helps in extending the length over which the data could travel in the network. The connection between the data links and the wired pipe, enable the downhole tool providers to view the live data from the tools located in the drillstring and the BHA. With the help of interface sub, WDP provides connection to the steering assemblies/measurement providers. The interface sub holds a transceiver board which enable the tool providers to transmit data based on required needs.

Figure 2.25. Enhanced measurement system ((EMS), March 8, 2017)

Figure 2.26. Along string measurement (ASM)

2.5 Application of real-time data

2.5.1 Hydraulics model vs real-time data

During drilling, the prediction of hydraulics is important for well pressure control, cutting transport and determination of pump pressure. The effect circulation density (ECD) is given as (Lapeyrouse, 2002):

$$ECD = MW + \frac{\Delta P_{annulus}}{0.0981 \cdot TVD}; \qquad [sg] = [sg] + \frac{[bar]}{[m]} \tag{1}$$

Where

$\Delta P_{annulus}$ = pressure drop in the annulus, MW = static mud weight, TVD = true vertical depth to the point of interest.

The calculation of hydraulics assumes the transport medial is uniform. However, in the real well, the well size and the eccentricity of the drill sting varies. The pressure can be calculated from Darcy formula as (Mitchell & Miska, 2011):

$$\Delta P = \frac{f \rho V^2 L}{2D} \tag{2}$$

Where,

f = friction factor, L =length of the flow line, ρ =density of fluid, u_m is the average velocity and, D =hydraulic flow size.

The friction factor f is a function of Reynonlds number and surface roughness is given by Haaland (Massey, 1989)

$$\frac{1}{\sqrt{f}} = -1.8log_{10}\left\{\frac{6.6}{R_e} + \left(\frac{\varepsilon}{3.71}\right)^{1.11}\right\} \quad (3)$$

Where,

ε = surface roughness coefficient ε = k/d, k = surface roughness and d = diameter of the pipe

Hans et al (2008) have compared North Sea field measured hydraulics data with the model called WeMod. Figure 27 shows annular bottom hole pressure and the standpipe pressure. As shown, a discrepancy between the measured and the modelled data. This shows that the model is not capable of predicting the measurement. There are a lot of uncertainty in the model parameters, such density, friction factor and well geometry as well.

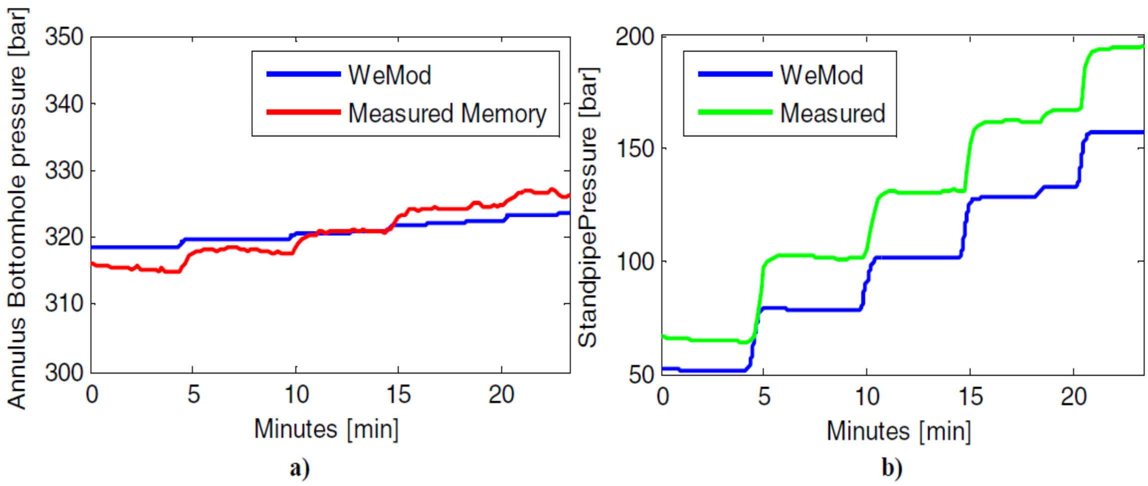

Figure 2.27. Comparison between hydraulics model and measurement (Lohne, Gravdal, Dvergsnes, Nygaard, & Vefring, 2008)

Since the model doesn't capture all the physics, authors have introduced a calibration factor called, C and they set the friction factor value just 1. Equation 2 is modified as Eq.4:

$$\Delta P = c\,\frac{f\rho V^2 L}{2D} \quad (4)$$

Based on the measured data, the authors have calibrated the annulus and drill string pressure by generating the dynamic calibration factor as shown in Figure 2.28

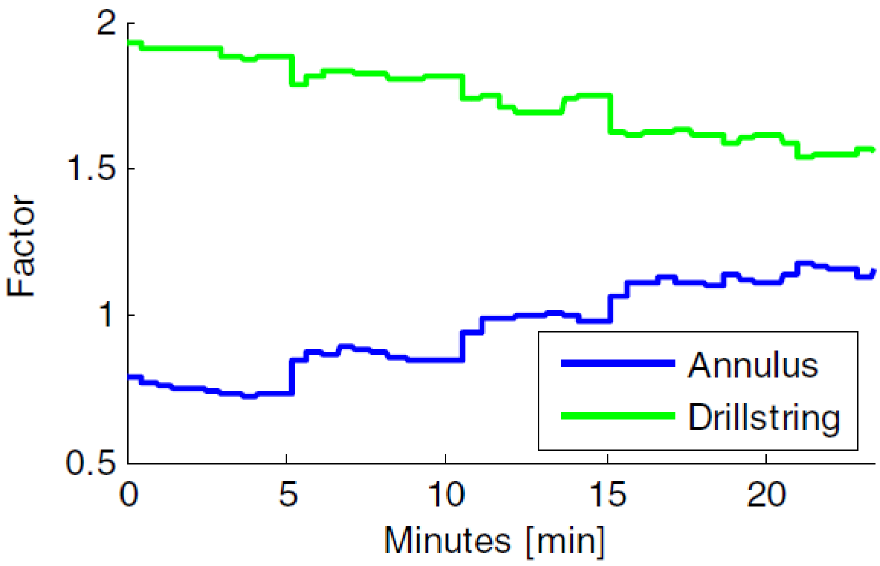

Figure 2.28. Dynamics drill string and Annulus Calibration factor (Lohne et al., 2008)

The WeMod hydraulic model is adjusted with the dynamic calibration factor and the resulting perfect match with the measurement is displayed as in Figure 29. The results illustrate the need to have a real time downhole measurement to accurately calibrate the model. For this the high-speed telemetry system WDP plays a significant role both in terms of a higher rate data transmission with less noise.(Lohne et al., 2008)

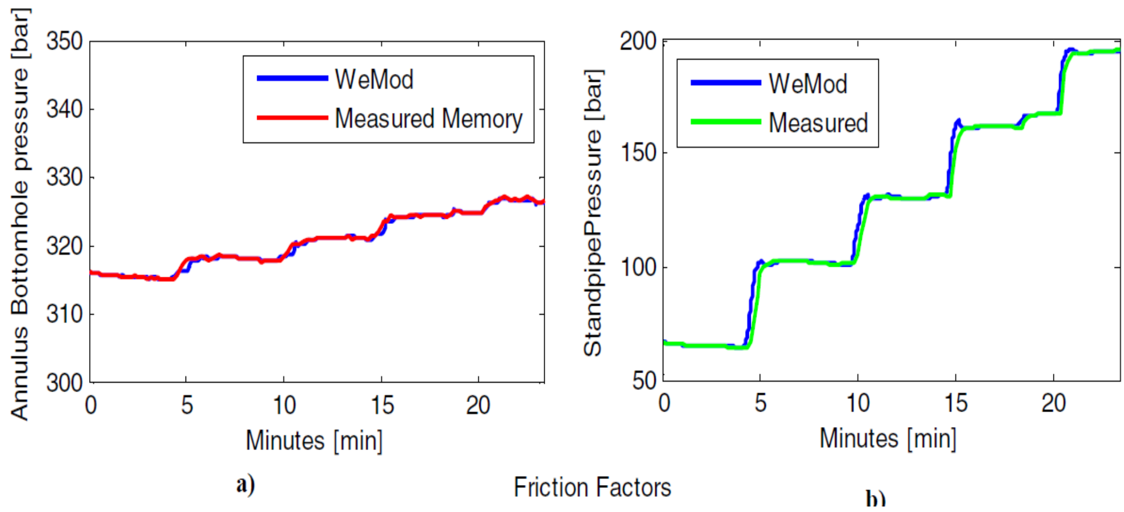

Figure 2.29. Comparison between hydraulics model and measurement after calibration of the WeMod (Lohne et al., 2008)

Figure 2.30 also shows the real time measurement and the model calibration with different factor at different time

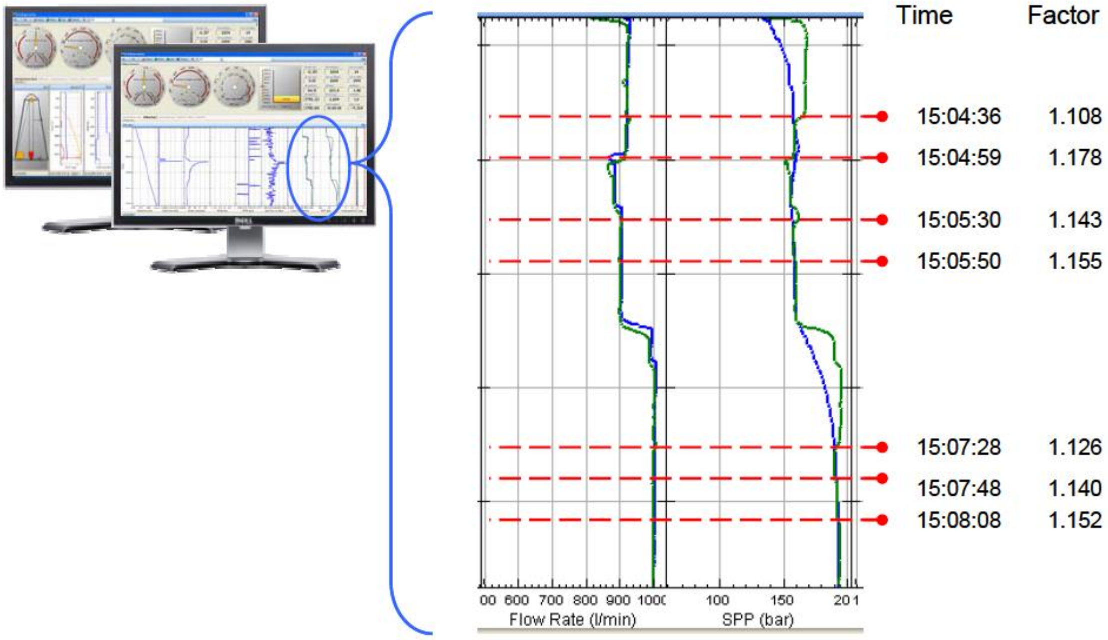

Figure 2.30. Example of automatic model calibration based on real time data (Gravdal, Lohne, Nygaard, Vefring, & Time, 2008)

2.5.2 Friction determination

Drill string mechanics is an important issue during drilling operation. Figure 2.31 displays the drill string loaded with axial and torsional loads.

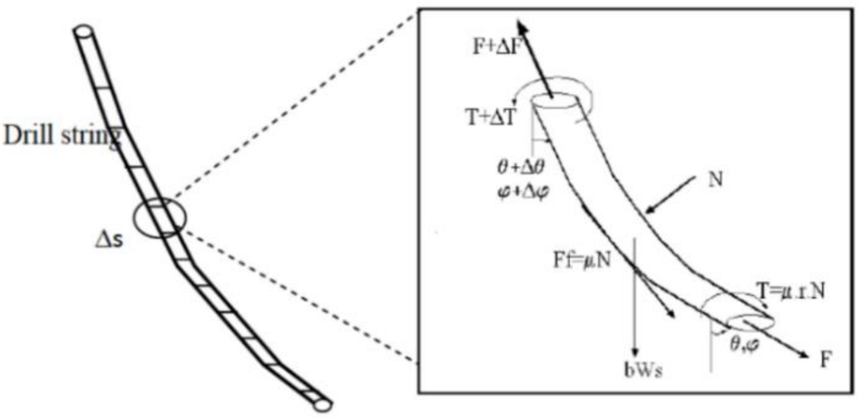

Figure 2.31. Segmented drill-string and distribution of loads at each segment [Mesfin lecture,2019]

Applying the force balance, the one can obtain the differential force equation given as (Johancsik, Friesen, & Dawson, 1984)

$$\frac{dF}{ds} = \pm \mu_a \left[\sqrt{\left[\beta w_s \sin(\theta) + F\frac{d\theta}{ds}\right]^2 + \left[F \sin(\theta)\frac{d\varphi}{ds}\right]^2} \right] + \beta w_s \cos(\theta) \qquad (2.1)$$

As shown the model is a function of coefficient of friction. Similarly, the torque is expressed as:

$$T_{i+1} = T_i + \sum_{i=1}^{n} \mu_t r_i N_i (S_{i+1} - S_i) \qquad (2.2)$$

Where N_i is contact forces, which is given under the square root in Eq. 3.48.

Figure 2.32 shows an example of the simulated hookload road map plotted against the measured free rotating and slack-off weight. As show, the simulation is based on a constant value, which is normally used a typical value. However, one can observe a significant deviation between 6500-7900m. This shows the need to determine the real time coefficient of friction in order predict the hookload accurately. Figure 2.33 and 2.34 illustrate the computed coefficient of friction based on the wiredpipe (WP) and drilltronics^{TM} (DT) sensor measured data. As shown, both figures, the rotating friction and the sliding friction are equal as well as the friction coefficient value is not a single value to be used for the whole drilling section as shown in Figure 2.32 It should be determined in real time.

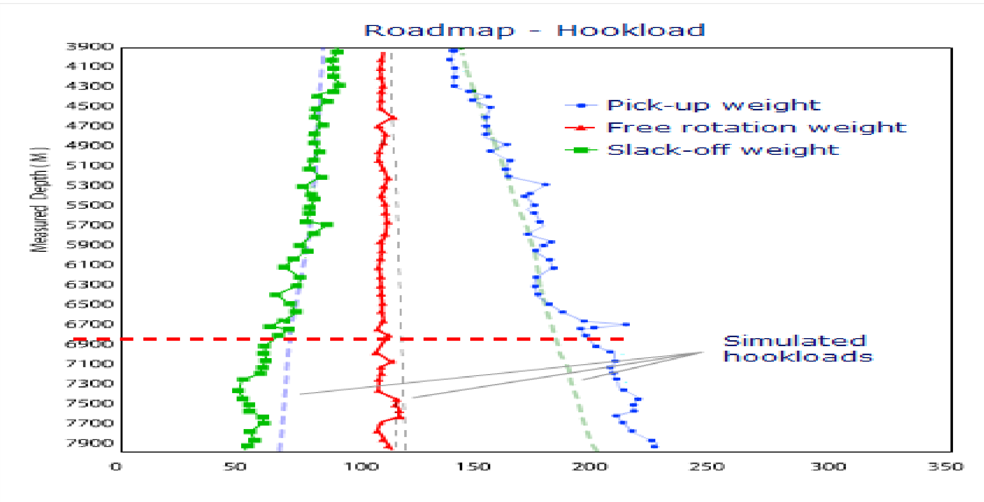

Figure 2.32. Simulated and measured Hookload road map (ASA)

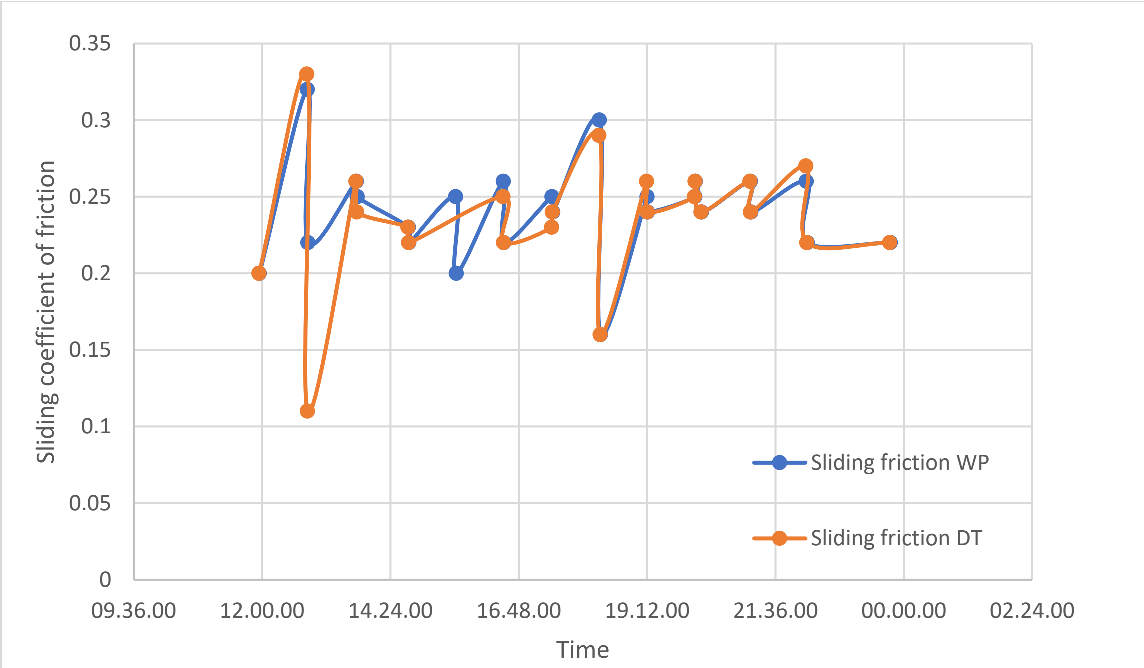

Figure 2.33. Sliding coefficient of friction based on WP and drilltronics measured data (ASA)

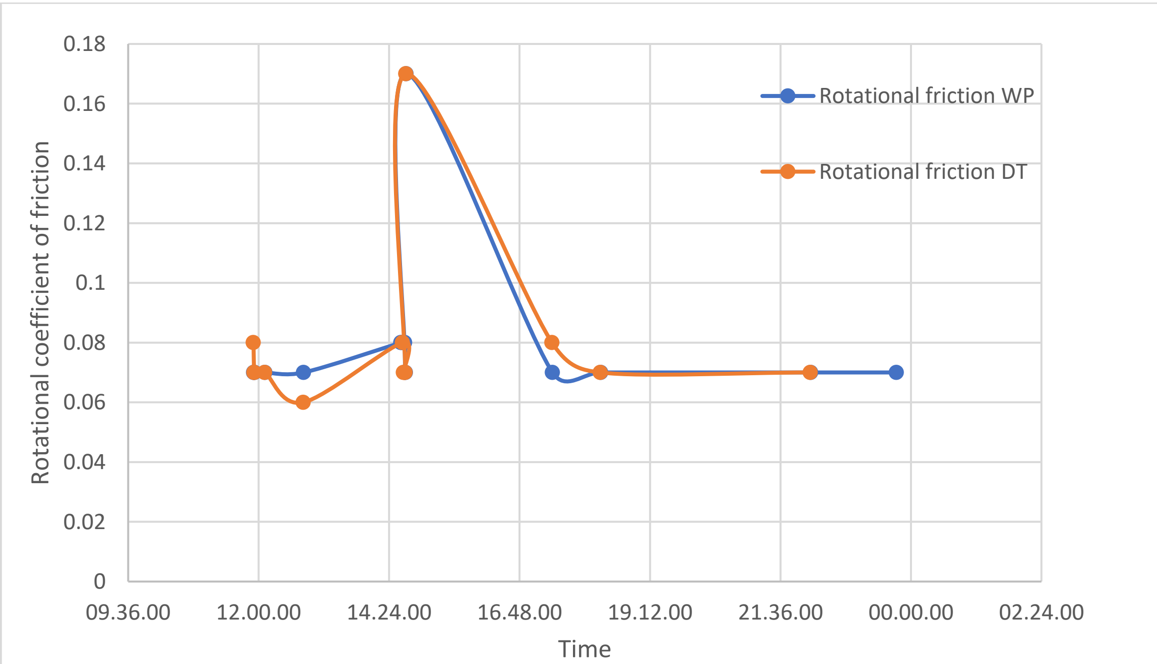

Figure 2.34. Rotational coefficient of friction based on WP and drilltronics measured data (ASA)

3 FIELD CASE STUDIES

In this chapter a total of eight field case studies have been conducted on wells selected in different parts of the world. In the discussion below, the operational aspects and the benefits obtained from the wired pipe telemetry will be presented. From the study, later the application of wiredpipe for the Snorre Expansion Project will be proposed.

3.1 Babbage development field

In Babbage field development project, operator have implemented wired drill pipe technology and saved several days per well by increasing drilling efficiency.

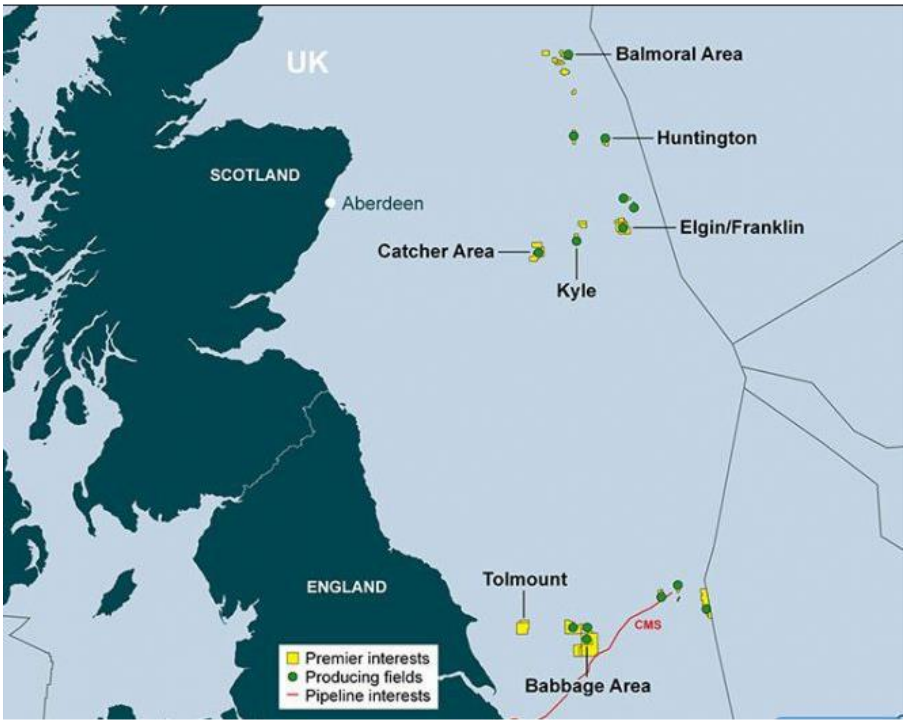

Figure 3.1. Babbage field location map Babbage field location map (Teelken et al., 2016)

Babbage development project then operated by EON E&P UK (the Central North Sea) consisted of five wells drilled in two phases. The first phase project in 2011 had three wells while the second phase project carried out in 2013 had two wells drilled. However, the directional providers were different for the two phases. This project exploited WDP during geo-steering and subsequent well placement. The time savings and the corresponding efficiency gains due to instant data transmission up and down the drill string are discussed here. Of all the five wells taken into consideration for the study, two wells used WDP and the rest were drilled by conventional MPT. This field case study compares the time involved in different operations such as on-bottom drilling, downhole data transmission and vice versa, BHA trip etc. The analysis also took into consideration the well path, downhole tool design and the drilling practices.

The time saved in the operation is categorized into four major areas: 1. Instantaneous Data Transmission, 2. Frequency of BHA Trips, 3. Drilling Optimization/ Performance and 4. Other efficiency improvement methods.

Instantaneous Data Transmission

The final two sections in the well (8.5" and 6" reservoir section) used WDP telemetry. Hence the appropriate estimated results and the BHAs used for these two respective sections are shown. The BHAs used in the last two section of the well is shown in the table below:(Teelken et al., 2016)

Telemetry used	Drilling Phase + directional provider	Hole size	BHA configuration	Reason pulled	Footage drilled	Number of Bit/BHA runs to TD	Number of tool failures
		inch			ft	per well	per well
Well 1: MPT	Drilling Phase I Directional Provider I	8.5	MOTOR	TD	1280	6	1
		6	RSS	DTF	5		
			CLEAN OUT	BHA	14		
			RSS	HR	1064		
			RSS	HR	1579		
			RSS	TD	1341		
Well 2: WDP		8.5	MOTOR	TD	1617	3	0
		6	RSS + MOTOR	BHA	2068		
			RSS	TD	1565		
Well 3: WDP		8.5	MOTOR	TD	2025	4	1
		6	RSS + MOTOR	BHA	1151		
			RSS + MOTOR	DTF	1375		
			RSS + MOTOR	TD	1468		
Well 4: MPT	Drilling Phase II Directional Provider II	8.5	RSS	PP	1442	7	4
		8.5	RSS	TD	232		
		6	RSS	DTF	417		
			RSS	DTF	4		
			RSS	DTF	1891		
			RSS	DTF	0		
			MOTOR	TD	1944		
Well 5: MPT		8.5	Steerable Turbine	DTF	1468	6	1
			Steerable Turbine	LIH	475		
			Steerable Turbine	TD	1487		
		6	Steerable Turbine	BHA	419		
			RSS	PR	2553		
			RSS	TD	1636		

Table 3.1. BHA configurations and number of runs(Teelken et al., 2016)

Assuming a similar mean time between failures (MTBF) from both the directional drilling providers:

- the complete drilled footage for the three wells using MPT was 19, 251 foot. Six tool failure was experienced throughout.
- Hence the mean for the MPT well = *3.12 tool failures/ 10,000ft drilled.*
- the complete drilled footage for the two wells using WDP was 11, 269 foot. One tool failure was experienced throughout.
- Hence the mean for the WDP well = *0.89 tool failures/ 10,000ft drilled.*

The verified stationary times which was required for the transmission of data within each specific operation were observed and examined for each well.
For each well, the telemetry time is shown below in figure 3.2.

