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Detection of Bit Wear in Sandstone and Conglomerate

Analysis of Drilling Data and Formation Characteristics

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Summary

When drilling in challenging formations the drill bit experiences wear to some extent, which may lead to a reduced rate of penetration. Since the drilling costs are so high, it is desirable to be able to detect bit wear in order to make actions to optimize the drilling process, extend the bit life and bit runs.

The aim of this master thesis was to investigate whether drilling data and formation data could be used to detect bit wear when drilling sandstone and conglomerate intervals. If trends and patterns were recognized in the data available, the results could be used to investigate and detect bit wear when drilling other wells, which could optimize the drilling process.

The calculations and evaluations performed are based on the statement that a higher weight on bit needed in order to achieve the same rate of penetration when drilling the same formation characteristics, is an indication of bit wear. Another statement expressed by drilling engineers and geologists in Lundin Norway, was that the bit experiences more aggressive wear and more drilling related problems when drilling conglomerate sections compared to sandstone. Drilling data and formation data from two productions wells at the Edvard Grieg field was used to investigate whether these data are sufficient in order to detect and recognize bit wear according to these statements.

After evaluating the reservoir sections in both wells, the same trends and patterns were detected. When the bit was worn, the weight on bit needed to be higher in order to achieve the same rate of penetration. The investigation also confirmed the statement that the drill bit experiences more aggressive wear when drilling conglomerate sections compared to sandstone. Therefore, it was concluded that drilling data and sub-surface data are sufficient in order to be able to detect bit wear. Since the patterns in the two wells are so evident, it was concluded that these evaluations and results are applicable in other wells when drilling the same lithology.

The results presented could potentially be used when optimizing the drilling process of other wells. If the same trends detected through this evaluation are recognized in a new well, the bit can be pulled earlier which could result in an overall higher rate of penetration and a more stable drilling process.

In the future, the industry should strive to optimize the way of drilling challenging conglomerate intervals, to extend bit life. Analysis of downhole drilling data should preferably be performed in order to find a more effective way of drilling such intervals. Investigation of more wells could be used to validate the results from the investigations performed in this thesis.

Sammendrag

Ved boring av tøffe formasjoner vil borekronen og annet boreutstyr oppleve slitasje, noe som kan føre til en redusert borehastighet. Siden borekostnadene er så høye, er det ønskelig å kunne detektere slitasjen på nedihullsutstyret slik at tiltak kan iverksettes for å optimalisere den videre boreprosessen og forlenge levetiden til borekronen.

Formålet med denne masteroppgaven var å undersøke om boredata og formasjonsdata kan benyttes til å detektere slitasje på borekronen ved boring i konglomerat og sandstein. Dersom det blir detektert trender i de tilgjengelige dataene, kan disse bli brukt til å evaluere og gjenkjenne slitasje på bit i andre brønner. Dette kan potensielt føre til en optimalisert boreprosess.

Beregningene og undersøkelsene som er blitt utført er basert på teorien om at dersom det trengs høyere vekt på bit for å oppnå samme borehastighet, er det indikasjon på at borekronen begynner å bli slitt. En annen påstand uttrykt av boreingeniører og geologier i Lundin Norway var at boring i konglomerat sliter mer på borekronen og at det lettere oppstår problemer med boringen enn ved boring i sandstein. Boredata og formasjonsdata fra to produksjonsbrønner ved Edvard Grieg feltet er blitt analysert for å se om slike data er tilstrekkelig for å detektere slitasje på bit med bakgrunn i de nevnte teoriene.

Etter å ha evaluert reservoarseksjonen i som besto av både sandstein og konglomerat, har de samme trendene blitt detektert i begge brønnene. Når borekronen er slitt, trengs det høyere vekt på bit for å oppnå den samme penetreringsraten når identisk formasjon sammenlignes. Analyse av dataene har også bekreftet teorien om at borekronen opplever en større slitasje ved boring i konglomerat sammenlignet med sandstein. På bakgrunn av dette er det konkludert at en kombinasjon av boredata og formasjonsdata kan brukes til å detektere slitasje på borekronen. Siden trendene i disse brønnene er så fremtredende og tydelige, er det slått fast at resultatene fra denne evalueringen kan brukes til å analysere andre brønner når det bores i sandstein og konglomerat.

Resultatene fra denne undersøkelsen kan potensielt brukes til boreoptimalisering av nye brønner. Hvis de samme trendene som ble observert i denne evalueringen blir detektert i nye brønner, kan borestrengen bli trukket tidligere, noe som kan føre til en høyere borehastighet og en mer stabil boreprosess.