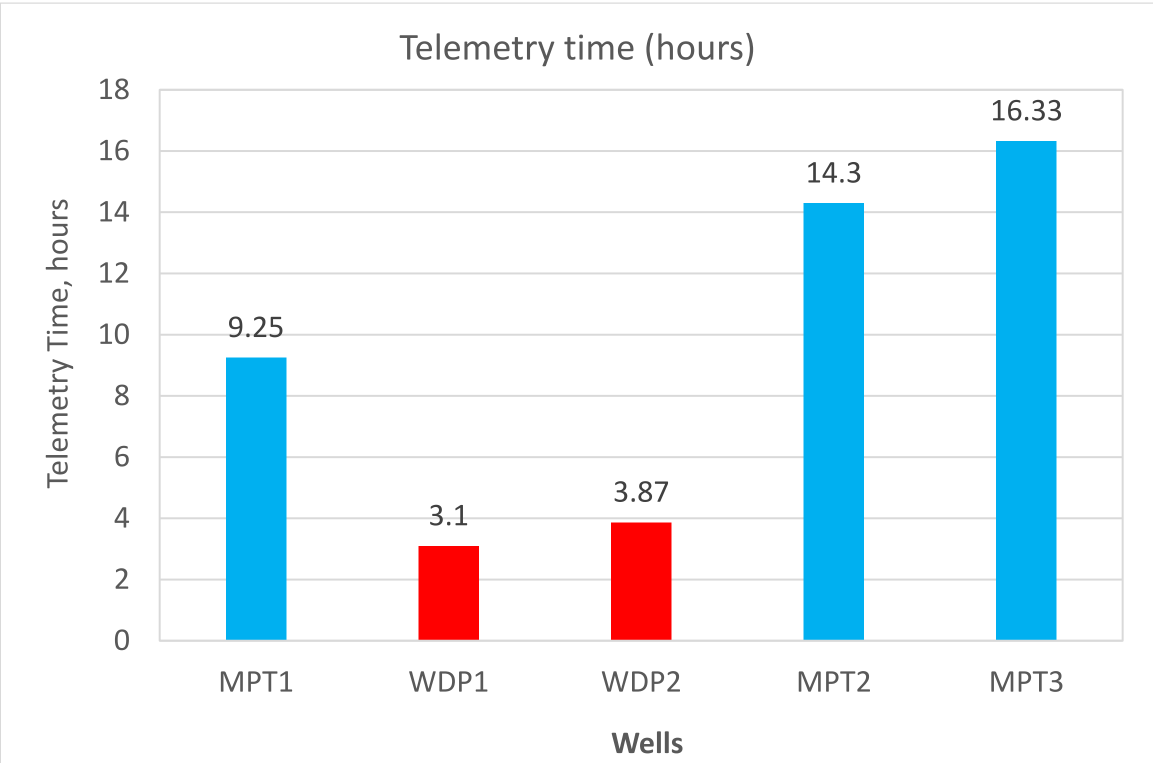

Figure 3.2. : Actual telemetry (hours per well) for 8.5'' and 6'' sections (Teelken et al., 2016)

From the graph, we can pinpoint the fact that for both the wells that used WDP, less time was spent as compared to the wells that used MPT. Generally, based on the theory the telemetry time should be close enough to zero for WDP. However, in this field, it could not be achieved due to two main reasons:

- Some tools in the BHA used in these WDP wells required off bottom downlinks to transmit data to the downhole tools.
- Also, the backup MPT system along with time spent on shallow hole tests consumed high time

Since the telemetry time depends on the length of the section drilled, it had to be normalized. As shown in the graph below,

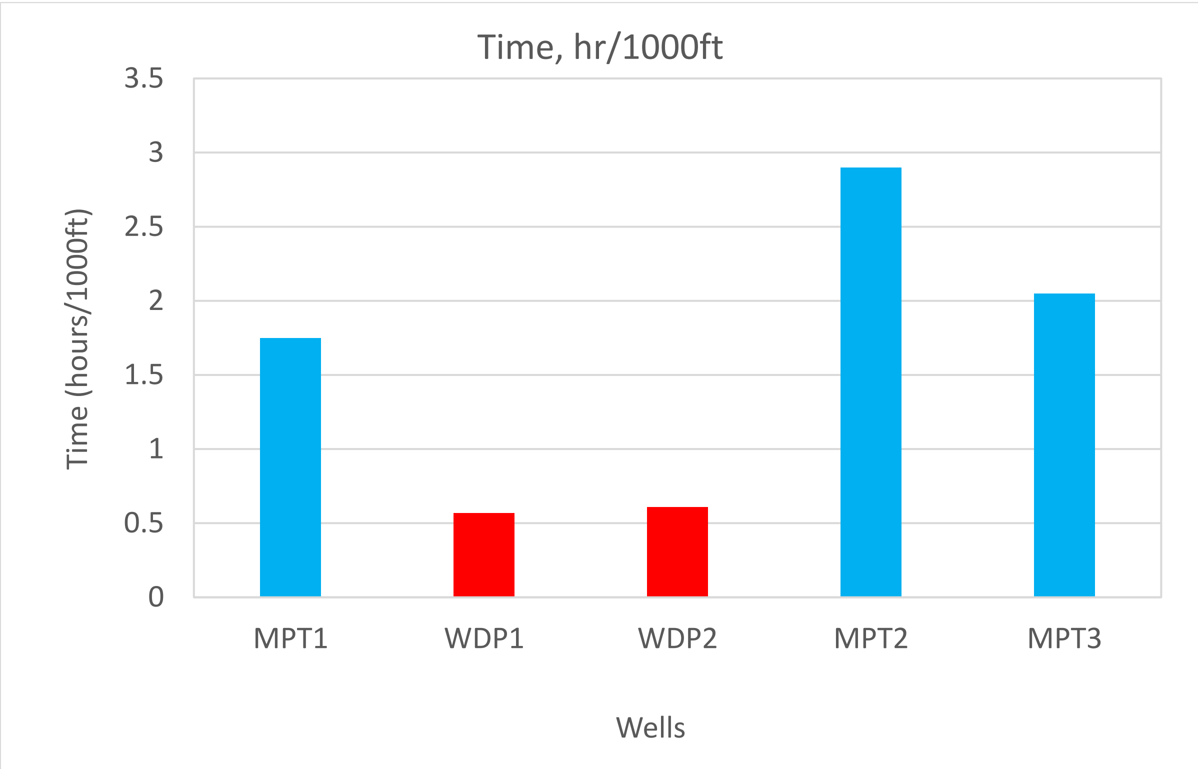

Figure 3.3. Normalized telemetry(hours/1000ft) per well drilled 8.5'' and 6'' section (Teelken et al., 2016)

For each well this could be done by calculating the time /1000 feet:

- the complete drilled footage for the three wells using MPT was 19, 251 foot. From figure above, the total telemetry time for these wells account to 39,88 hours.
- the mean normalized time found for wells that used MPT = *2.2 hours/ 1000ft drilled*
- the complete drilled footage for the two wells using WDP was 11, 269 foot. Again, the total telemetry time for WDP wells account to 6,97 hours
- the mean normalized time found for wells that used WDP = *0.59 hours/ 1000ft drilled*

Based on the corresponding activities in the well, the total related telemetry time was received from rig site. There is no requirement for any interpretation to understand telemetry savings received from rigsite as shown below in table 3.2. This involves only the faster data transmission.

Activity	WDP Time Saved (mins)	Number (Per Well)	Sub Total (hours)
Gyro/MWD Survey *	10	7	1.2
MWD Survey (Connections)	3	160	8.0
Survey (Check/Mid Stand)	8	22	2.9
RSS Downlink (off bottom)	5	45	3.8
Slide Orientation	5	45	3.8
FIT/ LOT Data Transmission	15	4	1
LWD Downloads	30	4	2.0
Total			25.9

Table 3.2. Overview of the telemetry times with the corresponding activities. (Teelken et al., 2016)

*****Wellsite comment: MWD surveys required two attempts for a good survey using MPT

2. Frequency of unexpected BHA trips

WDP telemetry has allowed early detection of drilling dysfunctions allowing a fast corrective action. The all-time improved reaction and mitigation towards the vibration and shocks have increased the life of bit and other sensitive downhole tools. Undoubtedly, this has resulted in lesser no of bit/BHA trips. (Solem, 2015)

In the drilling phase of the Babbage field development project, six tool failures were reported during drilling of all the six section with MPT i.e. each section experienced one failure.

> - Based on the received data, 186.5 hours of NPT was reported due tool failure alone i.e. a mean of 31.1 hours was lost each trip.

WDP faced only one tool failure in the complete four sections that was drilled. This was record decrease in the number of tool failures.

Figure 3.4 displays the footage drilled and the number of runs in the final two sections of all wells.

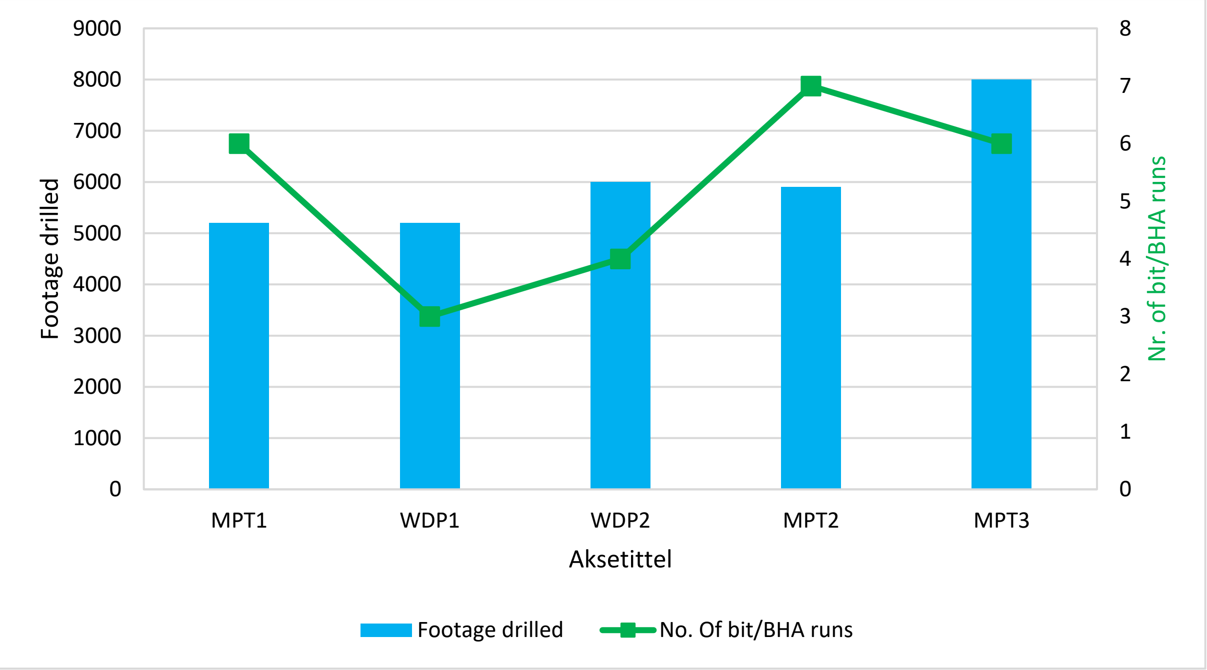

Figure 3.4. Number of BHA runs to TD (Teelken et al., 2016)

It clearly shows for drilling 5000ft standard well:

> - The mean WDP wells only needed three runs to TD is lower than the mean MPT wells. This significant reduction was due to the limiting of tool failures using WDP

3. Drilling time: on- bottom

An increase from 200% to 300% in ROP was experienced when compared to the offset well that was drilled with MPT. This increase in the drilling performance could be imputed to the performance of WDP system.

Abnormal fluctuations in the downhole pressure was experienced while sending the RSS/LWD downlinks in the MPT system. Along with it, ROP was limited while running superior LWD tools.

Figure 3.5 shows the ROP for the various wells in the Babbage development project and the corresponding telemetry used. From similar wells, offset wells were selected.

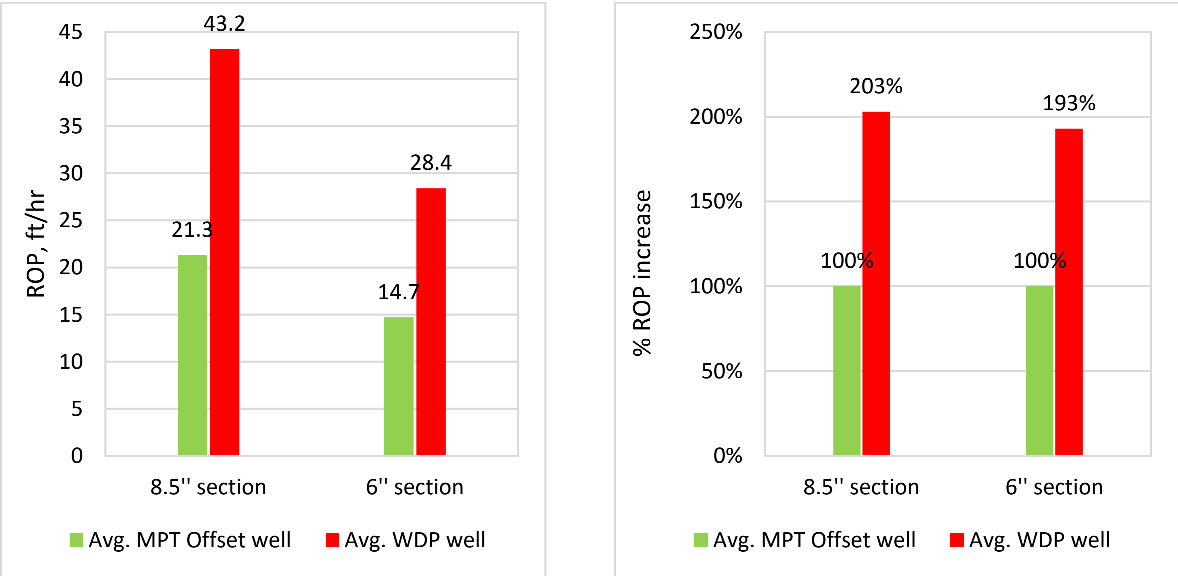

Figure 3.5. Comparison of ROP in each hole section(Teelken et al., 2016)

From the graph, the average ROP on WDP was achieved to be almost 203% higher than the average ROP on wells with MPT. To achieve the maximum ROP in the 6" section, the WDP system enabled the usage of an extra mud motor along with the RSS tool. The WDP wells achieved 193% more ROP efficiency when compared to that of MPT system.

Problem with MPT:
MPT system could damage the formation while drilling in a narrow pressure window. Also, there is possibility not achieving a constant WOB while downlinking during drilling.
Solution with WDP:
The important aspect of WDP system that was learnt during the drilling operation was improving the performance limiters (LWD density, shock & vibration, directional control) through proper ECD management and hole cleaning. This fundamental could be studied to other well operations such as lower completions/ re- completion activities that uses drill pipe.

4. Other Methods to improve efficiency:

A data driven approach for hole cleaning is established. The use of along-string (internal and annular) temperature and pressure measurements (ASM)have resulted in a remarkable hole cleaning optimization. In MPT operations, generally the mean off-bottom circulation hours for well cleaning could take several hours.(NOV for Total E&P)

Results:

- Improved well placement and ideal trajectory control by WDP system.
- Better understanding of the bottom hole drilling environment through real-time image of LWD logs.
- Tripping time reduction.
- Less tool failures with WDP system.

3.2 Martin Linge Field

Martin Linge Field situated in the North Sea of the Norwegian sector consists of shallow oil reservoir and various complex and high-pressure gas reservoir. The discovery of the field was in 1975. However due to the complexity, it was not developed until recently. Drilling in the environment created many challenges such as excessive downhole vibration and shocks, unstable formation, influxes and severe losses which resulted in poor LWD/MWD signals. Due to the limited bandwidth of the MPT, the real-time data signal is highly affected under severe conditions (Solem, 2015).

For instance, in case of adverse shock and vibration/ any unfavorable mud circumstances, difficulty of decoding the signals arise since the data transmission to the surface is interrupted. From the beginning WDP system was implemented on Martin Linge Project. Although the initial cost of the project was high, yet the potential effects of WDP system on the drains drilled was identified.

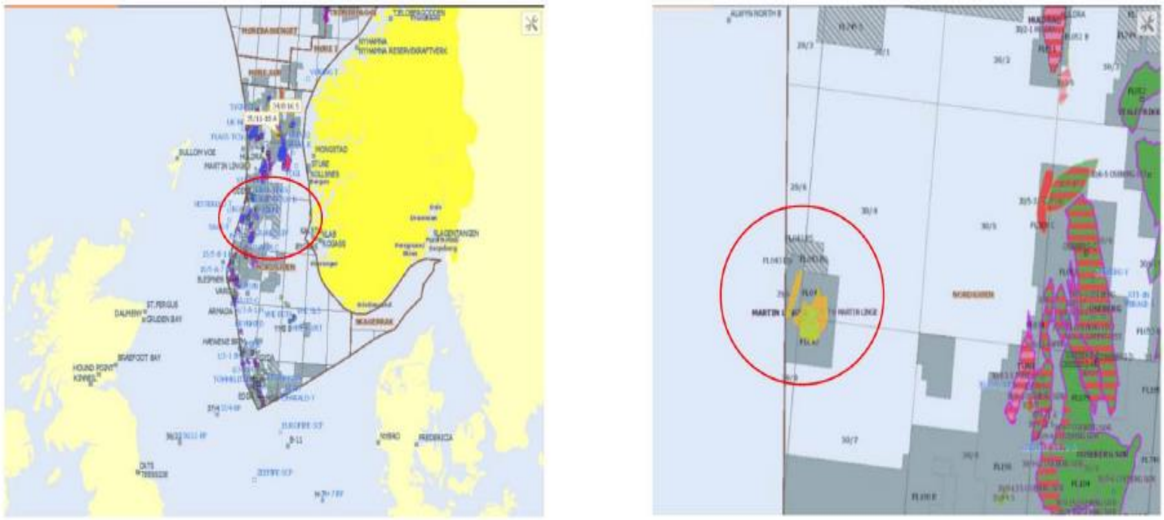

Figure 3.6. Location of Martin Linge field in the North Sea (MartinLingeLocation)

<u>WDP implementation system</u>:

Installation of WDP at the start of the project consumed some of the rig time i.e. rig configuration (surface cabling and top drive modification). WDP was utilized in the final two sections (12 ¼” and 8 ½ “section). An important application of WDP in this field was the activation of dual reamers (near bit and main). Hence the additional trip for opening the rat hole was avoided. This will be discussed in detail under the section Novel Application of WDP.(Schils et al., 2016)

Along-String Measurements:

ASM delivered real time data in case of critical events such as downhole losses and stuck pipe. Also, without the presence of MWD tool in the hole, the confirmation of mud weight and its behavior could be interpreted using ASM. The ASM data was used to monitor the ECD close to the shoe and behind the BHA in MPD operations. This ECD data based on the ASM helped in the reduction of hole cleaning time. Also, the results of the formation pressure test were received instantaneously at the surface using WDP system. (Measurement, March 8, 2017.; Solem, 2015)

Results in the field:

The telemetry time for the downhole data transmission was found. The data of the offset wells that utilized MPT system were compared with the wells that were drilled with WDP. The results of WDP operation shows the time for each survey before connection. The telemetry time for the 5 wells drilled with WDP was found. All the five wells had 4 sections (26", 17 ½", 12 ¼" and 8 ½") and the corresponding telemetry time is shown Figure 3.7. This is compared with the time logs from offset wells drilled with MPT system.

From the figure 3.7, the quantified telemetry time (mean) per well:

- The mean telemetry time for the two MPT wells: 24.53 hours/ well
- The mean telemetry time for the five WDP wells: 6.82 hours/ well

Thus, it can be inferred that 72% reduction in telemetry time with WDP was observed per well. Although most wells had a similar well profile, one of them required side tracking. Hence, there was requirement to normalize the telemetry values. The normalized telemetry time per well is shown in figure 3.8.

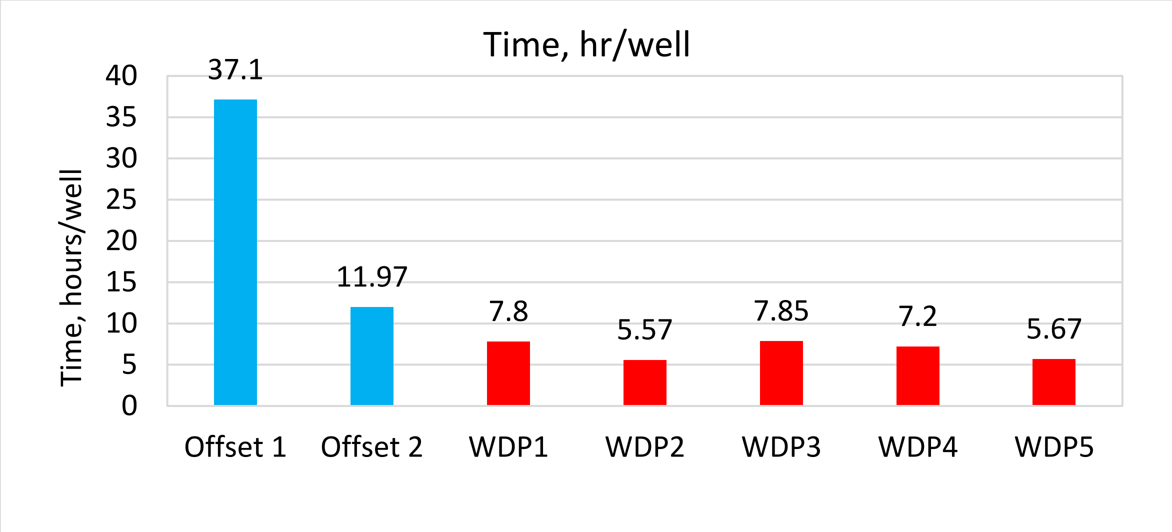

Figure 3.7. Telemetry time per well – Quantified (Schils et al., 2016)

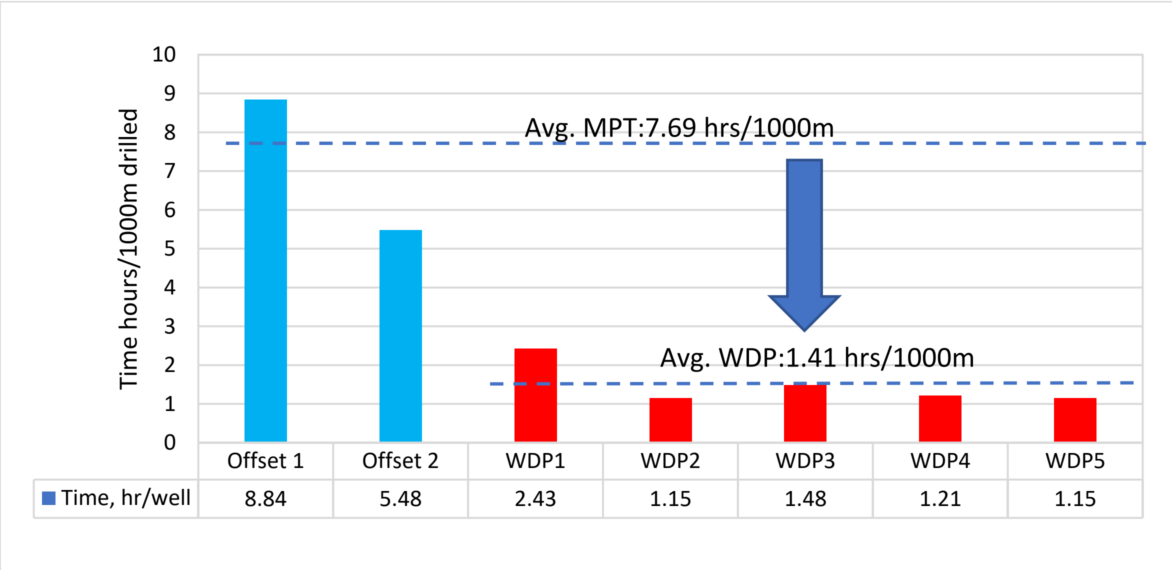

Figure 3.8. Telemetry time per well – Normalized (Schils et al., 2016)

- The mean telemetry time (normalized) for the two MPT wells: 7.69 hours/ 1000m
- The mean telemetry time (normalized) for the five WDP wells: 1.41 hours/ 1000m

Thus, it can be inferred that 82% reduction in normalized telemetry time with WDP was observed per well. Hence the time saved with the usage of WDP for transferring critical data between the surface and the downhole is estimated to be 6.28 hours for 1000m drilled (from figure 3.8).

Drilling Performance:

The complex pressure regimes below the 20” section shoe and the fragile sandstone formation in the reservoir section created hole cleaning challenges. Drilling the reservoir section mostly used WDP network. For the offset well, the 12 1/4” vertical section was drilled to almost 168m with 7.8 m/hour ROP whereas the reservoir section was drilled 55m with average ROP of 12.8 m/hour. From the hole opening runs and coring the reservoir section, the benchmark ROP for the offset well was defined to 8.6 m/ hour. The below graph 3.9 shows the ROP vs distance drilled:

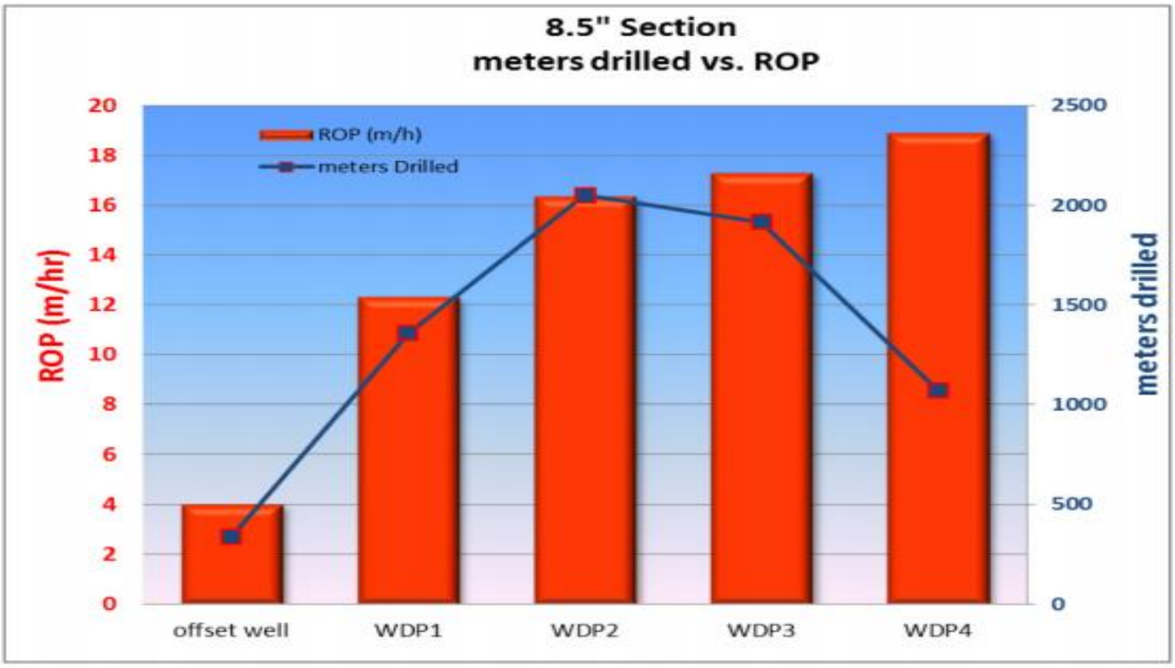

Figure 3.9. ROP vs meters drilled (reservoir section greater than 100m) (Schils et al., 2016)

The WDP system provided stable and improved performance while drilling the reservoir section. For obtaining the best comparison, the wells with reservoir section extending more than 100 meters were taken into consideration. Table 3.3 presents the footage and ROP for the reservoir section that was drilled.

Wells	Telemetry system	Hole Section	Distance drilled	Avg. ROP	On bottom drilling hours per 1000m	Difference in drilling hours per 1000m	Comments
		inch	meters	m/hr	hrs/1000m	hrs/1000m	
MPT Well 1:	Mud Pulse	8.5 coring + 8.5 x 12.25	223	8.6	116.3	0	55m of 8.5" coring + 168m hole opening
WDP Well 1	WDP	8.5	1357	12.3	81.3		8.5" drilling / geosteering
WDP Well 2	WDP	8.5	2049	16.4	61.0		8.5" drilling / geosteering
WDP Well 3	WDP	8.5	1916	17.3	57.8		8.5" drilling / geosteering
WDP Well 4	WDP	8.5	1070.5	18.9	52.9		8.5" drilling / geosteering
Avg. WDP Well	**WDP**	**8.5**	**1600**	**14.7**	**68.0**	**48.3**	**Potential time savings: 2 days**

Table 3.3. Distance drilled and ROP for WDP vs MPT reservoir sections (Schils et al., 2016)

Due to the formation weakness and hole dynamics, the maximum allowed ROP constraint was given to be 20m/hour. However, for the wells that are to be drilled in the future with WDP, this ROP constraint could be increased. The above table provides an overview of the ROP achieved in the drain section along with the time saving of almost two days for 1000 meter drilled. (Schils et al., 2016)

Novel Application of WDP system implemented in the field:

An important concept that evolved during the WDP operation was the need to develop downhole equipment that was compactable with WDP. Only this progress could maximize the utilization of this technology. The two new applications that were used in Martin Linge Field for the first time was:

- ***Integrated Reamer Activation (IRA):***

The IRA was installed in the downhole BHA. This could be controlled and monitored from the surface in real-time. In general, all reamers use MPT to activate and de-activate. However, the disadvantage of MPT system is that it consumes time and mostly generates fluctuations in downhole pressures. However, the ability of WDP system to integrate the reamer technology was met with success. Martin Linge field being complex drilling environment along with tight pressure window required this technology. Upgradation of the software was carried out for receiving signals up as well as downhole using WDP. This upgraded reamer system helped in saving rig time by using WDP to activate and de-activate the reamer. The reamer sends back the real-time feedback such as stick slip and tool vibration data. This real-time feedback has reduced uncertainty in operations while reaming. The innovation in this reaming operation with WDP has boosted demand of WDP. Martin Linge field used the first hole opener to operate via downlink i.e. The reamer is activated electrically, and operators could communicate from anywhere. The real time data on oil temperature and pressure, vibrations are transmitted to surface. This provides the operators instantaneous confirmation whether the hole is reamed with fully extended blades.

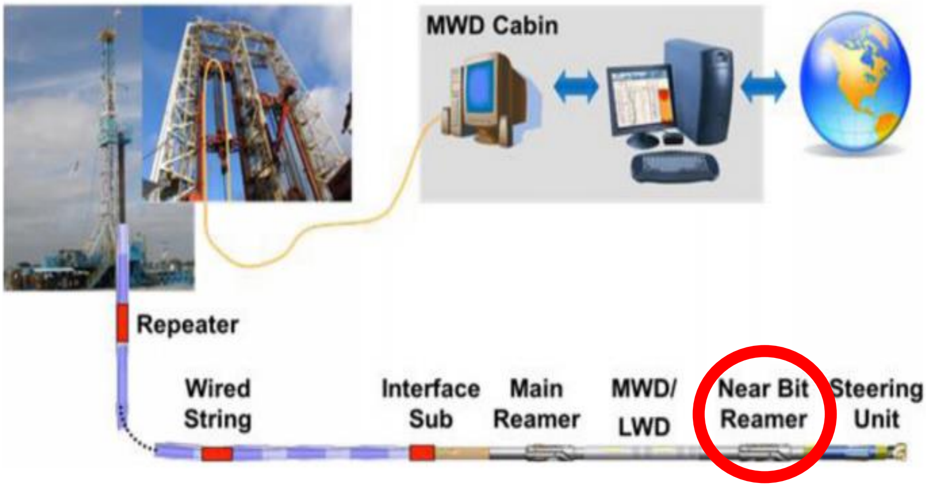

Figure 3.10. Schematic of Integrated reamer activated with WDP (Schils et al., 2016)

Result:

Since no mud pulse downlink was used, three minutes was saved per downlink. Also, after sending the downlink, the confirmation of the correct reamer signal was achieved instantaneously at the surface. This saved another three minutes per confirmation. Hence, overall the digital reamer saved a minimum six minutes per activation or de-activation of reamer. The POOH was made easier by the main reamer and the extra run to open the rat hole was eliminated by the near bit reamer. This was the first time that the controlling and activation of the reamer was carried out with WDP. The figure below illustrates the integrated dual reamer activated on WDP. (Grymalyuk, Schimanski, & Lilledal, 2016; Schils et al., 2016)

- **<u>Seismic While Drilling:</u>**

An improved tool to read the seismic data ahead was introduced that did not require mud pulse telemetry to take seismic shots. This saved three minutes for every seismic shot. Overall the wired drill pipe system enabled the detection of the reservoir formation ahead of the bit. The tool detected pertinent formation almost 200 mTVD in real time. This use of WDP system along with LWD gathered more reservoir length i.e. 1000 meters with the sand exposure increase to a mean value of 81% from the actual anticipated value of 67%. (Grymalyuk et al., 2016; Schils et al., 2016)

3.3 North West Shelf- Australia

A shallow mature field required side tracking out of the existing wellbore. For reaching the target reservoir, casing windows had to be cut at shallow depths. This created high doglegs. In most of the side track operations, the surface display showed lateral vibrations and pipe whip. However, the data from downhole dynamic tools/ MWD tools demonstrated no activity issues. The concern was that the drill string fatigue or casing wear that could occur due to the abnormal energy demonstrated by the moment of drill pipe at the surface.

<u>Process of Study</u>:

DDRs (downhole dynamic recorders) were placed throughout the length of the drill string as shown in the BHA below. This was the only means to analyze the drilling dynamics for different positions in the drill string.

BHA: Rotary Steerable / Geosteering						
#	Description	Max OD (in)	OD (in)	ID (in)	Length (m)	Total Length (m)
1	PDC 716 Bit	8.5	5.8	2.3	0.2	0.2
2	Rotary Steerable tool	8.4	6.9	4.2	4.9	5.2
3	LWD	6.8	6.8	2.5	38.0	43.2
4	Pony NMDC	7.5	6.8	3.8	4.4	47.6
5	Under Reamer	9.0	8.1	2.8	4.2	51.8
6	DDR BHA	6.8	6.8	2.3	1.2	53.0
7	HWDP	6.5	5.0	3.0	9.3	62.3
8	8.25" stab	8.3	6.8	2.9	1.9	64.2
9	2xHWDP	6.5	5.0	3.0	18.9	83.1
10	Jar	6.6	6.6	2.5	9.2	92.3
11	2xHWDP	6.5	5.0	3.0	18.8	111.1
12	DDR	6.8	6.8	2.3	1.2	112.4
13	DP	6.6	4.9	4.3	1898.0	2010.4
14	DDR	6.8	6.8	2.3	1.2	2011.6
15	DP	6.6	4.9	4.3	690.0	2701.6
16	DDR	6.8	6.8	2.3	1.2	2702.8
17	DP to surface	6.6	4.9	4.3		

Table 3.4. Position of DDRs in the geosteering BHA (Cardy et al., 2016)

DDR provided data to be analyzed post operations by merging with the surface parameter data. Torque and drag analysis and FEA (Finite Element Analysis) were carried out for calculating the natural frequencies along the string and for understanding the side forces.

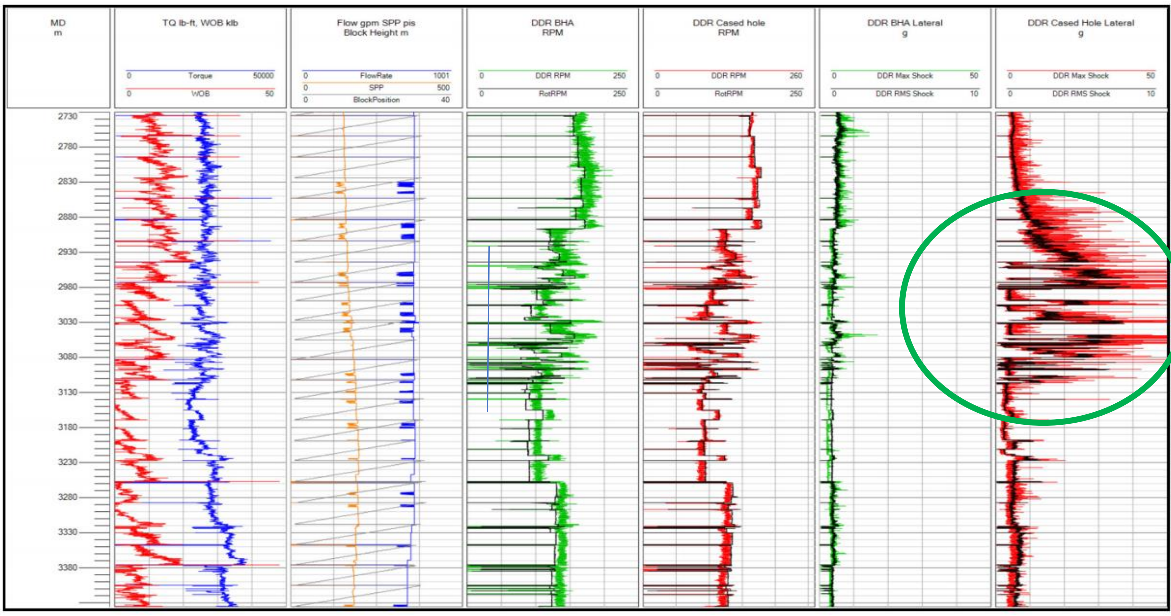

Figure 3.11. Depth log showing high lateral vibration in cased hole (Cardy et al., 2016)

Results: For studying the abnormal vibrations, the drill string system and the BHA was modelled in FEA. The results showed that the natural frequencies in the in the drill string were close to operational RPMs used while drilling. From the analysis result, figure is presented below.

Drill pipe

Natural Frequencies

Mode	Hz	RPM	Description
10	1.14555	68.73299	Lateral
11	1.14555	68.73299	Lateral
12	1.171281	70.27686	Lateral
13	1.171281	70.27686	Lateral
14	1.489838	89.39026	Axial
15	1.502563	90.15376	Lateral
16	1.502565	90.15388	Lateral
17	1.904817	114.289	Lateral
18	1.904818	114.2891	Lateral
19	2.453548	147.2129	Lateral
20	2.453581	147.2149	Lateral
21	2.523217	151.393	Torsion
22	3.028383	181.703	Lateral
23	3.028415	181.7049	Lateral
24	3.253058	195.1835	Lateral
25	3.253058	195.1835	Lateral
26	3.291871	197.5122	Lateral

Figure 3.12. FEA analysis(Cardy et al., 2016)

- Lateral natural frequency = 147.21 hz
- Operational RPM ranges between 125 to 160 from the depth-based log

It is also evident from the depth-based log that a co-relation exists between the lateral vibration and the weight of bit. The vibration shoots up as the applied WOB increased. From, initial understanding, this could be due to the decrease in tension along the drill pipe across a section. The decrease in the tension might cause the pipe to resonate when the natural frequency of the drill pipe reaches that frequency of the rotary speed (Cardy et al., 2016).

Summary/ Problem:

Any string vibration depends on the rotary speed and WOB along with the contact forces generated at the point between casing and the drill string. For any side tracks in future wells, these parameters need to be considered for planning well profile. The example above demonstrates the dynamic regimes, potential damage and high energy that could occur in the upper part of the drill string. In this case the dysfunctions are evident at the surface. Another important area to understand is that the plot and logs display the lateral vibrations of a certain period. All drill pipe that passes through this section is subjected to the lateral vibrations. The operation used data only from the memory tools which could be retrieved only after the operation. Hence the data received did not help in solving any dysfunctions related to drilling dynamics and in optimizing the live well operations

Solution:

The solution is to use ASM along the length of the drill string which will enable the transmission of real time vibrational data with WDP. This helps the drilling team to observe the drilling dynamics and control the drilling parameters to mitigate any unwanted vibration in the drill string.

3.4 Field Trials– Middle East

A field trial with three phase approach was carried out in Middle East to study how WDP could customize to adapt harsh and risky drilling environment.

Phase 1: System Integrity and Functionality

The objective of phase one was to understand and ensure the system functions at wellsite within the specific / required downhole conditions. When compared to logs received from the mud column, high density LWD logs could be received in real time with high ROP rates using WDPT. This is because WDPT allows faster telemetry without any restrictions in the data points signaled to the surface as shown in section 2.3.3(Sehsah et al., 2017). Most wells face issues due to swab and surge. Improper planning along with calculation uncertainties or unexpected downhole conditions often result in problems related to losses or influx leading to wellbore instability (Mehrabian, Jamison, & Teodorescu, 2015).

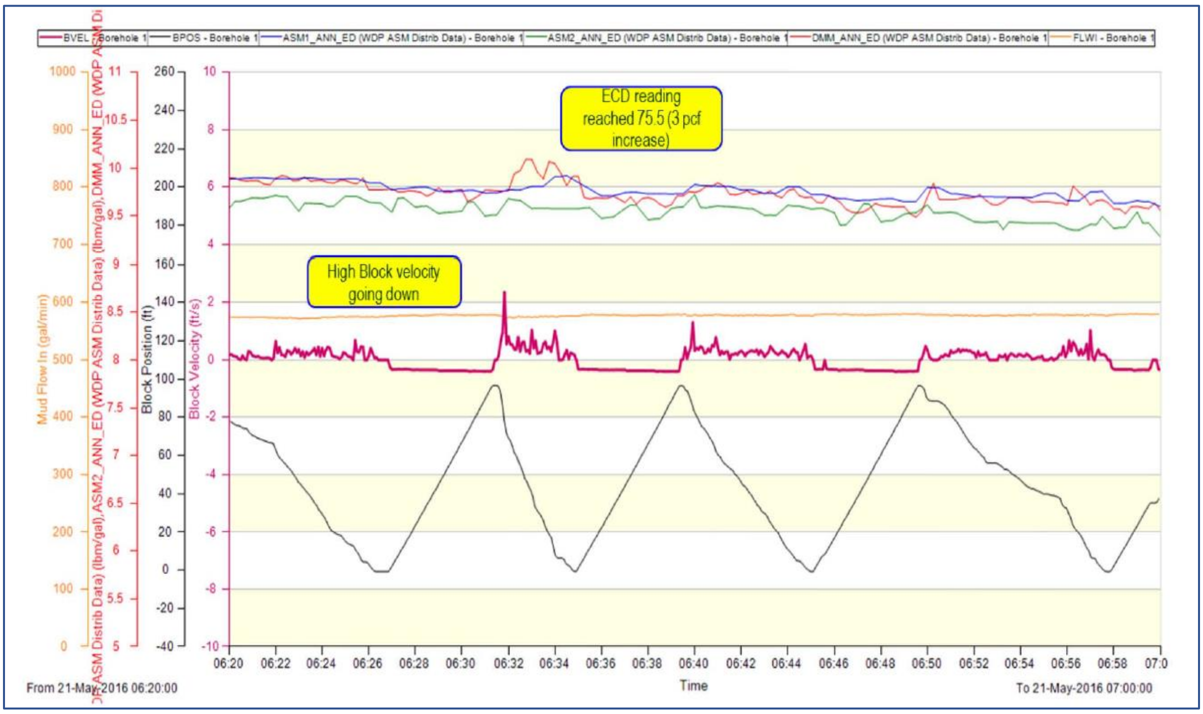

Figure 3.13. Surge incident due to high block velocity. (Sehsah et al., 2017)

The graph above is from one of the trial wells. The green, red and the blue curves indicate the ECD, the black curve shows the block position, and the magenta curve is block velocity. The operation is tripping after circulation. The fast pipe movement (increased block velocity) resulted in surge scenario. It can be spotted from graph that the red curve surged by 3 lb/ft^3 and the incident took shorter than two minutes i.e. between 6:32 and 6:34. WDP allowed faster detection of the event. In MPT systems, the pressure data gets updated only by 4 to 5 minutes. In that case such short events could be easily misinterpreted or missed.

Phase 2: ASM assisted top of mud measurements

Based on the pressure measurements from ASMs, top of mud algorithm was designed to be calculated accurately. With WDP, there is a possibility to place pressure sensors (ASM) along the string. This led to the option to calculate the ESD/ECD based on the depth difference (TVD) between the sensors. This gives an enhanced image of the zones between the sensors. The length between the sensors will determine the quality of the image. It is apparent that placement of the ASMs as close as possible will improve the quality of the image. Based on the zone of interest the position and the distance of the ASM should be planned(Sehsah et al., 2017).

Phase 3: Early kick detection

One of the key characteristics in WDP system is the ability to sense kick detection. A possibility to detect kicks in situations where there is a complete loss circulation along with systematically tracking the circulation of kick out of hole is an added advantage. A gas influx creates a drop-in annulus pressure. This decrease in pressure is determined based on the density contrast between gas and mud. A small decrease of annulus pressure might not be detectable with normal pressure measurements in the annulus. However, using interval density measurements can detect this pressure drop because it is calculated depending on the distance between the ASMs. Hence spacing of the ASMs along the drillstring provides means to determine early kick/influx. To note, the length between the ASMs should be set on the density contrast between the formation fluid and mud(Sehsah et al., 2017; D. Veeningen, 2013).

Inferred applications:

- **Estimation of mud level in annulus**

WDP technology helps in locating a thief zone and early detection of kick when the level of fluid in the annulus rise. Consider an operation, drilling or workover where there is a total loss of fluid into the formation. This is termed “blind drilling” where there is no fluid return to surface. WDP will be an application for risk management since it provides full sight of downhole condition. Positioning ASMs at different depths in the drillstring provide means to detect downhole kicks and blowouts and estimate the level of fluid(D. Veeningen, 2013).

- **Continuous monitoring of BHP**

Swab and surge effects the drilling operations by disturbing the BHP. The ability to receive high frequency measurement of the BHP along with the potential to continuously maintain the downhole pressure within the density window (pore pressure and fracture pressure) is the key feature of WDP technology (Sehsah et al., 2017; Solem, 2015).

3.5 Troll Field-Norway

Troll field with approximately an area of 770 km^2 forms one of the largest oil field in NCS. It is in Norwegian North Sea, nearly 80Km northwest of Bergen.

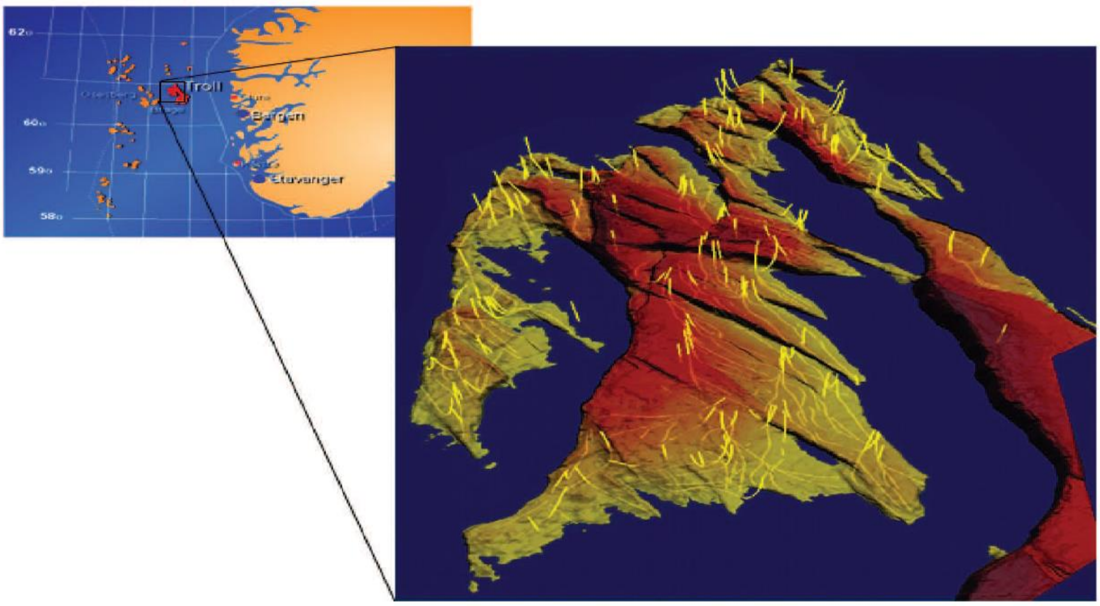

Figure 3.14. An overview of Troll West field (Nygard et al., 2008)

The presence of calcite stringers throughout the reservoirs created drilling issues in Troll field. The drilling bit could be pushed into more drillable formation when faced with calcite stingers.

As a result, high doglegs are created at certain intervals. Further, due to the bending related issues and the stress experienced in the BHA, there is always a possibility of fatigue. The magnitude of this fatigue conditions is influenced by the weight on the hookload. The presence of hard calcite often leads to decrease in ROP. For mitigating these issues, it is important to know the formation ahead while drilling(Denney, 2008).

At troll field, implementation of WDP system helped in identifying the calcite stinger in real time. Hence necessary mitigation actions such as instantaneously changing the RSS parameters helped in reducing the drilling time which otherwise was used to flatten out doglegs created by calcite formations. Also, bending related tool failures and the stress on the BHA was reduced after using WDP unlike other wells drilled in Troll field(Denney, 2008).

Figure 3.15. Challenging Hard calcite nodules in a relatively high-permeable sand in Troll field (Nygard et al., 2008)

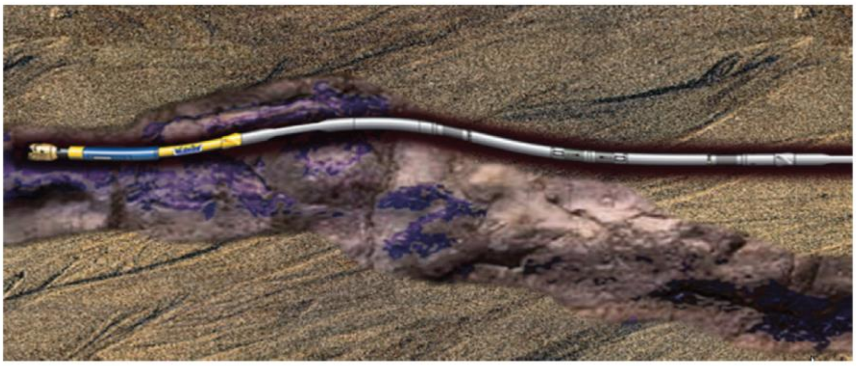

Figure 3.16. Artistic illustration of HLD developed at the surface of a calcite-cemented stringer (Nygard et al., 2008)

From this it was inferred that in fields where there could be a potential to have high dogleg while drilling, the real time parameters should be made available for identifying the hookload. Understanding the bending and drilling dynamics data help to instantaneously change the drilling parameters which aid to take required measures for reducing the identified hookload. A high rate of data telemetry i.e. WDP system is required to fulfill the above criteria for mitigating high doglegs(Nygard et al., 2008).

3.6 Occidental Petroleum-California

Elk hills field operated by Oxy petroleum is the fifth largest oil field in California. As per the annual report of California Department of Conservation (2006), a cumulative production close to 1.3 billion barrels was reported from this field (McCartney et al., 2009).

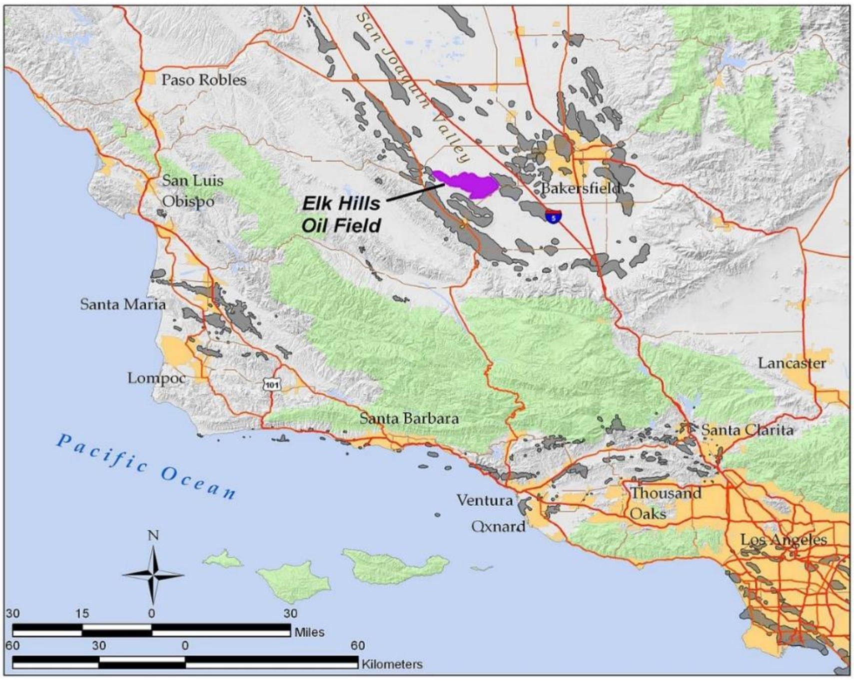

Figure 3.17. The Elk Hills Oil Field in California, (purple). Other oil fields are shown in gray.(McCartney et al., 2009)

Due to the presence of low permeability reservoir, it was a requirement to perform underbalanced drilling. Some of the crucial problems faced in the reservoir were pore pressure and ECD management issues. For mitigating this issue, it was decided to use foam as the drilling fluid to attain the needed pore pressure and ECD. In usual situations, foam proved to be inefficient and many times resulted in the BHA failures. This was due to the inability to receive continuous data due to the irregularity in the flow rate and density of foam. Uniform density of drilling fluid was required for the transmission of mud pulses at higher rate. While drilling, for MPT system the downlinking time along with the confirmation of tool activation was considerably higher. This resulted in a high NPT of nearly 10% to 12% of the overall time for drilling the well. Along with the above issues, stick-slip, shock and vibration were the other problems faced in this field. With MPT system, it was not possible to send all the data from the MWD tool at higher transmission rate to the surface for the real time interpretation. In some cases, an extra trip was required to retrieve the data from memory gauge that could not be transferred through MPT (McCartney et al., 2009).

This case studies are based on total of 17 wells of which five wells used 4" wired pipe and foam was used as the drilling fluid. A higher quality gamma ray images (spectral and azimuthal) were obtained using the wired pipe. A better well placement and transmission rate was achieved due to real time data transfer to surface. Real time log interpretation highly helped in understanding the formation being drilled. Figure 3.18 shown below is the log image obtained using WDP.

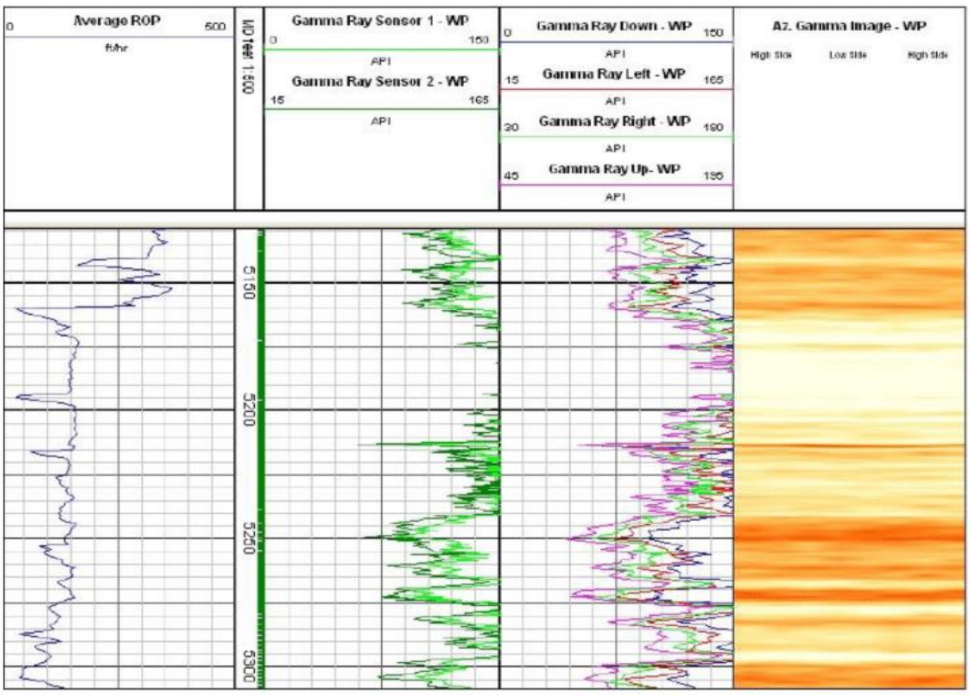

Figure 3.18. Log image using WDP (drilling fluid used is foam). (McCartney et al., 2009)

Along with providing bi-directional communication between surface equipment and bottom hole tools, a higher reduction in NPT was achieved in this field. The first two wells drilled with WDP saved almost 4 and 6.2 hours respectively.

	Well	No. of Downlinks	Downlink Time and conformation (hr:mm)	Time Saved (hr:mm)
25 bps Mud Pulse Telemetry	A	58	04:00	0
	B	71	04:15	0
	C	54	03:45	0
Wired Pipe Telemetry	1	50	N/A	04:02
	2	72	N/A	06:24
	3	62	N/A	04:00

Table 3.5. Downlink performance comparison of MPT to WDP for the project. (McCartney et al., 2009)

The logs below depict the vibrational data acquired during the operation. Figure 3.19 shows no damaging effects due to vibration. However, Figure 3.20, the second log, at certain intervals the vibration is very high

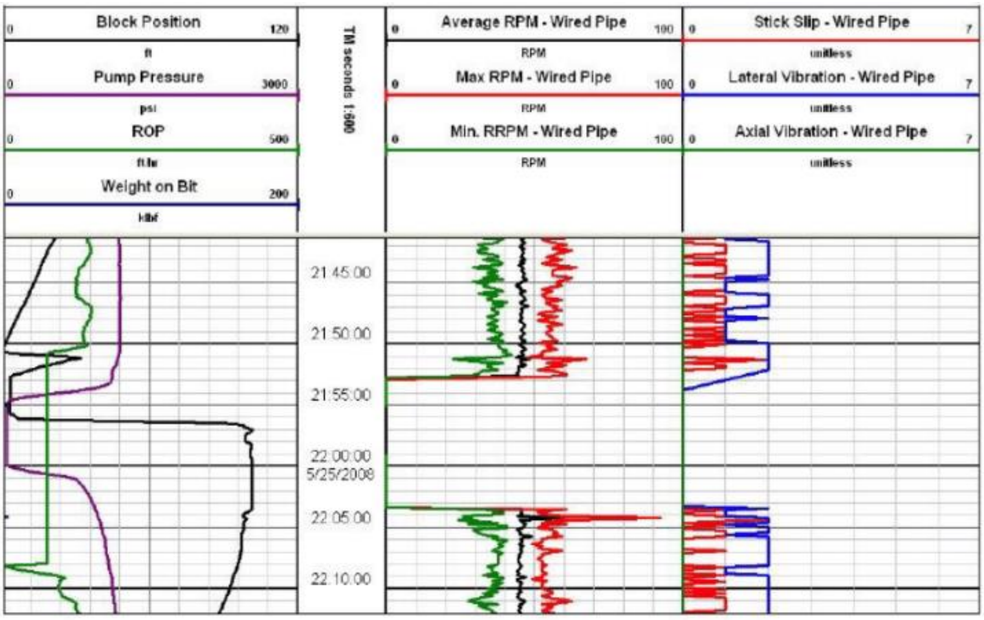

Figure 3.19. No vibrational issues in the above intervals(McCartney et al., 2009)

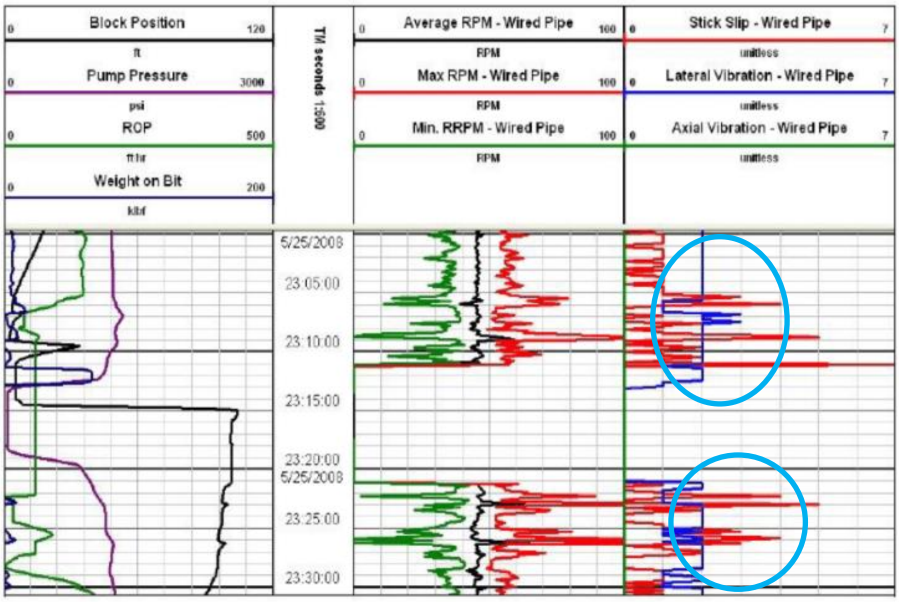

Figure 3.20. Clear indication of abnormal vibration in the intervals (23:05 to 23:14 and 23:22 to 23:26) (McCartney et al., 2009)

Figure 3.21 presents the comparison of both WDP and MPT system's data quality. As shown, the WDP provides higher resolution data which allows the well engineers to alter those parameters for reducing the vibration.

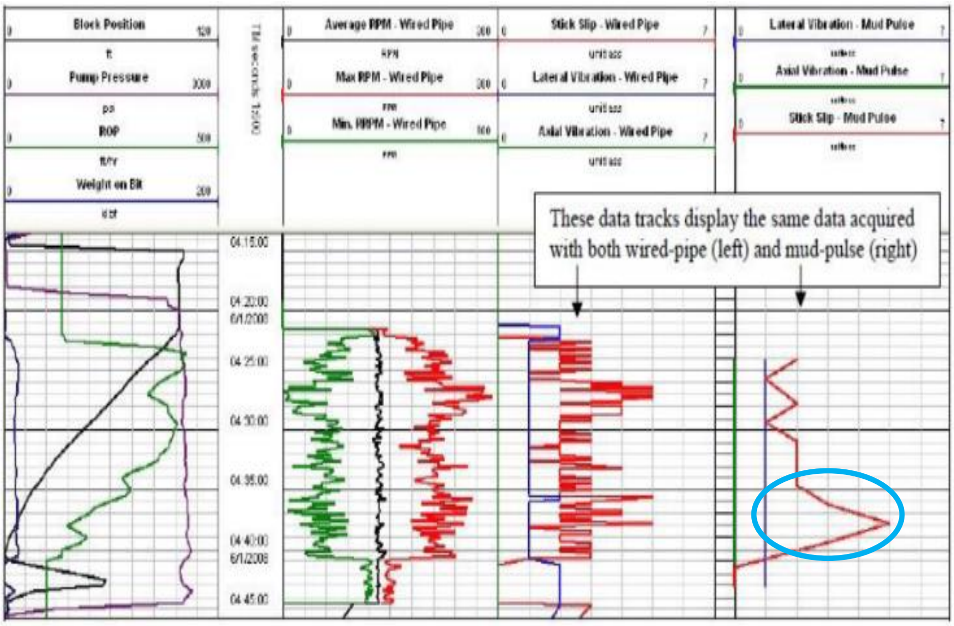

Figure 3.21. comparison of both WDP and MPT system. (McCartney et al., 2009)

Considering the lateral vibration in both the cases, the MPT depicts a straight line implying any unexpected changes in lateral vibrations are not registered with MPT while WDP depicts exact differences in lateral vibrations. The more precise data acquired from WDP helps in improving the drilling performance and creates a comprehensible real time view of the downhole dynamics.

As discussed earlier, due to the formation damage, this field had ECD management issues. Hence to accurately control ECD in real time, WDP was deployed. Figure 3.22 shows the the ECD measured by the ASM/ MWD tools were received at surface with higher resolution which assisted the drillers to geosteer within the pressure window which was modelled in real time.

In Elk hills field, WDP benefitted for underbalanced drilling with foam as drilling fluid in low permeability formations along with the reduction in drilling time by 10 % to 12 %.

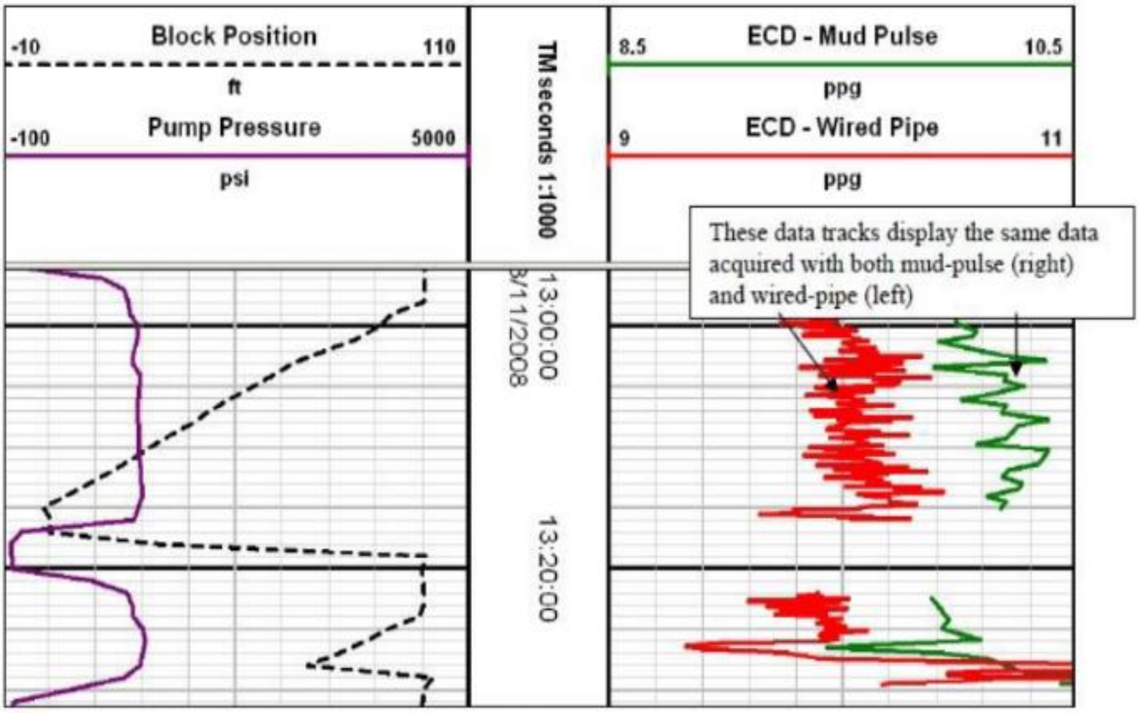

Figure 3.22. Accurate prediction of ECD by WDP (McCartney et al., 2009)

3.7 Trinidad Fields

Trinidad field is one of the largest proven oil field located in the Eastern Venezuelan Basin. Highly deviated wells (ERD) are drilled from a single fixed platform in offshore Trinidad fields. One of the key challenges was drilling the gas well with casing of 10 ¾" to the top of the reservoir with hole angle greater than 60°. The decision to drill with bigger casing was to have a higher production rate. An excessive wellbore instability was encountered while drilling softer formations. This led to tendency of wash out and other critical downhole dynamic problems such as stick-slip and whirl (Stephen T Edwards et al., 2013).

Figure 3.23. Islands in the sand stream: Trinidad and Tobago's oil economy.(SUKHU, 2017)

Along with acquiring real time images, WDP helped to identify and determine wellbore instability issues. All the logged data obtained by the LWD tool could be sent without any delay to the surface. WDP was deployed to re-drill a section after it was lost while drilling using MPT. Receiving the real time images enabled the drilling team to adjust mud weight as per the requirement to prevent the wellbore instability. LWD log received while re-drilling the lost section is shown Figure 3.24.

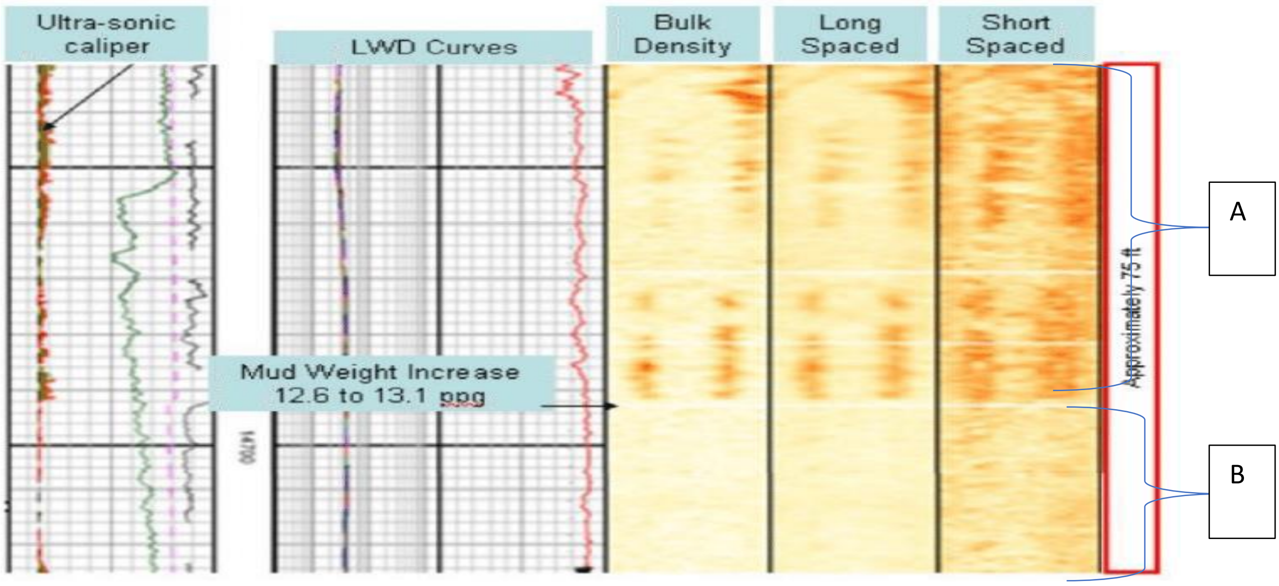

Figure 3.24. LWD log showing the MW increase from 12.6 to 13.1 ppg(Stephen T Edwards et al., 2013)

It is evident that the darker areas in the image display section with higher instability as shown in region labeled as (A). Moreover, at the same instant one can also observe higher value on the caliper log. As the mud weight was increased from 12.6 to 13.6 ppg, the well could deliver higher stability. As shown in the region (B), up on increasing the density, the dark image becomes lighter and the caliper log reduced to the normal size. This illustrates how real-time data add value to monitor the wellbore instability condition and allowing to take real-time remedial action before the condition the wellbore being deteriorated(Stephen T Edwards et al., 2013).

3.8 British Petroleum-Alaskan Field

To better the understanding of wired pipe, BP conducted several trial runs starting with the two wells in Wyoming, US. After the trial runs, BP commercialized the usage of wired pipe in 14 more wells in BP operational sites (deep-water GOM, North Sea).

Figure 3.25 is the Prudhoe Bay field, situated on the edge of the Arctic Circle, on the northern slope of Alaska. It was discovered in 1968 and was estimated to hold 22 to 25 billion barrels of oil in place. The production in the field began in 1977 and till today production has reached more than 12.5 billion barrels. The field has adopted wide range of progressive drilling technologies which includes coiled tubing and multilateral operations which is currently employed by oilfields across the globe. Moreover, this field has utilized the EOR technologies which are globally used now.

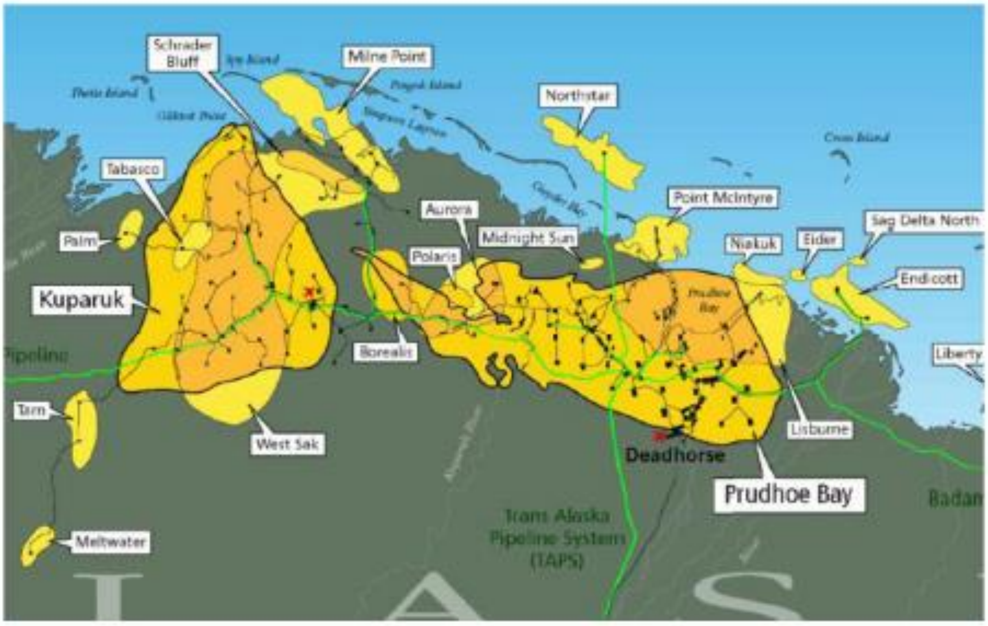

Figure 3.25. North Slope of Alaska Field Map.(Israel et al., 2018a)

Many drilling activities are ongoing to maintain production and BP has attempted several technologies to better the productivity of operations in this field. One such technology assessed in this field was the latest version of WDP along with the deployment of automation operating system (AOS). Figure 3.26 depicts the telemetry time saved by 6 wells in this field using the combination of WDP with AOS. Telemetry savings such as surveying and downlinking were optimized. Altogether almost 31.7 hours of telemetry time were saved with the operation in 6 wells.

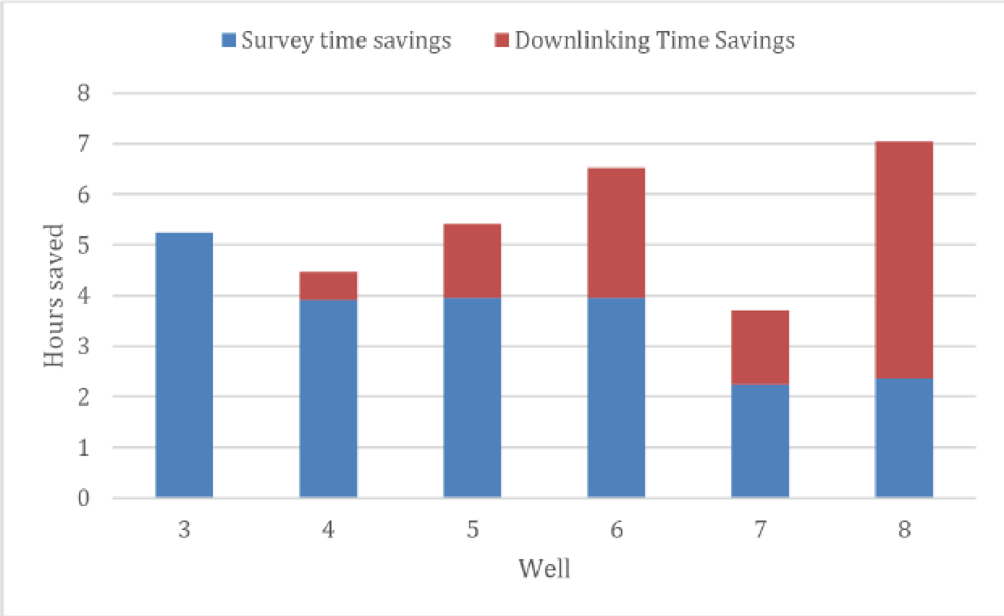

Figure 3.26. Estimated telemetry time saving by well.(Israel et al., 2018a)

Surveying: Since the field was in the far north with complex reservoir trajectory and collision possibility with nearby wells, it was required to carry out multiple surveys per stand which increased the usual wait time per stand using MPT. Although WDP follow similar process, yet the wait time to receive surveys are approximately only 20 seconds. It was found to save 2.5 to 3 minutes for each survey. When accounted, the combined effect for all the six wells was significant.

Downlinking: MPT generally consumes 10 to 15 minutes per downlink when performed off-bottom. However, with WDP the requirement for MPT to perform downlinking was eliminated. Further uninterrupted data transferred during downlinking operation to the surface eliminated the NPT caused due to data blackout during MPT downlinking(Israel et al., 2018a).

Operational issues faced by BP using WDP (first version V1):

Top drive modification is one of the most challenging issue in deployment of wired pipe since it accommodates the data swivel. The data swivel is installed at the bottom part of the top drive where the saver sub is present (Stephen T. Edwards et al., 2013). For BP, out of five trials across the globe 4 trials have been successful. Only North Sea project faced certain issues due to the usage of old pipe design. The present design of wired pipe uptimes 90 to 100 percent. As the equipment is used further, the reliability is reduced. The issue mostly faced are associated with connections.

- **Steel Flarels Corrosion:**

In NCS, the pipe joints initially used had been stored at workshops for long period. Flarel is the component fixed at the tool joint which provides connection between coil and the coaxial cable. This component was made of steel during the initial days of operation, and thus had corroded with time. Although the electrical conductivity test was positive at the surface, yet at certain depth the network completely lost connection and failed. This issue could not be identified at surface, hence troubleshooting the issue was difficult and resulted in ineffective operations. Later a thorough study was done and the steel flarels were removed from tool joints.

- **Over Torqued Connections:**

Due to the concern of contamination in completion fluid, dope was not used for connection make-ups. This made the string to over-torque and damage the milled groove where the coil is placed.

- **Pipe handling:**

Generally, pipes should follow good handling procedure for networked connections. A slight mechanical deformation will not make the normal drill pipe unusable. However, this action could lead to easy damage of electromagnetic coils present in every joint and the cable stretching inside the pipe, thus affecting the reliability of wired pipes. Proper stabbing should be followed while connection is made. Placing the pipes in stands is not convenient, so individual make up/ break out should be carried out at rig site. At present only reservoir section was drilled using WDP. Hence there is a requirement to keep both conventional and wired drill pipe on rig which is space consuming(Stephen T. Edwards et al., 2013).

3.9 Wiredpipe application in MPD/UBO environments

Drilling deep-water wells with conventional methods is a challenging operation since the drilling window could be narrow. Moreover, in depleted formation, the conventional drilling method results in well fracturing. For drilling in the narrow window and depleted formations, manage pressure drilling (MPD) and underbalanced operations (UBO) are the solutions, respectively. As David et al (2014) reported, the first version V1 WPD solved the challenges associated with MPD operations drilling "undrillable'' areas by providing a level of control back, which is not otherwise possible. Table 3.6 summarizes the eleven wells field case study of wiredpipe value contribution with regards to drilling faster, rig time saving, well placement/quality, risk reduction and reduce mud losses. (D. S. Pixton et al., 2014)

Campaign	# Wells	Total Ft Drilled	Downhole Sensors/Tools w/ High Speed Telemetry	Wired Drill Pipe Value Contribution	Reference[2]

Myanmar Offshore	1	1,260	Annular Pressure, Resistivity, Gamma Ray, Temperature, Direction and Inclination	• **Drilling Enabler:**
				  • High speed feedback loop mitigated high risk environment
				  • Telemetry available under no-flow and low-flow conditions
				  • Interactive communication with battery sub conserves power for critical operations
				• **Rig time savings:** Avoided trip by *in situ* MWD tool reprogram
					Fredericks et al. (2008)

Mexico Land	2	2,152	(Varied) RSS, Directional, Resistivity, Gamma Ray, Annular Pressure, Temperature	• **Drilling enabler:**
				  • No alternative means of obtaining real-time directional and pressure data in this ultra-depleted well
				  • Bottom hole and along string pressures enabled continual choke optimization to control pressure
				  • Along string measurements enabled detection of lost circulation and formation fluid influx
				• **Rig time savings:** Reduction in sidetracks
				• **Wellbore placement/quality:** Reduced dogleg severity
					Rasmus et al. (2013)

US Land	5	26,226	Gamma Ray, Annular and Bore Pressure, Directional	• **Risk reduction:** Visibility of well pressure during no flow and pump startup flow conditions • **Wellbore placement/quality:** Directional control in foam environment	Allen et al. (2009)

US Land	3	15,093	Directional	• **Reduced mud losses:** Telemetry independent of mud type enabled use of nitrified mud and ultimately aggressive use of lost circulation material to control mud loss
				• **Rig time savings:**
				  • Fast on-demand surveys, checkshots, and tool face updates
				  • Increased sliding drilling efficiency
					Melcher (2012)

Table 3.6. Summary of well campaigns using wired drill pipe in MPD/UBO environments (D. S. Pixton et al., 2014)

4 ALTERNATIVE APPLICATIONS OF WDP

4.1 Reason to use WDP for Equinor ASA assets

To prepare a world towards drilling automation and to be in line with the upstream corporate digitalization policy, Equinor ASA is enhancing the use of wired drill pipe to obtain real-time subsurface data throughout the drilling operations(ASA, 2018b; Jacobs, 2019).

This section will discuss Equinor ASA's reason for opting wired drill pipe with views on the performance of the pipe with the expectation (ASA, 2018b).

At present, it has been decided to use WDP for specific operations, such as Transocean Enabler's drilling campaign on Trestakk field, the West Herkules exploration campaign in Norwegian continental shelf and Mariner in the UK. In the future, however Equinor focus to expand the use of WDP in other well operations including drilling. The study below aims to benefit operations using WDP in Snore Expansion project (SEP) or other field developments in the future (ASA, 2018b; Project), 2019).

Optimizing the wellbore quality, reducing the NPT and overall cost savings were the major benefits that were the foremost considerations. In addition, considering the technical difficulties and the scope of field development, WDP was chosen to be the right choice (Fosse, 2015; Solem, 2015).

4.2 The Snorre expansion (SEP) project and WDP

Figure 4.1 shows the location of Snorre field, which is situated in the Norwegian Sea, in blocks 34/4 and 34/7. The water depth of the field varies between 295m and 380m. The hydrocarbon reserves are found in Triassic and Lower Jurassic sandstone complex faults structures of the Lunde formation and Statfjord Group. Historically, the reserve has been proven in 1979 and the development plan approved in 1988. Until the end of 2016, the field has produced 208 million (Sm^3) of oil, 9 million Sm^3 of natural gas liquids, and minor amounts of gas and condensate [Table 4.1]. Figure 4.2 show production since 1992 until 2018 (Directorate).

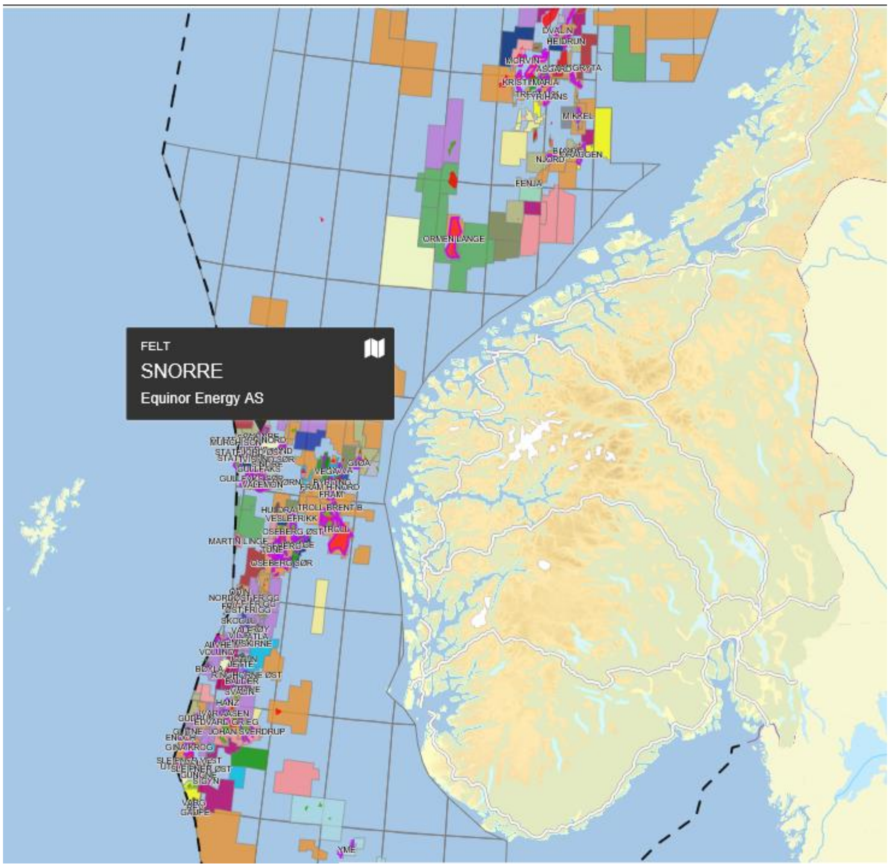

Figure 4.1. Snorre field location map (Directorate)

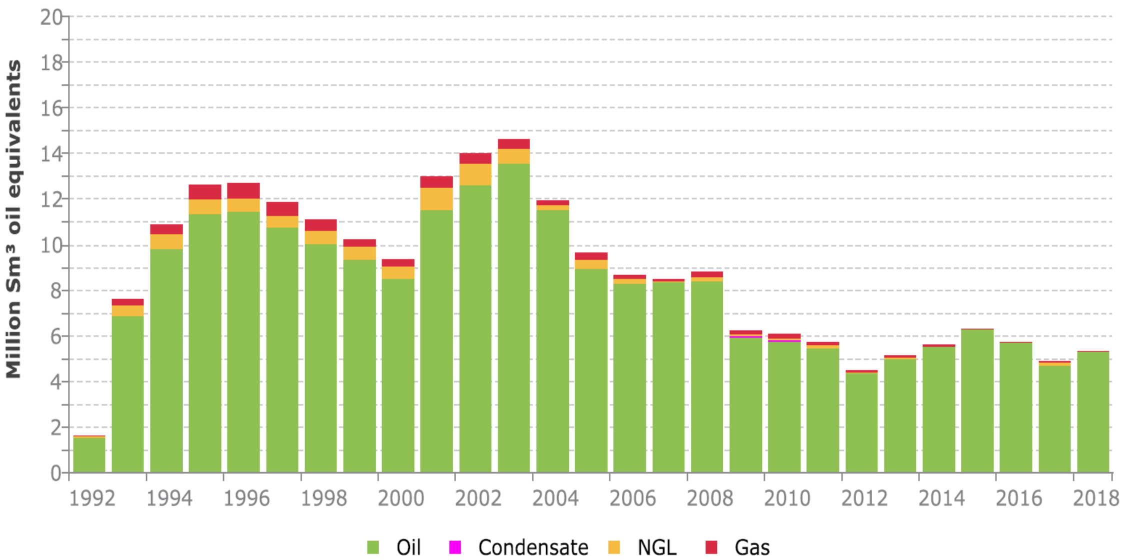

Figure 4.2. Snorre field hydrocarbon production history(Directorate)

Currently, the Norwegian Petroleum Directorate offered Equinor ASA for further use of Snorre A and Snorre B facilities in 2040 in order to recover remaining resources in the field, which is estimated to be 92 million cubic meters (590 million barrels).

	Oil	Gas	NGL	Condensate	Sum
Recoverable reserves originally	310.1	6.6	9.0	0.0	325.7
Remaining reserves	91.8	0.0	0.0	0.0	91.8

Table 4.1. Production rate (Directorate)

The Snorre Expansion Project (SEP) is underwater development, and the largest project for increased recovery on the Norwegian shelf today. The project is estimated to contribute oil production to another 25 years at Snorre Field.(ASA, 2018a; Directorate)

Details about Snorre Expansion Project:(Project), 2019)

- An estimated improved recovery from the Snorre field by almost 200 million barrels.
- Based on 2017 value, CAPEX of slightly more than NOK 19 billion to be used.
- Initial oil production to begin by 1st quarter of 2021.
- SEP is expected to improve the recovery factor in the Snorre field from 46 %to 51%.

<u>Concept selection:</u>

- 24 new wells which comprises of 12 producers and 12 injectors
- Six new subsea templates for production and water/gas injection
- Productive life of the field is expected beyond 2040

As discussed in the background part of the thesis, not only the challenges of using MPT, but also many other details credited to the decision to use wired drill pipe for Snorre Expansion Project. Along with the many large fault blocks, the reservoir had a complex structure with both flow barriers and channels at a depth of 2,000-2,700 metres (Directorate). Although the initial investment for WDP is high, yet the focus is to drill wells that contain good length of reservoir section. For this, during drilling it is important to get more accurate downhole data using WDP. This approach might reduce the number of wells required to achieve the same production rate. However, if there arise a situation to drill more wells, time could be saved when performing LOT/ FIT, rotational check-shots and taking surveys if WDP is used.(Fosse, 2015)

4.3 Operations, problems and WPD based solutions

Field case studies have proven advantages of WDP(NOV for Total E&P) and in similar manner the Snorre Expansion Project (SEP) would benefit from the technology.

Moreover, up on discussion with the Equinor ASA drilling and completion team experts and based on the knowledge gathered from the literature study, author believes that there are more areas of WDP application. Hence, this section discusses the problems associated with conventional methods in well operations and the possible solutions with WDP to improve operational performance and reduce non-productive time.

These discussions put forward possible implementation of WDP for drilling and other well activities. However, the studies carried out below have limited scope for conclusion since these are concepts devised "on the fly" through general assessments and discussions with industry professionals. The suggested conceptual solutions will require much further evaluation to be released as a product and get implemented in well operations without compromising the safety of people and environment.

4.3.1 Drilling Operations

Studies showed that WDP provides a lot of benefits among others:

1. Obtain real time data density in the desired zone of interest without the reduction in ROP
2. Improve the hole quality by controlling the downhole tools in highly directional wells. This would result in precise wellbore placement.
3. Gain accurate reservoir exposure by receiving superior quality data in real time while geo-steering. Hence, obtain maximum production potential.
4. The high benefits of along string measurements (ASM) could be utilized within the area of well control by early identification of pack-off point and determination of influx zone(Solem, 2015). The traditional approach and influence of choke is

eliminated when the downhole pressure value could be immediately monitored with WDP compatible tools in well. This application has provided an insight to better control the downhole pressure while circulating out the kick in well control situations (D. Veeningen, 2013).

4.3.2 Tripping Operations

Fluctuations in downhole pressure is usual during tripping operations. However, in many cases this can lead to wellbore instability issues. Although mechanical and hydraulic models can forecast the borehole pressure, yet improper tripping speeds can decrease the projected pressure required for stable wellbore. Various factors contribute to the pressure differences in tripping operations such as wellbore geometry variations, drilling fluid properties, types of flow regimes, drill string eccentricities and most importantly tripping velocities (Alsubaih, Albadran, Abbood, & Alkanaani, 2018) (Gao & Miska, 2009; Mehrabian et al., 2015). The equivalent circulating density, ECD represented by the grey line illustrated in Figure 4.3 depends and vary with the type of tripping activity performed in drilling or in open hole completion phase. The area between the fracture pressure and the pore pressure / collapse pressure represents the operational window. Lost circulation relates to the interaction between the fracture pressure and the ECD. (ASA, 2006-09-21)

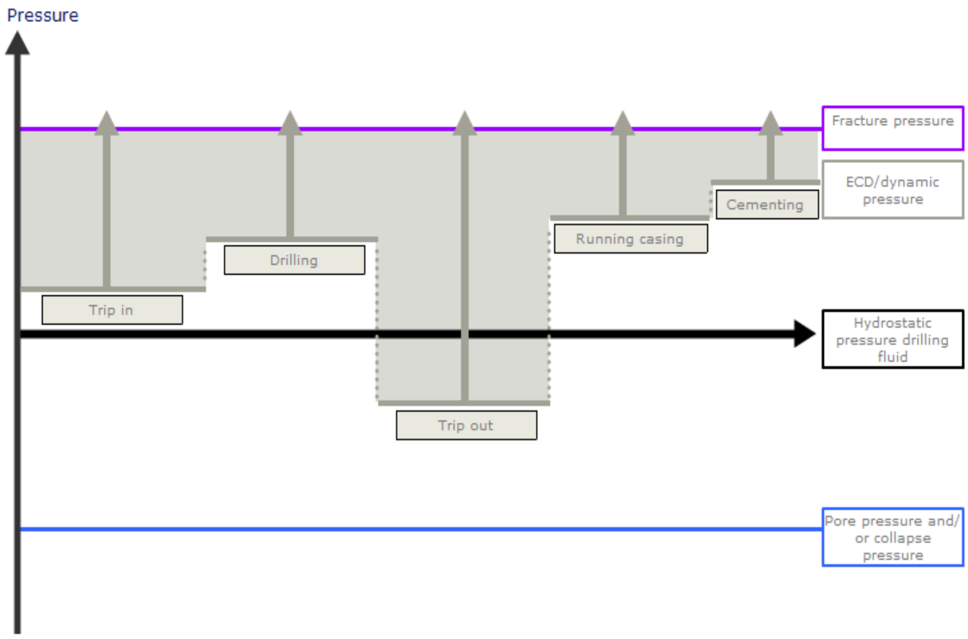

Figure 4.3. Illustration of well pressure and operational window (ASA, 2006-09-21)

As shown, it is important to precisely determine the well pressure to avoid well instability problems along with maximizing the tripping speeds. For any well activity, the objective is to carry out the operations safely by the maintaining the well stability and to reduce the non-productive time (ASA, 22.10.2004).

Problem 1:

Tripping on elevators and WDP:

The normal drill pipes used in the industry does not allow to model any real time simulation of downhole pressure (Alsubaih et al., 2018). Although WDP helps in receiving the data to surface in real time, yet this can be obtained only while the top drive system is connected. Tripping on elevators is the preferred way of operation at wellsite. Tripping could be done by connecting the top drive, but it is not preferred. This is because tripping on elevators require much lesser time than connecting the top drive to the drillstring and tripping. Hence while tripping on elevators we do not receive any real time downhole data such as pressure and temperature. Also, the initially calculated tripping velocity could vary largely, might be too high or too low based on the downhole conditions then. At present it is not possible to receive, real time bore and annular pressure by tripping on elevators. (Israel et al., 2018a, 2018b)

Solution 1:

Today, tripping is based on the only simulated swab and surge calculation which is modelled in the beginning of the operation. Example: Operations where there is a requirement for extensive reaming/ back reaming might lead to the instability of the formation. Initial simulated calculation might not help in ensuring the wellbore stability during the well activity if abnormal downhole conditions are encountered. The industry at present requires real time swab and surge modelling based on which the drilling team can lead the operations. Tripping should be carried out on wired elevators or developing an equipment that could read/ provide the data from WDP to the surface network via the connected elevators could be a solution. Hence the requirement to torque-up the top drive to the WDP could be eliminated(Israel et al., 2018b). Real time modification of the tripping data would help in adjusting the drilling fluid parameters as per the requirement. Models that could be simulated based on the real time data received while tripping with WDP will help to predict the future responses to optimize the tripping speed(Israel et al., 2018b). This might contribute to improvements in well operation practice and subsequently the wellbore integrity. For more clarification, please see section 4.3.7, Figure 4.15 as well.

Problem 2:

Wellbore uncertainties:

Presence of ledges and shoulders in the borehole have led the BHA to get easily hung up during tripping operations. This also applies for smaller and more flexible components like TLC (Tough Logging Condition Systems) and wireline equipment. Consequently, tripping of the BHA, running of casing and liner, also installation of sand screens and zonal isolation packers might become more difficult due to ledges and shoulders. Hence there has been a potential of severe damage to downhole equipment. (ASA, 22.10.2004, 2006-09-21)

Solution 2:

EMS (enhanced measurement system) tools along with wired drillpipe network and wired BHA components deliver downhole drilling dynamic data in real time. It ensures that highly accurate torque and weight measurements experienced by the downhole BHA are received at surface in real time, thus providing a better control of downhole operation ((EMS), March 8, 2017). Hence mitigative actions could be schemed out immediately.

Problem 3:

XLOT, FIT and LOT operations:

As per the detailed operational procedure (DOP) for XLOT operations, receiving the ESD value is important before XLOT at the casing shoe. We receive the ESD value from the MWD tool which might not be accurate in case the drill string was reciprocated. As a part of risk analysis, the ESD could be checked against the hydrostatic pressure (Procedure, 2019). The figure 4.4 shows the different pressure stages during a XLOT operation that use drill pipes. (presentation)

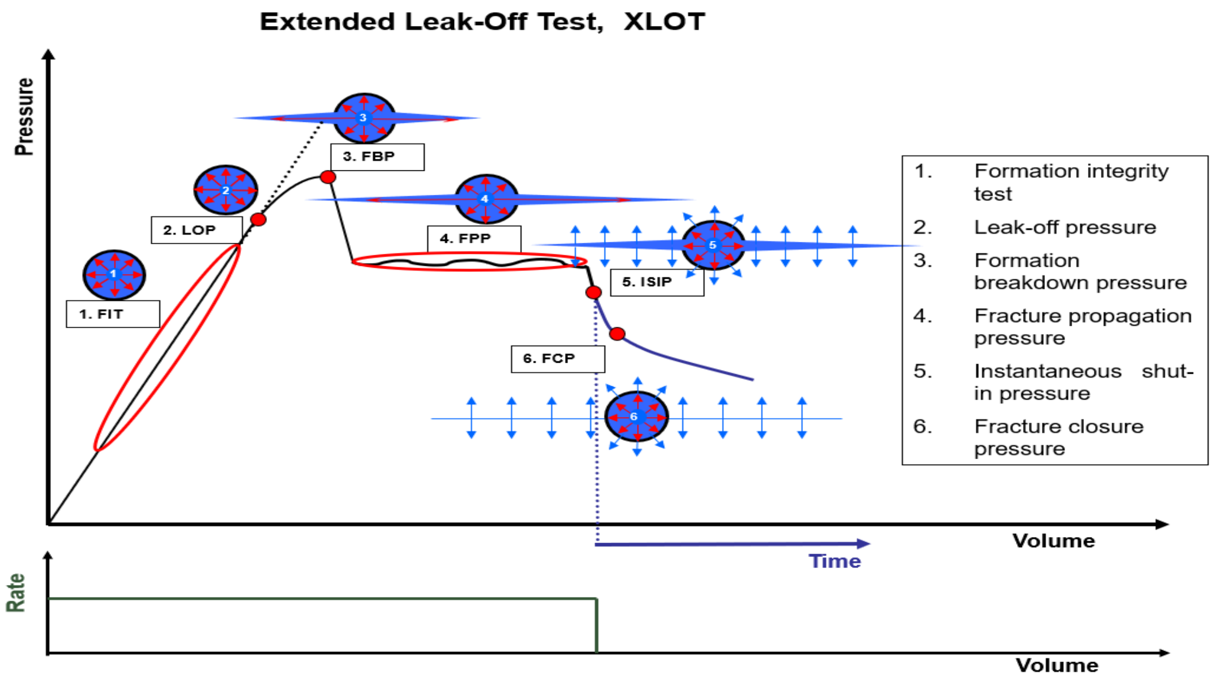

Figure 4.4. Extended Leak-Off test, XLOT(ASA)

During the LOT or FIT operations, the recorded data is received from sensors that are powered by battery. Based on the ability of the tool, data can be recorded within equal intervals of time. And only after the test has been completed, the data is transmitted to surface. It is important to note that most of the cases the highest and the lowest pressure data will be sent to the surface in real time.

However, the complete pressure profile can be obtained from the internal memory of the tool after it is retrieved from the hole. Only after this, the formation strength below the casing shoe can be accessed.

Solution 3:

The application of WDP will eliminate the function of the downhole memory gauges. Hence the formation strength can be studied real time and analyzed during the operation. This might decrease the time required for the overall process. Unlike the normal XLOT operation with drill pipes, WDP provides a clear view of the downhole condition while performing this operation. All the stages shown in figure 4.5 could be monitored real time with WDP network.

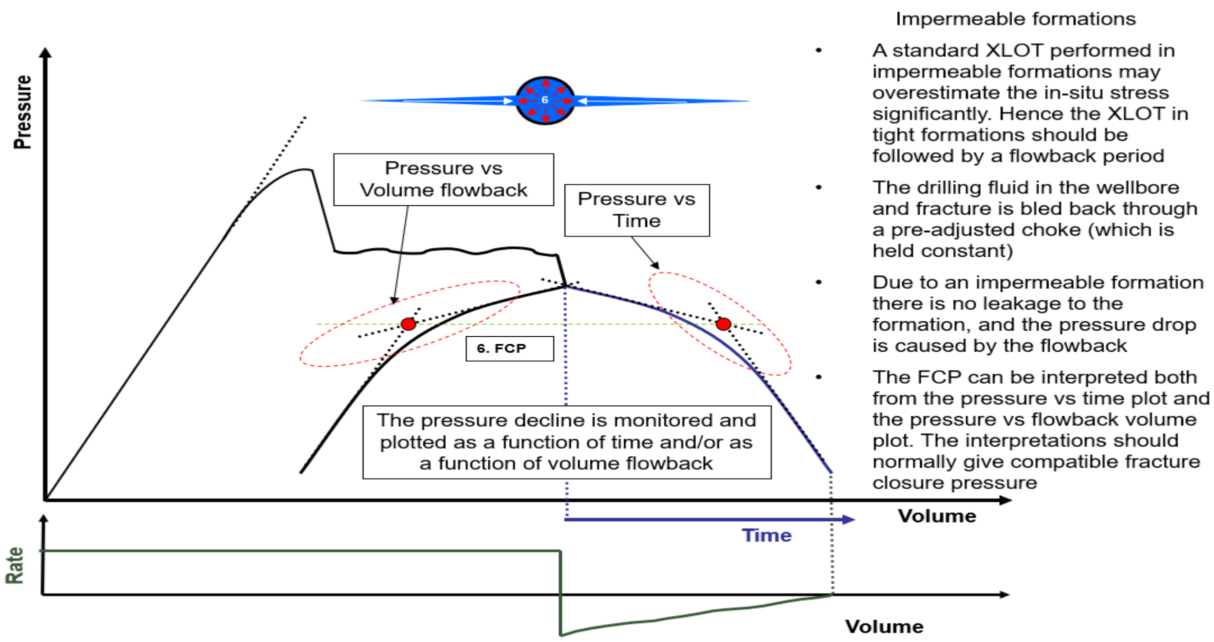

Figure 4.5. Pressure decline curve- XLOT Operations (ASA)

Problem 4:

<u>Elimination of memory gauge tools:</u>

Receiving pressure points while drilling is the usual procedure to calculate the surge and swab pressure in open hole for the later operations. The problem here is, it is not always possible to get the pressure points at the required depths since the commands to the tools are send via MPT. This consumes time and sometimes achieves success after repeated try. This increase the NPT. Also, the pressure data received is not real time but is stored in the memory data which is unloaded once the tool is at the surface. (Trestakk, 2019)

Solution 4:

Using WDP, instant commands could be sent to the tools unlike MPT system. Hence decrease in NPT.

Problem 5:

Injection wells:

Tripping or drilling activities in area where injection wells are active, one must carefully drill through since the original drilling window will be changed. The main reasons are because of the injection activities in the region, the pressures within the region will alter largely after certain period. Understanding the pressure regime during any operation in injection well is significant. Along with pressure, temperature plays a vital role (ASA, 22.10.2004, 2006-09-21). There could be drastic decrease in temperature which in turn decrease the fracture pressure in injection wells, (illustrated below in figure 4.6) thereby drilling into the flushed zone is an issue for oil companies (Internal document). It has been informed from Equinor ASA that there are 12 injection and 12 production wells for the Snorre expansion project (SEP) (Project), 2019).

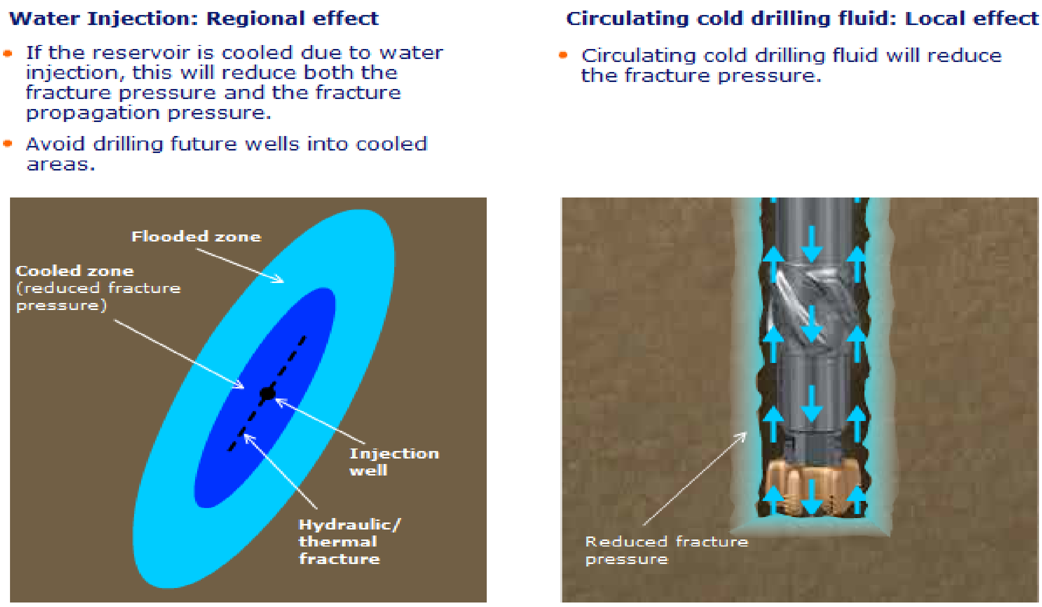

Figure 4.6. Effect of water injection(ASA)

Solution 5:

A better understanding of the downhole conditions is imperative while drilling or completion activities are performed within the injection zones. This is because the formation stress could have been altered severely after prolonged and continuous IOR (Improved Oil Recovery) activity such as water or polymer injection in these areas (Reservoirs, 2019). WDP could significantly benefit in receiving constant and concise real time data of both bottom hole temperature and formation stress/pressure gradients. Hence application of WDP network with compatible BHA tools could foresee the cooled areas.

4.3.3 Cementing Operations:

Scenario 1: Assistance to cementing specialist

One of the most critical operation in well activities is cementing. For the well integrity to be met, it is important to ensure that proper placement of cement along the annulus is achieved. Discussed scenario with Equinor ASA: While cementing a liner or production casing, placement of ASM along with the liner hanger running tool (LHRT) will provide an accurate heat map showing the density of the different fluids pumped down the wired pipe such as spacer fluid, lead cement, tail cement and drilling mud in real time. This will provide the required data for the cementing specialist to understand the lift pressure above the liner and further use it to calibrate the hydraulic models(Israel et al., 2018a, 2018b)

Scenario 2: Annular pressure while cementing

One of the crucial issues during liner cementing is the interzone/annular gas migration which effects the well integrity. The gas migration happens when the hydrostatic pressure is lesser than the formation pressure at that gas invading zone (Zhou & Wojtanowicz, 2000). To understand the fluid migration during liner cementing, placing pressure and temperature sensors/ ASMs as close to the running tool of liner hanger could provide a better understanding of the state of cementing operations (Cooke, Kluck, & Medrano, 1983). If there could be an availability of pressure data/ ECD while cementing the liner, the integrity of the cementing could be judged. Failure to seal the annulus behind the liner might lead to the annular gas flow and might appear at the surface of the well. This could eventually lead to leak at liner top due to sustained pressure, fluid flow between the different zones outside the liner and eventually loss of well integrity. Because of flow between the zones, there will be loss of hydrocarbons and problems related to stimulation operations later in the well.

Eventually this leads to expensive cementing operations such as squeeze cementing which requires additional equipment, thereby increasing the NPT.

Two major causes of cement failure are

a) Improper displacement of drilling fluid before pumping the cement slurry.
b) Pressure loss in the cement prior to attaining the strength (Israel et al., 2018a).

Solution to both cases discussed above:

As shown in the figure 4.7, are the suggestions from British Petroleum after the trials in Alaska field. A modified engineering design with wired auxiliaries is the prerequisite. Developing a wired cement head or configuring the data swivel to be placed below the cementing head will enable in transferring the real time data to the surface via WDP.

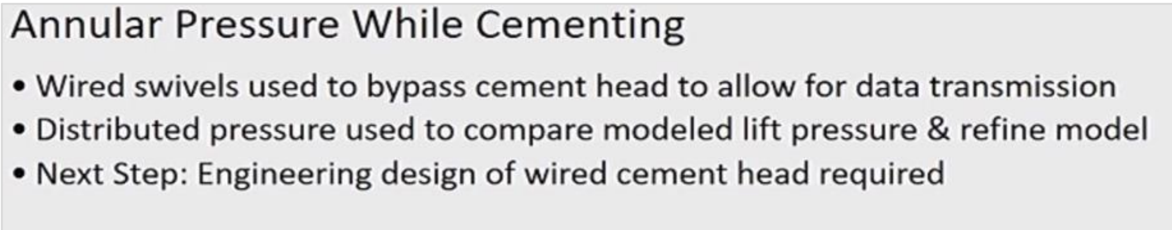

Figure 4.7. Summary from BP project (Israel et al., 2018b)

Problem 2:

Ensuring the cement displacement

For better placement of cement in the wellbore annulus, it is important for liner string rotation while cementing. However, for highly deviated wells, there is a large difference between the RPM and torque at surface when compared to the downhole RPM and torque at the tool. Any load or rotational increase might lead to pre-mature liner hanger packer setting. (Pager, 2019)

Solution 2:

Using EMS, there is a possibility to measure the torque, weight and rotation at defined depth of the liner hanger running tool((EMS), March 8, 2017), Refer figure 4.13.

4.3.4 Wellbore cleanout (WBCO)

A clean hole is defined as a wellbore when trouble-free operations can be performed during drilling, tripping, logging, running and installing casing, liner or screen. The best hole cleaning practices depend upon factors such as surface equipment, hole size, operational phase, hole inclination, fluid properties, flow rate, rotation speed, drill string components, formation characteristics, drilling rate, time spent circulating at section TD. Some formation characteristics like faults, loss zones and depleted reservoirs may require special procedures. Sufficient hole cleaning depends on the operations to be performed. (ASA, 2006-09-21)

For example:

- Tripping operations requires a cleaner hole than drilling
- Running and cementing requires a cleaner hole than tripping.
- Running screens or completion equipment requires a clean hole as the possibility for rotation, down weight and circulation is limited.

Continuous monitoring of relevant parameters is required to ensure adequate hole cleaning. Hole cleaning monitoring is performed by monitoring the indicators such as torque and drag, cutting returns, surface drilling parameters, drilling fluid parameters and downhole drilling parameters.(ASA, 22.10.2004, 2006-09-21)

4.3.5 Wellbore cleanout in drilling phase

The smaller hole sections are often drilled at highest inclination. Improved hole cleaning is required at high inclination since inefficient hole cleaning increases the risk of lost circulation. Accumulated cuttings in the wellbore increase ECD. Also pack off situation is likely to occur while tripping and connections time.

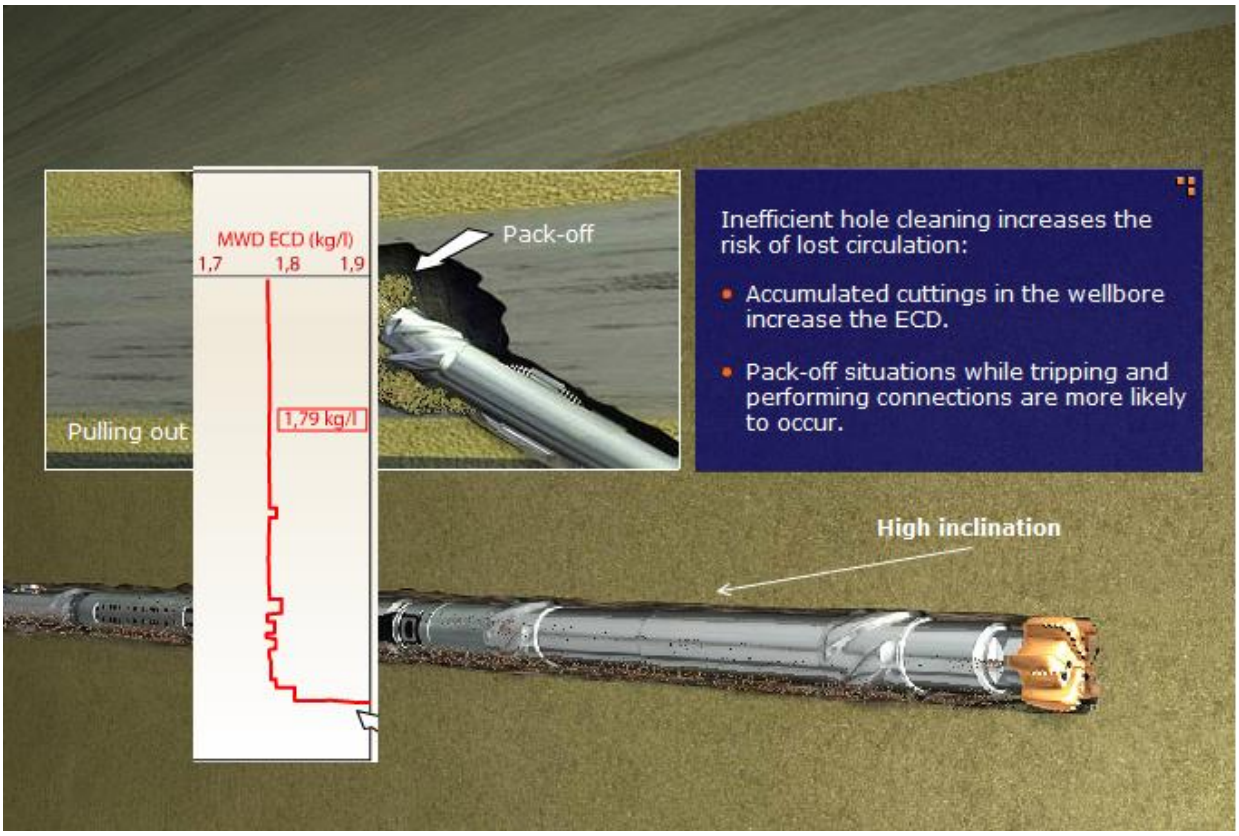

Figure 4.8. Effect of pack off on ECD (ASA)

Poor hole cleaning is usually detected by following the trend data.

1. **Drilling parameters**: Cuttings accumulated in the annulus affect the toque and drilling fluid pressure in the following ways:

- Fluctuating and increasing torque.
- ECD and ESD variations(Bekkeheien).

Note: The fluctuation in downhole torque can be recognized immediately by EMS present within the wired BHA. EMS could provide the real-time value of bit torque ((EMS), March 8, 2017). This might give an immediate indication of formation change or alert while drilling. Similarly, ASM could give instant indication of pressure build at defined depths(Measurement, March 8, 2017.)

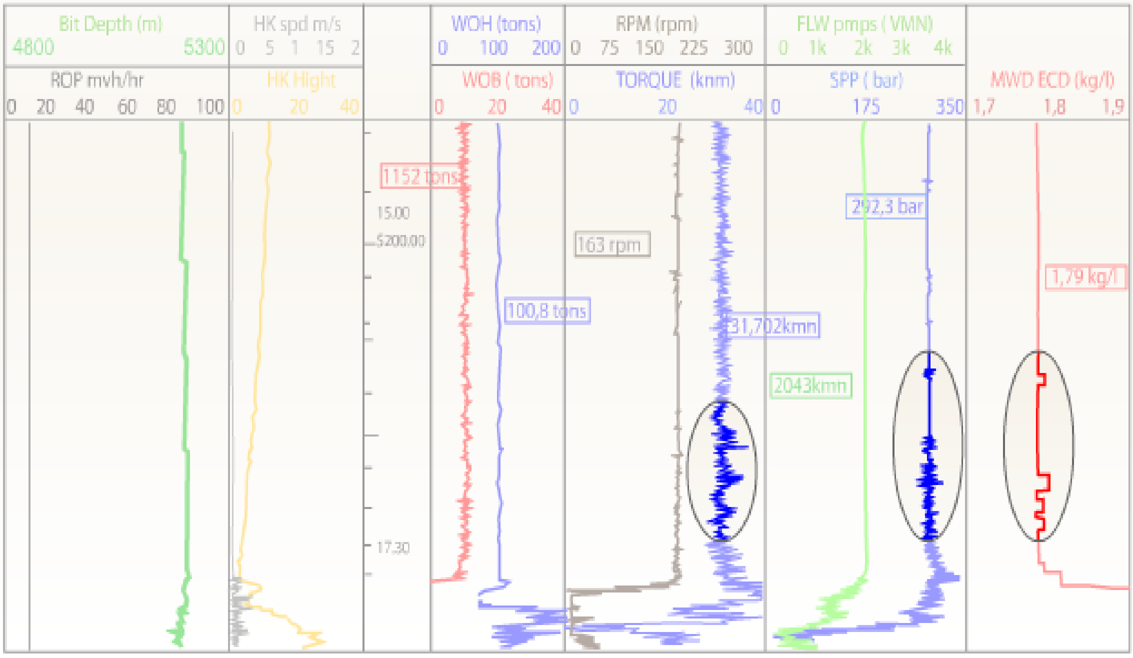

Figure 4.9. Parameters monitored for effective hole cleaning(ASA)

2. **Drilling fluid properties**: Insufficient removal of solids/cuttings can be observed when there is an increase in viscocity, fluid density in/ out, sand content and presence of low gravity solids.(ASA)

Note: Any change in the fluid density, solids or cuttings in the fluid could easily be identified by the ASMs, but no technology has been developed to integrate WDP with tools that could measure the viscosity/ downhole mud rheology. Further research must be carried out in this area. Developing mud sensors that could analyze real time downhole mud properties at different depths, then fingerprinting of gas with mud in use will help in detecting the presence of reservoir fluids in annulus.

3. **Cuttings Return:** One of the significant function of drilling mud is to transport the cuttings bed to the surface. Sometimes, observing the cuttings in the shale shakers and understanding the hole clean or wellbore situation might be late/ ineffective. The

typical warning signs are insufficient or no cutting returns for a particular rate of penetration along with the variation in cutting returns (ASA, 22.10.2004, 2006-09-21).

Note: It might be late when warning signs such as cuttings return indicate the downhole well conditions. WDP bring into future an automated well control management along with AOS (Automated Operating System) where the well could be controlled by taking the insight provided by the data (downhole pressure) from ASM and thereby mitigating any risks in the event of well control (Israel et al., 2018a). This could be the same with estimation of cuttings bed in the annulus.

As a safe practice in the industry, the following parameters as shown in the figure 4.10 are to be adjusted to get the optimum hole cleaning.

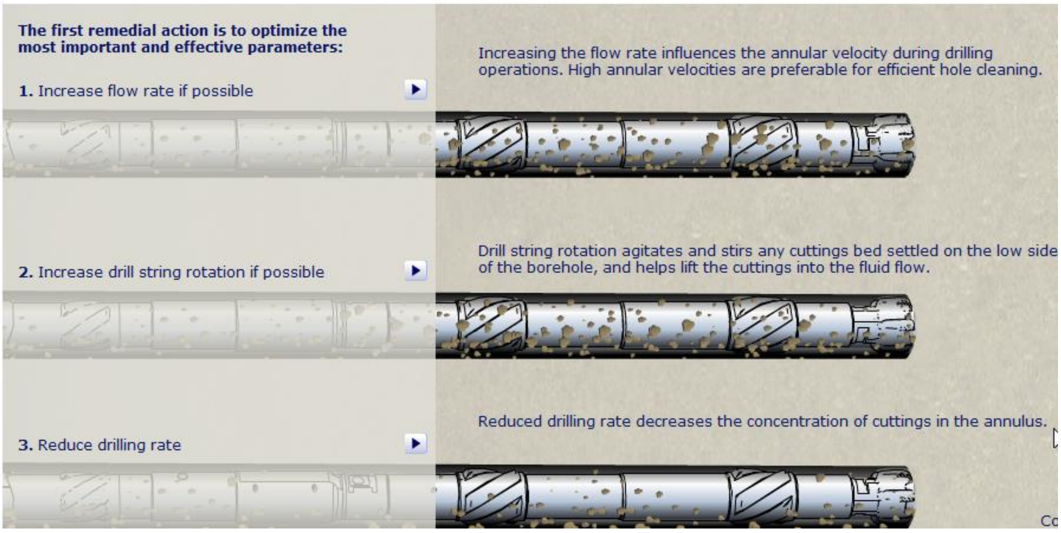

Figure 4.10. Parameters required for optimum hole cleaning(ASA)

a) **Flow rate** – The hole cleaning effect at higher flow rates will not necessarily be improved. There is also an increased risk of equipment failure due to excessive wear/erosion at higher rates. This it is important to ensure these parameters does not conflict with limitations for top side or downhole equipment and that the flow rate does not cause the ECD to exceed the fracture gradient. (ASA, 22.10.2004, 2006-09-21)

WDP and ASM: Effect of ECD

Cuttings bed could accumulate in the wellbore that might lead to increased wellbore problems such as pack-offs or stuck pipe during lower completion run in. While drilling, if cuttings accumulate in the annulus, EMW increases which indicates the hole clean must be improved. WDP along with pressure sensors gives real time EMW. This would signal if the flow rate should be increased for better hole cleaning.

b) **Drilling string rotation:** As a standard practice, drilling industry use continuous and steady rotation at the maximum available RPM. It is crucial to ensure that the rotation speed does not result in excessive surface torque or downhole vibrations.

WDP and EMS: Effect of torque and load

Any increase in the downhole torque and vibrations could be identified by the EMS present in the downhole tool. Hence any possibility of drill string twist could be easily avoided in highly deviated wells where rotation of the string is mandatory during the operation.

c) **Drilling rate:** A reduction in drilling rate might be required to achieve efficient hole cleaning. A steady drilling rate is recommended to enable early detection of downhole problems with changing trends in the parameters. This also helps in avoiding slugs of cuttings in the annulus. The figure 4.11 explains the standard drilling rate recommended for good hole cleaning in industry.

WDP and effect of ROP

WDP enabling the new technology of seismic-while-drilling which could forecast the formation ahead of the bit. This will provide an understanding of the optimum ROP that could be applied. Increased ROP without proper real time formation evaluation might result in tool failure or stuck pipe scenarios. Hence, controlled optimum ROP with WDP network could decrease the unexpected tripping operations and save time. (Grymalyuk et al., 2016)

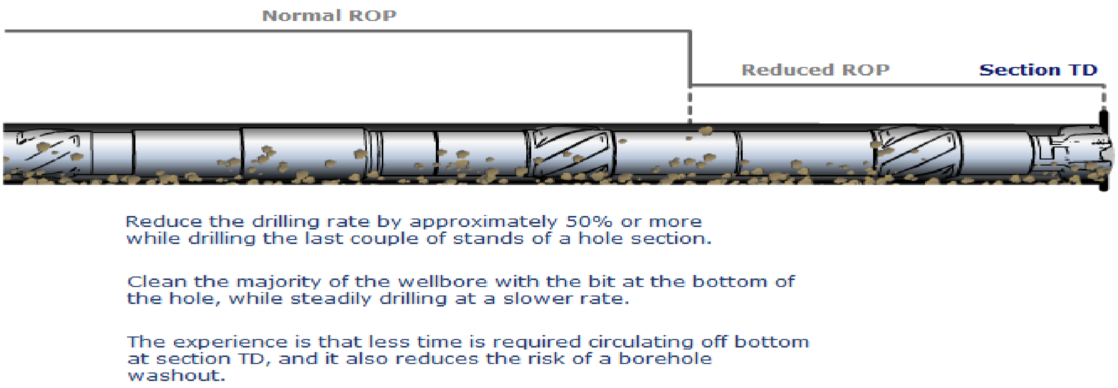

Figure 4.11. Drilling rate practice in a section (ASA)

Problem 1:

<u>NPT during WBCO:</u>

In general, wellbore cleaning typically requires a higher time since it is difficult to estimate when the well is completely clean. Due to this, there is a practice of off-bottom circulation for a longer period without completely understanding the bottom hole condition. (ASA, 2006-09-21)The standard practice of CBU is shown below in figure 4.12.

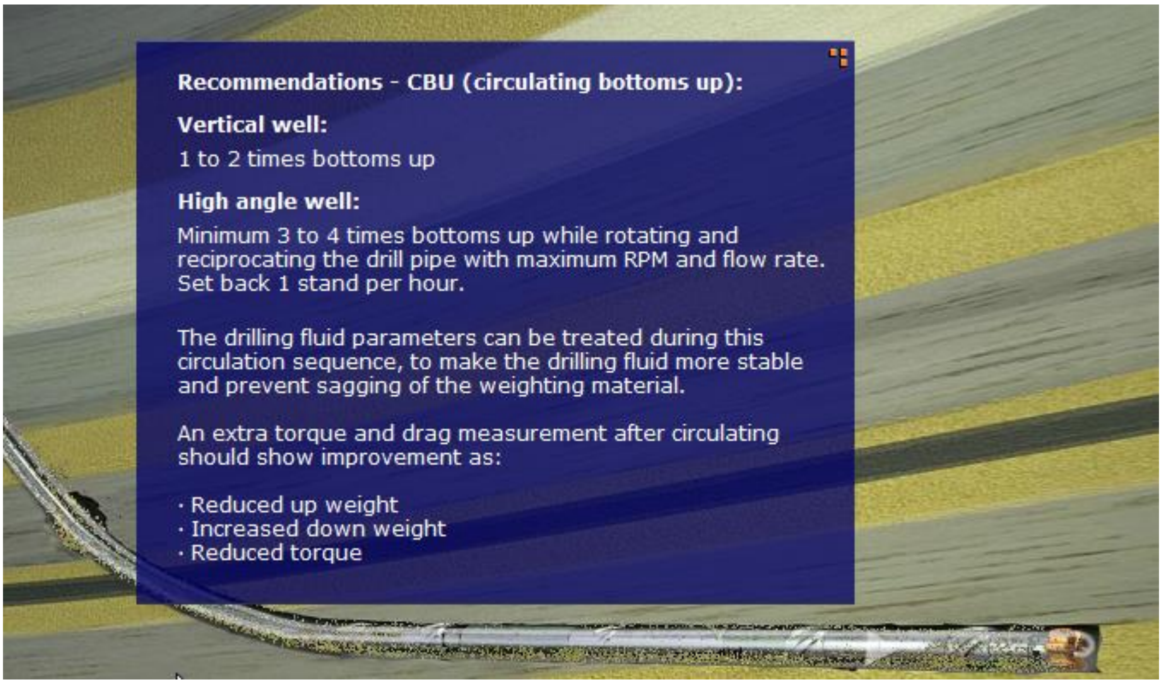

Figure 4.12. General CBU recommendations (ASA)

Solution 1:

WDP can optimize CBU

The requirement for minimum 3 to 4 times bottoms up is due to the large difference in the way cuttings are carried out of a vertical hole compared to a high angle hole. Cuttings from high angle holes might not appear as continuous flow at the shaker screen but can arrive in batches. Note: Placement of ASM throughout the drillstring at defined lengths will provide the annular pressure at those depths. This helps in understanding the pressure profile regimes along the wellbore annulus i.e. ECD. Based on this ECD estimation, CBU can be determined and hence wellbore cleanout time can be evaluated more precisely.

4.3.6 Wellbore cleanout in completion phase

Advantages of reaching a proper wellbore cleanout before running completions are as follows

- Least damage to the reservoir.
- Safe installation of completions (gravel pack jobs, screen installation etc.).
- Least possibility for screens to get plugged.
- Reduction in NPT.

4.3.6.1. 7” liner job

Mechanical downhole tools are used in cleaning of the casing for better placement of the wellbore fluids. Tools such as scrappers and filters are used to remove scale or mud along the casing wall. Also, the presence of the debris after drilling out shoe track or the residual cement after the cementing operations in a liner job affect the wellbore in later well completion stages (EMS; Pager, 2019).

Problem 1:

<u>Mud weight control:</u>

During the well bore clean operation of 7” liner, it is usually hard to ensure if the well is clean. This is caused by the uneven fluid properties in the well due to displacement with various fluids of different mud weights. Also, in high-angle well, weighting mud and LCM can settle in the flowing fluid due to gravitational forces. If settling happens for longer time, then the upper section of the wellbore will lose mud weight. This eventually results in reduction of hydrostatic pressure in the hole and the formation fluid might enter the well (Control).

Solution 1:

As discussed earlier, placement of ASMs throughout the string at pre-determined lengths provide an indication of pressure in the annulus and inside string. Hence in high angle wells, the decrease in mud weight due to settling could be easily identified at early stage with WDP network (Measurement, March 8, 2017.).

Problem 2:

<u>Real-time monitoring of drilling or completion fluids:</u>

Ineffective displacement of wellbore fluids could cause well stability issues in open hole completions, improper gravel packing through different mechanics, reduction in well productivity and ultimately increasing the NPT (Fleming, 2018; GravelpackDOP).

Solution 2:

WDP provides solution to both the above listed problems. Well clean can be confirmed when the real time fluid density (ECD) in the wellbore annulus is established by the ASM along with WDP. However, completion well clean out jobs usually consist of the scrapers (for double scraping the packer setting depth), magnets, filters which are presently not wired. Hence the need to wire these tools for making their application robust. (Fosse, 2015; Measurement, March 8, 2017.; Solem, 2015)

4.3.6.2 5 1/2" liner job

Problem 1:

Drillstring Failure

During the WBCO jobs there is a risk of twisting the drill pipe if the operation is carried out with rotation. (Chen, Shen, Yun, Dong, & Chen, 2018)

Solution 1:

EMS (enhanced measurement system) tools along with wired drillpipe network delivers downhole drilling dynamic data in real time. It ensures highly accurate torque and weight measurements are received at surface, thus providing a better control of downhole operation ((EMS), March 8, 2017).

Problem 2:

Liner rotation while cementing:

For better placement of cement in the wellbore annulus, it is important to provide a minimum rotation to the liner string while cementing. However, there is a large difference between the surface RPM and torque applied and the downhole RPM and torque received/ experienced at the tool (Cooke et al., 1983; EMS; Pager, 2019).

Solution 2:

Using EMS, there is a possibility to measure the torque, weight and rotation at defined depth ((EMS), March 8, 2017). This will enable the engineers to provide the required RPM at the surface by understanding how much torque is optimum for the downhole BHA. The weight given at surface will not be completely transferred to the downhole tools in case of extended reach wells due to high deviation. This EMS technology will greatly benefit well service tools that require rotation and weight to set and release. As shown in the figure torque gets trapped in string and there could be large deviation between surface torque and downhole torque. The downhole torque readings can be used to ensure that the liner or any mechanically set downhole tools was set without damaging the equipment.

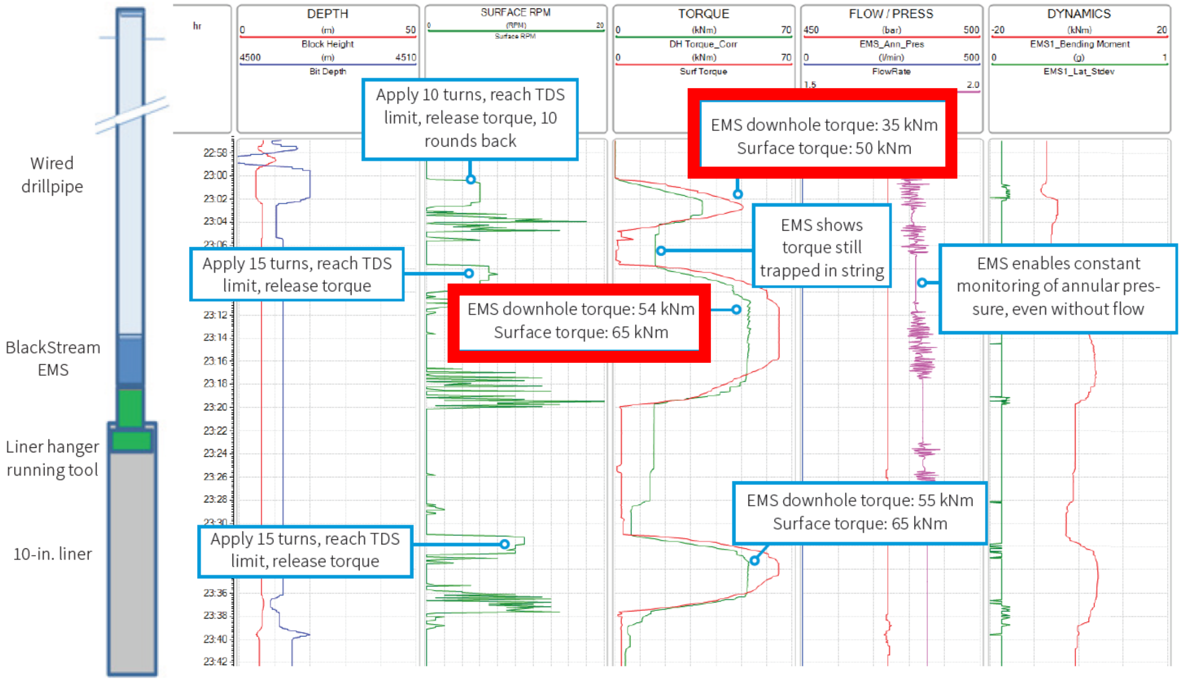

Figure 4.13. The time-based log shows measurements received by the EMS tool placed just above liner hanger running tool (EMS)

4.3.7 Perforation

Wellbore problems such as loss circulation, kick/inflow or fracturing are caused due to swab and surge while tripping operations (Gjerstad, Sui, Bjorkevoll, & Time, 2013). An increase in the surge and swab pressure is experienced when the tripping velocities are high. However, a low tripping speed results in increase of NPT especially in drill ships, floaters and semi-subs. Swab pressure can be described as the decrease in the bottom hole pressure while tripping downhole tools out of hole. In general, as the downhole tools are tripped out of the hole, there is a reduction in the annular velocity, eventually loss in friction pressure (Alsubaih et al., 2018). Reduction in the occurrence of inflow or lost circulation is possible by minimizing the swab and surge pressure. This is feasible if accurate trip velocities could be calculated in real time (Gjerstad et al., 2013; Zhang, Deng, Li, Hou, & Wang, 2018).

Problem 1:

<u>NPT in perforation jobs:</u>

After perforation of a well at the required intervals, the trip out velocity is based on the simulated data and not on the real time data. This can lead to NPT scenario when the trip out speed is very less (Israel et al., 2018b). And if the trip out speed is very high, the swab pressure increases and a possibility of inflow leading to a kick/ well control situation might arise (Israel et al., 2018a).

Solution 1:

This case study is from Visund Nord IOR D2 well, which had cased the reservoir sections with liner and had to be perforated (Visund Nord IOR D2 Well, 2018). Using Halliburton, landmark software wellplan, the POOH speed after perforation of guns were simulated and Figure 4.15 shows the swab/surge simulated results. In this simulation, regardless of the wellbore being live or not, the perforation fluid is assumed to generate an over pressure. Since there is not means of knowing whether the guns have been fired or not, operators tripped out the perforation BHA using the simulated POOH speed in order not to receive influx. This resulted in NPT.

Due to tool failure not all the guns in the BHA were fired. This could only be understood once the guns were tripped out and lay down on the rig floor. In general, a higher trip out speed could have been used since all the guns were not fired.

To solve tripping speed issue, using wired drill pipe along with wired BHA (wired guns, wired firing head etc.) for perforation would provide the real time swab pressure after the guns are detonated. If there is the availability of the real time bottom hole pressure, one can optimize tripping speed until the bottom hole pressure a little bit higher than the reservoir pressure as illustrated in the Figure 4.14.

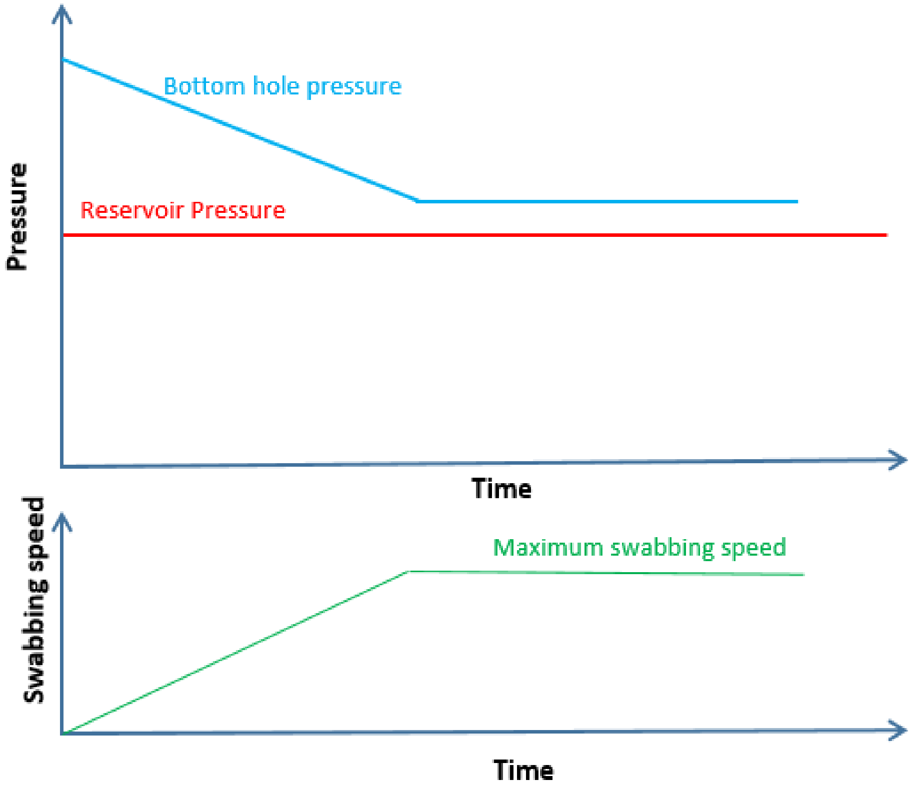

Figure 4.14. Illustration of real time speed maximization respect to bottom hole and reservoir pressure

A system that could trip using actual data downhole and not the simulated one, is the requirement for the industry. Also, further studies need to be carried out with WDP system to understand in real time if the guns have detonated when in hole.

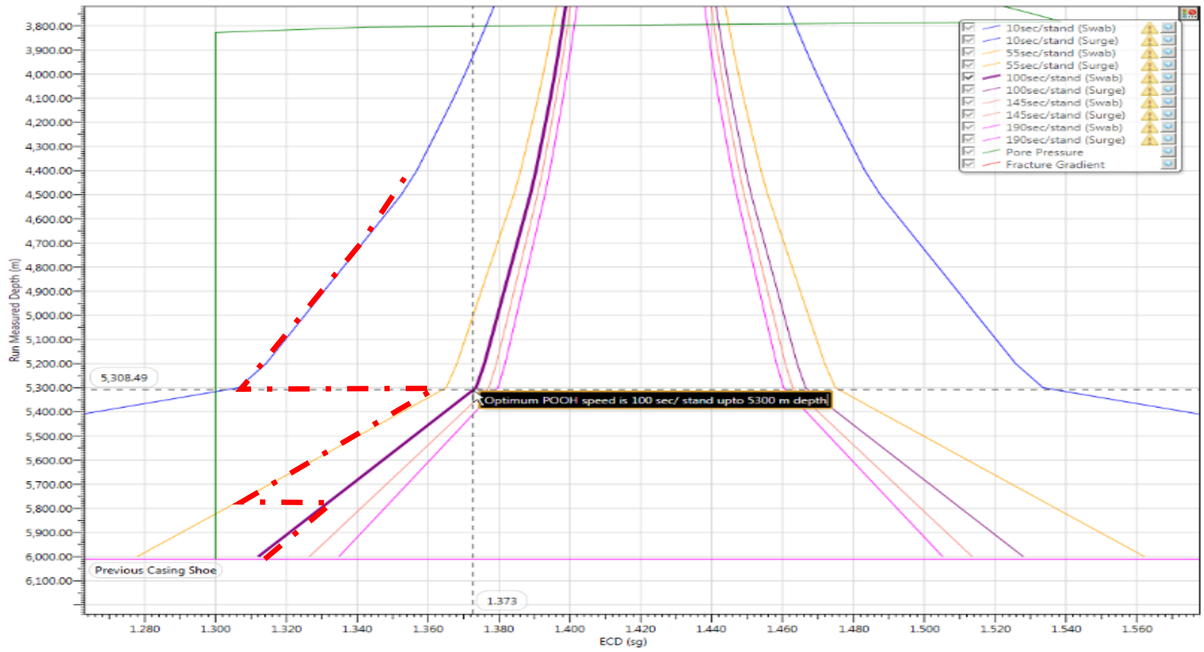

Figure 4.15. Simulated Swab and Surge in Visund Nord IOR D2 well (Visund Nord IOR D2 Well, 2018)

If there was an availability of the real time data through WDP which is same as the memory data we received after the operation, tripping out speed could have been faster. For instance, according to Figure 4.15, the simulation result showed that the safe tripping speed out at 100 sec / stand from 6010 m (TD) to 5300 m. However, if we had a real-time downhole pressure data, one can optimize the speed as illustrated in the red broken line, which shows that one can tripped out with the section 6010-5800m with 100 sec/ stand and section 5800-5300 with 55 sec/ stand. After 5300m, the speed can be increased to 10 sec/ stand. This illustrate how we can increase tripping speed and hence reduced non-productive time.

Problem 2:

Gel strength and operational impact:

When perforation pills/drilling mud stays in static condition for a long duration in the well, rheology of the fluid in the well increase. Hence it is important to break the gel before starting the operations. High frictional factor occurs when thick fluid in the well consumes a lot of energy. This results in high ECD which might exceed the geo-pressure limits. If the formation cannot withstand the surge pressure, lost circulation occurs which in turn might cause well ballooning and well control situations. The same is the case with perforation pills which is displaced in the annulus before firing the guns. The fluid properties in the well might vary after firing the gun (perforation). The guns are tripped out using the simulated data rather than the real time data (Control; Sagging_DrillingMud).

Solution 2:

The potential of WDP to get the actual ECD rather than the simulated when displacing out the perforation pill could be utilized. However, as we discussed in tripping operations (4.3.1), there will be requirement for wired elevators or some other means to transfer real time data.

4.3.8 Completions

The possibility to place pressure sensors in the drill string and simultaneously receive the real time data, will improve the potential to observe fluid communication in the wellbore annulus while acidizing, squeeze cementing, perforation and to further utilize the benefits of the ASMs with WDP while RIH completion equipment (drill pipe set packers, lower completions, downhole sand control tools etc.). It is important to note that the discussion on completion is not related to upper completion where high grade tubings are used and not drill pipes.

Problem 1:

Mechanical set completion accessories:

During installation of mechanically set packers or liner hanger (packers) on drill pipe, there is a chance of not achieving the desired downhole weight at the packer depth, which is the part of the setting procedure/ DOP. Also, some specialized packers and downhole plugs such as RTTS® packer, EZ Drill® plugs and VAULT® Plug (EZSVPlug; RTTSPacker; VaultPlug) requires a fixed number of rotations of the drillpipe at surface to set bottomhole. In highly deviated wells/ ERD wells, these rotations could alter due well geometry up to the setting depth. This could result in packer/ tool failure since we only have the surface weights.

Solution 1:

Exploiting the function of EMS could be a productive way to receive the downhole weight experienced at the tool. E.g. Placement of EMS in the running tool of the packer/ liner hanger could provide the real time value of weight at that depth ((EMS), March 8, 2017; EMS)

Problem 2:

<u>Lower completion issues:</u>

In open hole sand control completion, most of the failures/ NPT can be traced to inappropriate hole cleaning. As a result, many completion related issues are experienced such as inability to run sand screens to the target depth, inability to operate fluid loss control valve, incomplete gravel packing, screen plugging, inability to set gravel packers etc. (Fleming, 2018)

Solution 2:

As discussed in WBCO problems 4.3.4, 4.3.5,4.3.6 sections well clean can be confirmed with the usage of ASM with WDP. Also, in gravel pack operation there are different density fluids that are pumped into the well. Proper monitoring of the flow across the drillstring provides a precise understanding of downhole mechanism(Measurement, March 8, 2017.).

Problem 3:

<u>Mechanical set downhole tool challenges:</u>

Installation of gravel pack/ open hole completions are often faced with the risk of stuck pipe. To further add, the packers used in these operations are set on compression (E.g. 10-ton compression at packer) or tension as per the detailed operational procedure. There could be a possibility of packer setting failure or stuck pipe in these completion operations (GravelpackDOP).

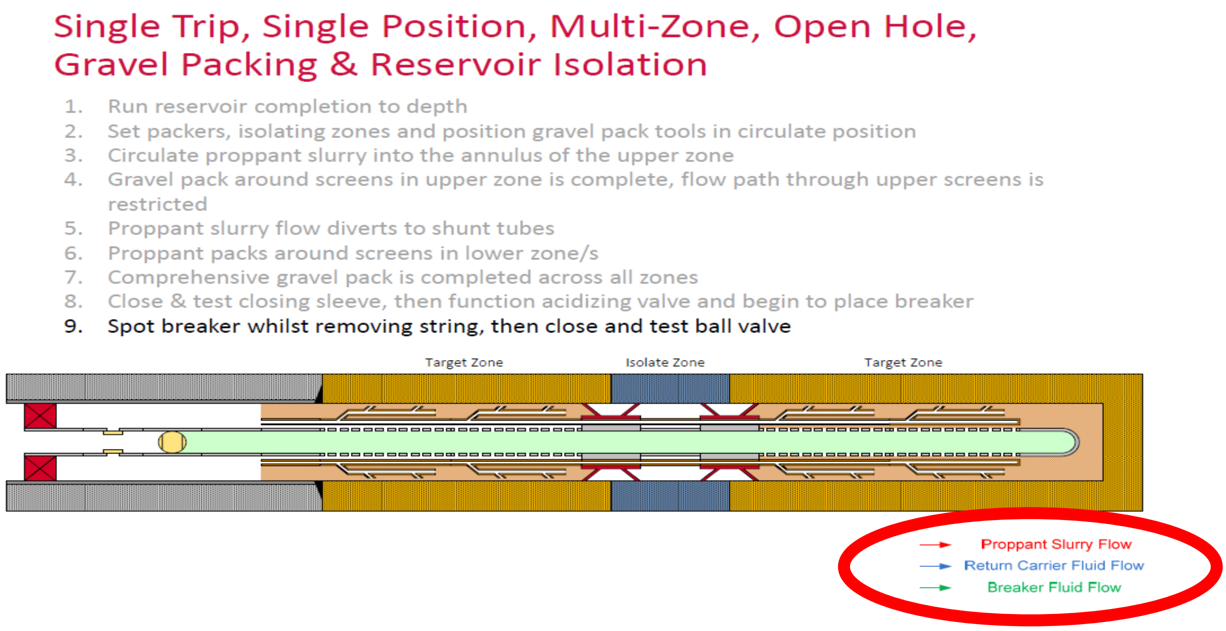

Figure 4.16. RIH gavel pack (GravelpackPDF)

Solution 3:

Using EMS, there is a possibility to measure the torque, weight and rotation at defined depth ((EMS), March 8, 2017).This will assist in proper setting of packers. As marked in the figure 4.16 above, (GravelpackPDF) three different slurry are displaced / pumped in the wellbore during gravel packing jobs (GravelpackDOP). ASM might benefit to understand if the slurry has been fully placed within the wellbore annulus or as the operational requirement suggests. Using ASM as close to the tool that is needed to be POOH after the operation will provide a precise understanding of the fluids being displaced along the wellbore in real time.

Here it is important to understand the concept of seep fingerprinting that could be used to access the effect of distinct sweep regimes. As shown in the figure 4.17 below, the dark section represents the higher annulus pressures. The ASMs can produce this “heat-map” that can be used to study the cutting load/ slurries transported up the sweep (Israel et al., 2018a, 2018b).

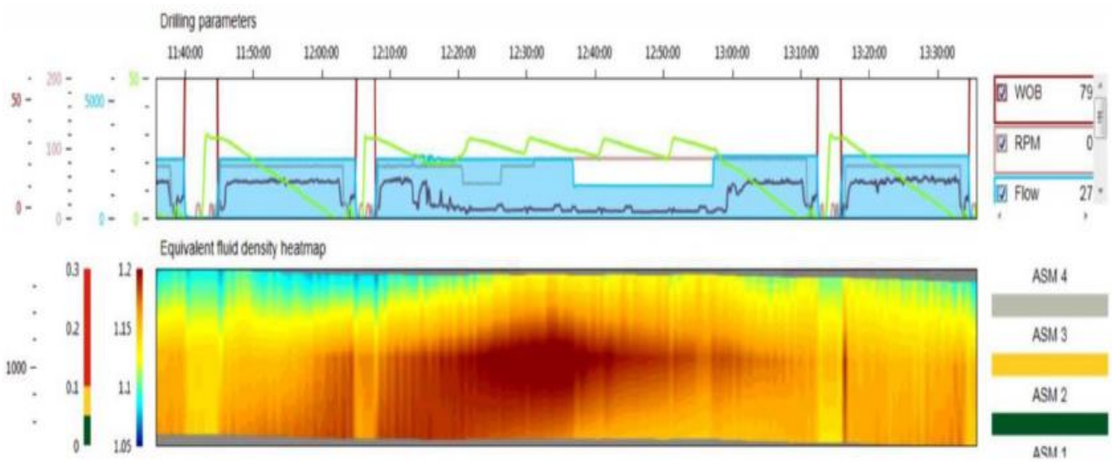

Figure 4.17. Sweep visualization with distributed sensors(Israel et al., 2018a)

Problem 4:

<u>Lost circulation issues:</u>

Liner running in highly deviated open holes (greater than 90) requires rotation. However, sometimes there is a sudden drop in annular pressure and surface stand pipe pressure, often in combination with increase in torque. This is a result of lost circulation. While tripping including the connection times, most of the lost circulation arise during pack-offs. Also, identification of the precise lost circulation section can be very difficult(Mehrabian et al., 2015).

Solution 4:

Availability of real time logs and geological information provided by WDP during drilling will help us understand possible weak zones (NOV for Total E&P). During liner operation it is not yet possible to receive real time downhole data below the running tool (packer or liner hanger running tools)(EMS). More discussions are required to further investigate the operations. ASM placements in the drillstring provides an estimation where there could be a possibility of pack offs, stuck pipes etc. Hence lost circulation areas can be identified even during open hole completions and mitigative actions can be devised by pumping LCM or other proper risk assessments(Measurement, March 8, 2017.).

4.3.9 Side tracking

Problem 1:

Limited data availability of old wells:

In old wells where the casing tallies might be missing or inaccurate, there is a need to run wireline logging tool to estimate the depth of casing collar before side tracking jobs. This is necessary for the efficient placement of whip stocks, optimizing casing exit operations. The operation for casing exit is critical since it is the only option to enter the side track for further operations in future. As the complexity and well depth increases, creation of an efficient and reliable window in one trip becomes challenging. Semi-submersible/floaters and jack-up rigs does always hold a wireline unit on board since it adds to the operational cost. (Fang, Dahlberg, Lydvo, & Olsnes, 2016)

Solution 1:

This could be a future solution to the above operational issue. ASM and EMS until now do not hold the function to locate the casing collar ((EMS), March 8, 2017; Measurement, March 8, 2017.). The possibility of developing such an application in one of these tools where locating the casing collar, placing the whipstock, side track and drilling to a desired formation in one run would benefit the future operations in the NCS(Fang et al., 2016)

Problem 2:

Vibrational issues:

Until now only BHA dynamics has been studied since the implementation of downhole measurement tools. However, the recent studies prove that the upper part of the drillstring faces vibrations that could result in drillstring failure. However, this is based on the well geometry and the operations conducted (Chen et al., 2018; J. D. Macpherson, Paul, Behounek, & Harmer, 2015).

Solution 2:

The introduction of ASM in the drill string and the BHA provide the possibility to study the dysfunctions in the complete string and a comprehensive view on the drill string dynamics. In operations such as fishing, milling etc. where the vibrational issues are of higher concern, ASM might provide optimum operational limit of vibration. From the case study 3 in section 3.3, it is inferred that the upper part of the drillstring experience similar or even higher vibrational issues as the BHA section during side tracking / casing exit jobs(Cardy et al., 2016). This could be beneficial to avoid drillstring failure.

Problem 3:

Casing Leak:

Some mature wells have undergone casing wear which has resulted in minor casing leaks. Expensive service tools such as RTTS packers are used to estimate the leak point.

Solution 3:

When running the AMS/ EMS tool along with WDP, there could be a possibility to sense changes in fluid properties/dynamics across suspected leak formations. If this application could be further developed to study the minor leak points in the casing, then this negates the use of expensive pressure equipment or use of mechanical packers (RTTS packer) to detect leak points in casing. Moreover, it could be possible to exactly pinpoint the location of leak in the casing/tubing during a conventional cleanout run. This would be perfect for applications in mature wells. Based on the data collection, a future course of corrective action can be devised to fix the leak(Cardy et al., 2016).

Problem 4:

Packer Integrity/ Borehole caliper measurement:

In mature wells, corrosion could be a usual operational issue. It requires borehole caliper logging or cement bond logging to know the integrity of casing before packer setting. Because of mechanical friction between drill string tool joint and casing, it is commonly observed, that part/section of the casing being removed. Figure 4.18 illustrate the casing wear phenomenon due to string rotation and the applied contact force.

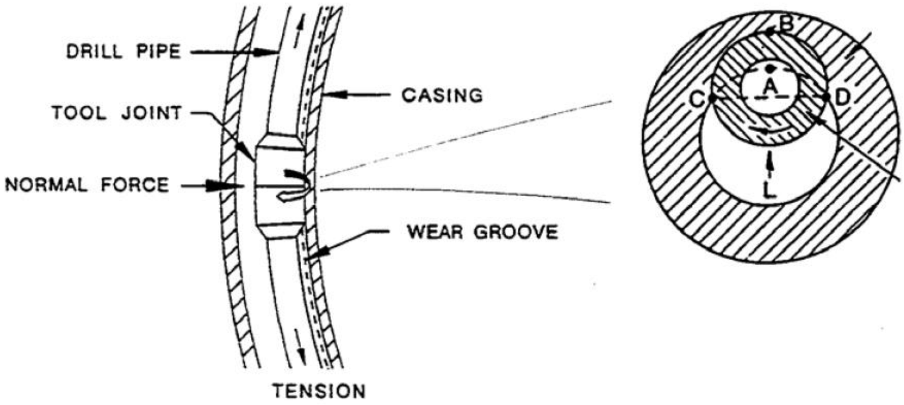

Figure 4.18. Casing wear caused by drill string rotation (Wu & Zhang, 2005)

Figure 4.19 displays the measured casing wear in Gullfaks A-42, which shows about 30% wall thickness removal due to connection and casing interaction. (Wu & Zhang, 2005)

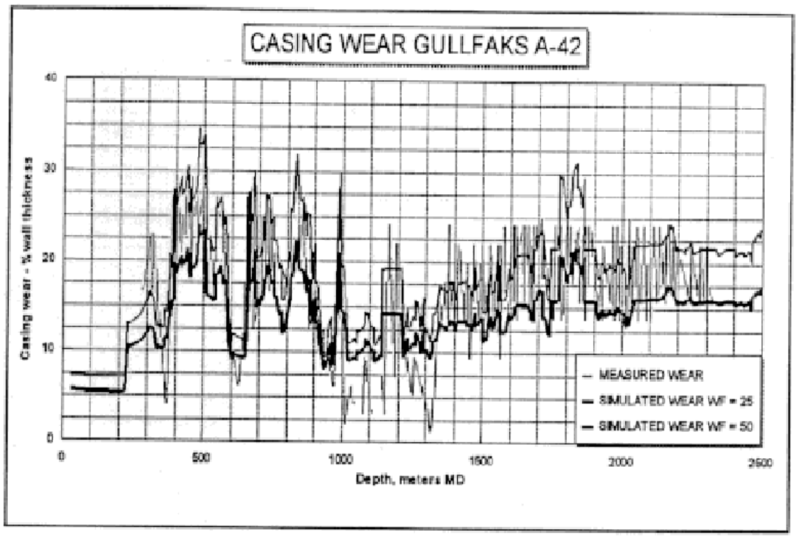

Figure 4.19. Casing wear in Gulfaks (Wu & Zhang, 2005)

Packer placement at highly wear place or corroded part of the casing, is likely to expect poor packer-casing seal integrity and hence, in the long-term packer leakage may occur. Packer failure/leakage has been documented in several well in NCS (Vignes & Aadnoy, 2008) and in Alaska(Julian, Sack, & Johns, 2007)

Solution:

To avoid the logging trips, there could be a replacement of logging tools with WDP and wired BHA that could function as a logging tool and send real time data to the surface. Based on the real-time caliper log data, one can evaluate the log and select the undamaged or optimum casing location for packer placement, and the packer will be set on with the same drillstring. This operation allows just one run (i.e. logging and packer setting in single trip). By doing this, it is possible to achieve the maximum shelf life for the packer and ensure casing integrity. This reduces undesired logging related tripping operations. In other words, this solution will reduce the NPT for an extra logging and maintain undesired packer leakage at early stage after re-completions/ workover.

Problem 5:

Depleted Reservoirs

Side tracking and re- completions of MLT (multilateral) wells which have depleted reservoir is a challenge due to the very limited drilling operational window. A field which is already in production such as Snorre could have both the pore pressure and the stress reduced. A pure theoretical approach will not help in understanding the drilling operational window. (ASA, 22.10.2004, 2006-09-21; Reservoirs, 2019)

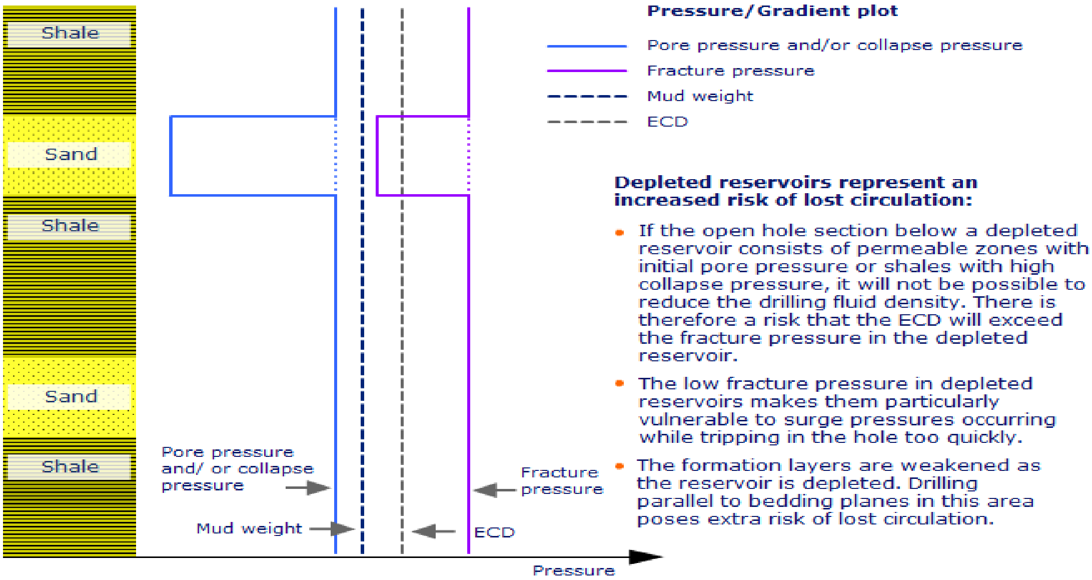

Figure 4.20. ECD effect in depleted zones (ASA)

Solution 5:

WDP overall benefits could improve the ability to drill through severely depleted zones. An improvement in the methods currently devised to understand the formation stress in open hole should be revised. That is continuous real time availability of formation stress and temperature downhole. The introduction of ASM in the drill string and the BHA provide the possibility to study the dysfunctions in the complete string and a comprehensive view on the drill string dynamics.(Reservoirs, 2019)

5 SUMMARY AND DISCUSSION

The advantage of the wired pipe is significantly high with the measurement tools available today. There is no downside while using WDP in any operational activity such as dart during cementing or dropping ball for completion. (Foster & Macmillan, 2018)As discussed, operators could benefit if wired pipe project is adopted in their workflow.

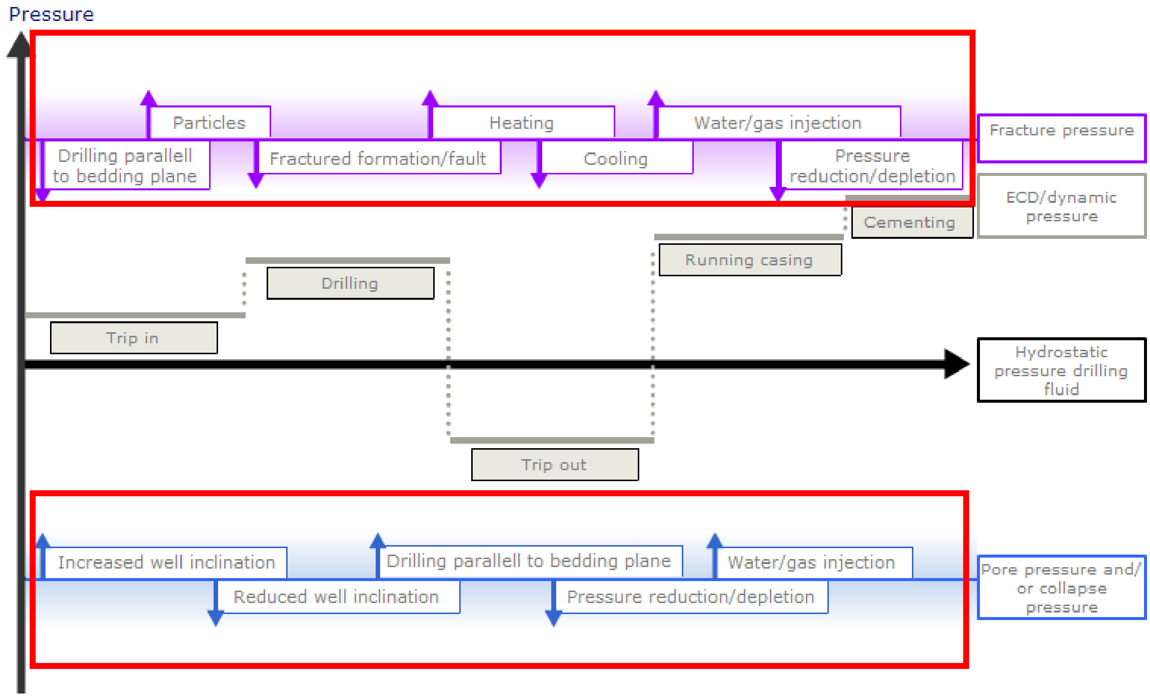

Figure 5.1. Operations involving drill pipes that can be replaced with WDP

The well activities shown in the figure 5.1 are all carried out using drill pipe at some stages of the operation. The factors affecting the operations are marked in red boxes. The application of ASM and EMS with WDP provides real time data that could improve the conventional practice presently used in the industry.

<u>Overview of benefits of wired drillpipe</u>:

Since the downturn in the oil industry from 2015, operators in offshore industry have been focusing on time efficiency especially during drilling operations. The industry where personnel and equipment are charged with day-rates, time efficiency is an important aspect. Some of the advantages of WDPT network are as follows(Fosse, 2015) :

A) Run Reduction:

The data being received can interpret the downhole condition and if there is any possibility of unexpected tool failure. E.g. The drill string experience high lateral vibrations during backward whirl. This can damage the BHA, resulting in unwanted tripping activities.(Solem, 2015)

B) Trip Optimization:

This thesis has a priority in this topic although the applications of WDPT is not much studied in this area. However, time savings while POOH/ RIH are still plays a significant role. Trip-out operations after TCP (tubing conveyed perforation) jobs are very slow since the well is live (as discussed in 4.3.7). An increase in the trip out speed can result in swab effect, thus inviting unwanted formation fluids into the well, concerning the safety of operation. An important feature that will help in the trip optimization in the future is ASM, which has been discussed in previous chapters. (Israel et al., 2018a, 2018b)

C) Real time- geomechanically and geological interpretation:

Along with sending downlinks (near- instantaneous commands) to the RSS and MWD tools, WDPT has allowed transmission of high quality LWD data to the surface in real time (Wilson, 2013). Memory quality logs are available. LWD resistivity imaging and azimuthal imaging tools are commonly used with WDP. Since azimuthal density tool rotates around the circumference of the wellbore, a density image could be obtained. This is useful in deciding the hole size variations and hence the wellbore stability. The combination to see the geology and the pressure in the annulus without breaking down the formation has helped drillers to geo steer effectively. An operator in North Sea, could go further in the hole and the operation used one lesser well on that development to drain the reservoir. This was due to the potential to drill longer reservoir section lot more efficiently (Foster & Macmillan, 2018). A higher quality density image could further help in fault identification. This is critical when drilling from fault to fault, since there could be heavy losses in well and there will be requirement to pump in LCM. Also, in a certain field, identification of such faults with WDP helped geologists to update their planned trajectory to reach the target with optimal length of reservoir. The use of WDP, thus avoided any geological sidetracks(Fosse, 2015).

D) Wellbore Stability

When the cuttings in the annulus is managed, then the pressure in the annulus is indirectly managed which improves the quality of the wellbore. Also, BHA vibration have an important role in getting an accurate borehole quality. WDP enhances the directional drilling and helps in pointing the bit in right direction from geological point of view and not the planned one(Schils et al., 2016; Selheim, Morris, Jonsbraaten, Aarnes, & Teelken, 2017). The useful application to rightly see the shape and size of the hole being drilled is much appreciated by the industry professionals since obtaining a good quality hole undoubtedly drives down the cost by decreasing the time spent in wiper trips, hole cleaning etc. Low and compressed density image is sent to the surface with the use of MPT which cannot provide adequate value in interpreting the wellbore uncertainties (Solem, 2015).

E) Tool diagnostics and downlinking

Understanding the tool behavior towards the formation that is being drilled helps in avoiding unnecessary trips due to tool failure. Also, in cases where tools are partially damaged, and their functionality is decreased, this understanding sometimes support to continue drilling further to that section TD by controlling the drilling parameters and thus avoiding unnecessary trips. WDP provided this understanding to Statoil in the field trials(Selheim et al., 2017). WDP does not require any surface equipment/pumps or mechanical interface for downlinking. Through WDP, commands are instantaneously sent and received at the stoke of a key. This has sometimes allowed the drilling crew to leave their downhole tools at the bottom even while drilling challenging sections. The facility to execute limitless instant downlinking along with high level of commands over the BHA has many advantages. WDP mostly benefit in those cases where it may not be possible to reach the planned trajectory, or the time required for it might be much longer(Wilson, 2013).

F) Advantages of ASM in the drillstring are as follows:

- **Cutting Transportation and Hole Cleaning:**

An ability to know the position in the string where cuttings accumulation is present can help in optimizing the flow rates. This will reduce the time spent in circulation of well at TD(Stephen T. Edwards et al., 2013). In MPT, the data can be located only at the BHA of the string. Placement of ASMs along the drillstring provides much better information of the solids that are transported to the surface. The pressure sensors in the annulus helps to determine the accumulation of wellbore solids and its transportation to the surface. For improving the solid transportation along the annulus, high density sweeps are often used. As sweep moves along the annulus, the cuttings are held in suspension by the action of the buoyancy. The multiple sensors in the string provides a detailed investigation of the sweep efficiency (Wilson, 2013).

- **Data availability when pumps-off:**

Not only the amount of data provided by the wired pipe but the reality that the downhole data can be achieved when pumps are off, play the most significant role. This is one of the major constraints of mud pulse telemetry where if pumps are off no downhole communication could be achieved. Due to the presence of battery powered booster subs, downhole communication could always be established irrespective of the state of pipe. The pressure applied during leak off test is very sensitive to fracture initiation. Hence it is important to know the frequency of downhole pressure during LOT. In this case the availability of high frequency real time downhole data demonstrates very practical downhole image while conducting the leak of test. Ballooning/ borehole breathing is studied based on the characteristics of the annular pressure downhole. This could be performed during connections. These measurements were generally received only after getting the tool memory data after operations. WDP provides the data if the top drive is connected. This helps in distinguishing kick and ballooning scenarios. During situation of sidetrack, at certain times the requirement for flow rate is low. WPD could be useful in providing real time downhole dynamic data. During intervention or completion activities, downhole torque and load can be determined with the application of WDP along with EMS. This provides an indication if the tools are hung up/ correctly positioned in highly deviated/ ERD wells. Generally, kick is identified during connections. At this situation, the pumps are off, and the well is at static conditions. When kick is identified, the well will be shut-in. Following this, proper well control method will be used. However, any procedure will demand the circulation of fluid at certain rates to displace kick out the well. Often this involve no communication with the downhole measurement tools (pressure and temperature). By using WDP, the measurement can be received from different points in the drillstring. This data will increase the well control procedure(D. Veeningen, 2013). Looking beyond well control, other high benefits of WDP is in MPD operations(D. M. Veeningen & Adsit, 2013). While drilling through faults, it is usual to get heavy mud losses. Here, LCM will be pumped to prevent further losses to the open hole. Pumping drilling fluid through WDP along with ASM will help to determine the loss zone. Certain other situation, where loss rate exceeds the fluid circulation rate, there will not be any returns to the pump. In this case, it is unsafe to drill as the hydrostatic pressure in the well drops below the formation pressure leading to kick situation. When flow rates are controlled in an operation, MPT will not be very effective. However, WDP will provide the measurements of annular pressure (mud column height can be calculated) and provide means to stop the annular pressure from dropping below formation pressure (Sehsah et al., 2017).

- **Downhole events detection:**

The distribution of several sensors (ASM) along the length of the drillstring provides a much better accuracy for the determination of downhole events. When annular pressure data is received real time, the location of the downhole event could be determined by looking at sensor indicators. E.g. In a situation where there is total loss of fluid with no returns to the surface, ASM could help in early downhole detection. Such total losses are experienced when drilling activities are carried out in HPHT wells. The measurement of dynamic pressure and bottomhole hydrostatic by the ASM could also provide indications for early kick detection(Wilson, 2013).

- **WDP forming an integral part of Automated Drilling Control (ADC) Systems operation:**

The recent studies prove that Automation Operating System (AOS) and wired drillpipe (WDP) provides a well-defined and complementary functionality for well operations. The system focused on the delivery of the following capabilities.(ASA, 2018b; Jacobs, 2019)

- High speed telemetry.
- Closed-loop-drilling management.
- Distributed sensors: Along String Measurements.

The cluster of technologies from Sekal AS, NOV and MHWirth incorporates in Transocean rigs for Equinor ASA benefits

- avoiding swab/surge effects.
- higher penetration rates while drilling.

- early kick/loss event detection.
- highly stable bottom hole pressures. (ASA, 2018b; Jacobs, 2019)

Uptime of wired drill pipe: As of 2015, nearly 100 wells have been drilled using the 1st generation wired drill pipe, giving an uptime of 91% (Solem, 2015). The important aspect of this technology is the ability to send and receive real time data without any flow in the well i.e. in loss circulation or tripping operations. Wired drill pipe enables surveys to be transmitted instantaneously and can be activated before connection or mid stand without the need to cycle the pumps and wait for the data to be transmitted saving several minutes per connection. Rotational checkshots often required with each new BHA are completed in a matter of minutes with the two-way communication provide by wired drill pipe saving up to an hour of rig time compared to conventional two techniques. Orienting a bent motor for slide drilling can be performed quicker with the availability of high frequency tool face data, saving up to several minutes per slide. Sending downlinks to rotary steerable tools typically require varying the flow rate for up to 10 minutes. With wired drill pipe, downlinks can be sent instantaneously, avoiding the need to slow or stop drilling. Conventional telemetry systems can introduce ROP limits because of slow data transfer speeds such as LWD data density, directional control or ECD management. With high speed data, these limiters can overcome and higher ROP could be achieved. Critical downhole shock and vibration data is transmitted at high speed with wired drill pipe enabling damaging events to be quickly mitigated and drilling performance to be continuously maximized. The small but frequent time savings result in significant well delivery time reduction(Solem, 2015). WDP has the potential to give continuous commands to the geosteering tool that adjusts the wellbore trajectory with a smaller number of corrections. This provides a better-quality hole with less dog legs, hence reducing the risk of tool damage and casing stuck issues while RIH(Wilson, 2013). (Solem, 2015)

6 CONCLUSION

The primary objective of this thesis was conducting case studies of fields where wiredpipe technology was utilized. Based on the studies, proposed possible alternative applications that can be inferred and developed from WDP technology along with implementation in the future field development of Equinor ASA assets such as Snorre Expansion Project(Project), 2019). The main key findings along with the concluding remarks will be presented below.

6.1 Summary of the key findings

A total of eight field case studies and application of the wiredpipe technology has been reviewed. The studies have shown a great improvement with the wiredpipe technology over the conventional methods telemetry such as MPT. WDP allowed real time data to be extracted from the latest MWD, LWD and rotary steerable systems. This have not only helped in precise control of BHA, geosteering and drilling dynamics but also developed a different approach in formation evaluation process. The main factors that contributed to the successful WDP implementation are as follows:

- Increased drilling rates by ROP optimization.
- Decreased downhole tool failures.
- Improved UBO and MPD operations.
- Controlled downhole WOB.
- Improved real time downhole monitoring.
- Early kick detection and wellbore stability controls.
- Optimized of hole cleaning.
- Reduction in wireline operational requirements.
- Increased reservoir exposure.
- Smoother borehole profiles facilitated liner and lower completion jobs.
- Reduction in NPT by decrease in tripping jobs.
- Innovated seismic-while- drilling and reamer activation technology.

Table 6.1 shows the main challenges with the conventional methods of well operation and how it could be solved by using the WDP network system.

Case study	Field Name Location	Operation and challenges involved		WPD Solution	Reference
		Operation	Challenges	Benefits	
1	Babbage Field Cental North Sea, UK	Drilling	➢ Downhole pressure fluctuations ➢ ROP Limitation ➢ Tool Failures	➢ Early detection of drilling dysfunctions ➢ Improved well placement due to ideal trajectory control ➢ Reduced bottomhole tool failures, hence decreased tripping time. ➢ Precise understanding of downhole drilling environment ➢ Optimized hole cleaning process	(Teelken et al., 2016)
2	Martin Linge Field North Sea, Norwegian Sector	Drilling MPD Operation	➢ Complex reservoir ➢ Drilling challenges such as shock and vibrations, high losses etc. ➢ Poor MWD/LWD signal transmission ➢ Hole cleaning in deviated section	➢ Instant activation of dual reamers. (new technology) ➢ Monitoring ECD close to the casing shoe during MPD. ➢ Optimized hole cleaning process due to the presence of ASM ➢ Time saving ➢ Detection of reservoir formation ahead of the bit	(Schils et al., 2016) (NOV for Total E&P)

3	North West Shelf Offshore, Australia	Side- Tracking	➢ Vibrational Issues ➢ Drillstring Failure	**This field did not use WDP system.** If WDP along with ASM were used, real time vibrational data downhole (contact point between casing and drillstring) could be received, mitigate drillstring vibrational issues	(Cardy et al., 2016)
4	Onshore, Middle East	Drilling Study	➢ Kick ➢ Low density image data (Data gaps) ➢ Downhole pressure fluctuations	➢ Faster detection of swab and surge pressures ➢ Kick detection ➢ Fluid/ Mud level detection ➢ Loss zone depth estimation ➢ Continuous monitoring of BHP	(Sehsah et al., 2017)
5	Troll field North Sea, Norway	Drilling	➢ High doglegs caused while drilling through calcite stingers, results in low ROP and BHA failures ➢ Less availability of drilling data	Enabled ➢ Early detection of high doglegs ➢ Immediate adjustment in drilling parameters to mitigate the severity of high doglegs	(Denney, 2008; Nygard et al., 2008)
6	Elk Hills, Kern County California, USA	Drilling	➢ Pore pressure management and ECD issues due to the low permeability formations ➢ Stick slip, shock and vibration tendencies ➢ Limited downhole tool communication	➢ Faster means of real time bi-directional communication in foam drilling fluid saving 10 to 12 % of drilling time. ➢ Employed underbalanced drilling using foam drilling fluid along with achieving high resolution of downhole data in real time	(McCartney et al., 2009)

			and measurement availability		
7	Trinidad fields Offshore Trinidad and Tobago	Drilling	➢ Soft sediment formation resulted in excessive wellbore instability ➢ Limited downhole density data to estimate borehole instability	➢ Availability of high-resolution gamma ray images of the wellbore in real time. ➢ Early detection of well instability issues such as pack off, caving etc.	(Stephen T. Edwards et al., 2013)
8	Prudhoe Field, Alaska	Drilling Possible Other Operations Studied	➢ WDP version V1 reliability issues	<u>Evaluated benefits of V2 verion of WDP.</u> 1.Development of closed loop drilling parameter system ➢ Downhole WOB control ➢ Downhole ROP optimization 2.Along string measurements for ➢ Vibrational control ➢ Pressure and temperature 3.Telemetry time savings ➢ Surveying ➢ Downlinking ➢ Real-time memory quality data	(Israel et al., 2018a, 2018b)

Table 6.1. Limitations of conventional method and WDP solutions.

6.2 Concluding remark of alternative WDP applications

The prospective advantages of the WDP network along with the progressing downhole sensor expansion and the growing difficulty to drill ERD wells in depleted reservoirs suggest that this improved technology could become a game-changer in drilling automation industry. SEP project being an important prospect for Equinor ASA and Norway might initiate other possible operations with WDP.

As discussed in Chapter 4, the future applications are summarized in Table 6.2:

Operations	**Possible future benefits of WDP that requires further research and evaluation.**	**References/ Discussed section**
Tripping	- Live evaluation of swab and surge model in the process of any well operations. - WDP network to foresee the cooled injection zones.	(Israel et al., 2018a, 2018b) Section 4.3.2
Cementing	- Liner cementing applications. -Annular pressure while cementing.	(EMS; Israel et al., 2018a, 2018b) Section 4.3.3
Wellbore Cleanout	- To measure fluid properties in well (ESD or ECD) and confirm clean out. - Placement of EMS have better control of downhole torque during WBCO with rotation.	Section 4.3.4 Section 4.3.5
Perforation	- To develop further application to confirm if guns have detonated. - Follow trip speed from actual data/ real-time data.	Section 4.3.7
Completions	- To develop further application of accuracy caliper tools, to measure ovality or areas for packer setting. -Mechanical set downhole tools that require load and rotation to set. -Better understanding of downhole conditions during. ➢ liner jobs. ➢ open hole completions.	Section 4.3.8

Side Tracking	- locating casing collar. - detection of casing leak points. - mitigating drillstring failure due to vibration. - drilling in the exact operational window in depleted reservoirs.	Section 4.3.9

Table 0.1. Possible benefits with WDP for SEP

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Appendix

For interested readers, the tables are taken from (J. Macpherson, Roders, Schoenborn, Mieting, & Lopez, 2019)

A1 Effect of WDP telemetry on drilling systems-control, performance and cost

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Table 1—The effect of wired pipe telemetry on drilling systems – control, performance and cost

Systems Control, Performance and Time Savings	Sources
Systems Control Fast downlinks and control of downhole tools; active and immediate control of the downhole drilling system; RSS control; formation pressure tester control; closed loop control of downhole WOB; effective slide control; reamer activation; survey check shots on demand; process automation; leak-off test control; automation control sequences	Edwards et al. 2013 Lawrence et al. 2009 Israel et al. 2018 Lesso et al. 2008 Nygaard et al. 2008 Pink et al. 2013 Pink et al. 2017 Schils et al. 2016
Time/Cost Savings Downlink time savings; reduced directional surveying time; downlink on demand; avoid unnecessary trips due to full knowledge; reduction in connection time related to surveying; fewer bit and BHA runs; telemetry time savings (consists of Gyro/MWD surveys, MWD survey at connection, survey check mid-stand, RSS downlink, slide orientation, FIT/LOT transmission, LWD downloads)	Israel et al. 2018 McCartney et al. 2009 Nygaard et al. 2008 Schils et al. 2016 Teelken et al. 2016
System Performance Faster drilling, ROP improvement and optimization, consistency; tangible benefits in improved drilling performance; downhole drilling information alongside surface information in real-time; drilling optimization; real-time information improves drillers and drilling teams; real-time drilling dynamics and mechanics; systems approach to drilling; early (low latency drilling dynamics); automation using wired pipe to improve overall performance	Israel et. 2018 Edwards et al. 2013 McCartney et al. 2009 Nygaard et al. 2008 Pink et al. 2013 Schils et al. 2016 Teelken et al. 2016 Trichel et al. 2016

A2 Effect of WDP telemetry on drilling application related to wellbore

Table 2—The effect of wired pipe telemetry on drilling applications related to the wellbore

Wellbore Related Applications	Sources
Wellbore Quality and Placement MWD survey quality improvement; directional control improvement; micro-geosteering with RSS to maintain tight TVD control; better dogleg and turn rates; reduce wellbore tortuosity (mitigating high local DL); seismic (full waveform) ahead of the bit 200m; improved sand (reservoir) exposure per well; optimum trajectory control and improved wellbore placement (LWD images, RSS downlink and control); memory quality formation evaluation data in real-time; real-time geological and geomechanical interpretation; BHA tendencies and dynamics – high dogleg on intersecting stringer;	Edwards et al. 2013 Lawrence et al. 2009 McCartney et al. 2009 Nygaard et al. 2008 Schils et al. 2016 Teelken et al. 2016
Wellbore Stability and Cleaning Real-Time imaging for wellbore quality and stability; real-time geological and geomechanical interpretation; along string pressure sensors for hole cleaning and solid transport; analysis of high density sweeps; along string pressure sensors for hole cleaning and solid transport; location of pack-offs; better monitoring of downhole pressure data	Edwards et al. 2013 Lesso et al. 2008 Schils et al. 2016
Wellbore Control Monitoring ECD during break over from fluid to foam; formation pressure test and leak-off tests; wellbore control; use of PWD data in real-time to update a hydraulic model in MPD operations; MWD with UBD, foam, flow independence	Israel et al. 2018 Edwards et al. 2013 Fredericks et al. 2008 McCartney et al. 2009