I tiden fremover bør industrien jobbe mot å finne en optimalisert måte å bore intervaller med konglomerat på for å øke levetiden til borekronen. Ideelt bør nedihullsdata fra boreprosessen analyseres for å komme fram til en effektiv måte å bore slike intervaller. Resultatene fra denne masteroppgaven kan valideres ved å undersøke flere brønner.

Acknowledgement

This master thesis have been prepared in cooperation with Lundin Norway AS. The topic for present thesis is a combination of the company's interests and my academic background. I am grateful that I got the opportunity to work with a topic that are of great importance to the company and the industry, and that also align with my personal interests and knowledge.

Without exception, everyone I talked to at the Lundin office were enthusiastic and all willing to share his or her knowledge with me. Discussions with highly experienced geologists and petrophysicists helped me to improve my knowledge and understanding of the downhole environment needed to work with this topic. I would like to use the opportunity to thank several people within the company. Odd Aasheim, Andy Clark and Lillian Julseth provided me with all necessary sub-surface data and guidance I needed to perform the calculations and evaluations in this thesis. I am very grateful for all the help and support I received.

I would also like to give a special thanks to Espen Hoel for providing good support and help improving my technical understanding regarding drilling. All our discussions and your commitment helped me in the process of finishing this master thesis.

My supervisor at NTNU, Sigbjørn Sangesland, has also guided me in the process of writing this master thesis and I am grateful for your help and support.

Finally, I would like to express my gratitude towards my classmates and fellow students for being motivating and supporting.

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1 Introduction

Drilling wells, especially from offshore locations, are expensive and if hard and challenging formations such as conglomerate are encountered during drilling, it could lead to extensive wear and damage to the drill bit and downhole equipment. If the bit gets worn out or not capable of remaining progress, it would cause an extra bit trip, which again would increase the drilling costs significantly. A better understanding of the downhole conditions in these formations would improve the drilling operation and reduce the drilling costs. Real-time detection of bit wear during drilling could optimize the drilling process and provide a tool in order to make actions that would result in an overall higher rate of penetration. If the drilling parameters were optimized when drilling in challenging formations, the bit wear could be reduced and the bit-life extended.

The aim of this master thesis is to investigate whether drilling data and formation data can be used to detect bit wear when drilling sandstone and conglomerate intervals. If trends and patterns are recognized in the data available, the results can be used to investigate and detect bit wear when drilling other wells, which can optimize the drilling process.

The rate of penetration (ROP) achieved during drilling is a product of several different factors, both controllable from surface and determined by the downhole environment. The relationship between these are complex, therefore some mathematical models are developed in order to investigate how the rate of penetration is affected by the different variables. These models can be used to optimize for instance the weight on bit and rotational speed (RPM) in order to achieve the minimum cost per foot drilled. Only the most accurate models are discussed in this thesis.

The calculations and evaluations performed are based on the statement that a higher weight on bit (WOB) needed in order to achieve the same rate of penetration when drilling the same formation characteristics, is an indication of bit wear. Another statement expressed by drilling engineers and geologists in Lundin Norway, is that the bit experience more aggressive wear and more drilling related problems when drilling conglomerate sections compared to sandstone. Sub-surface data and drilling data from two production wells at the Edvard Grieg field will be evaluated to investigate whether such data are sufficient in order to detect bit wear according to these statements.

Real time surface drilling data is used to establish an average ROP and surface WOB. Only one of the two wells had downhole drilling data available and an additional average downhole WOB will be calculated for this well. The reservoir section of both wells consist dominantly of sandstone and conglomerate and the calculations will be performed on these two lithologies separately. The evaluations performed and the conclusions are based on these average calculations.

The relationship between drilling data and formation data is evaluated to detect similarities and correlations between them. This is to confirm whether a combination of these data can be utilized to identify bit wear in the two wells evaluated.

2 Field and well information

2.1 Location

The data from the two production wells are both from the Lundin Norway operated Edvard Grieg Field in the North Sea. The Edvard Grieg field is located in the production license PL338 in the North Sea approximately 180 kilometers west of Stavanger. Both wells are drilled with the jack-up rig Rowan Viking. The water depth at the location is 109 m. From now on will the two wells be referred to as Well A and Well B.

2.2 The Edvard Grieg Field

The Edvard Grieg Field is located on the southern part of the Utsira High. The oil production from the field started according to plan in November 2015. The field is expected to produce at plateau during the second half of 2016. In addition to the production wells at the field, there are planned four water injectors dedicated to provide pressure support. The reservoir fluid at Edvard Grieg is a moderately undersaturated oil with a low gas-oil ratio (LundinNorway, 2013).

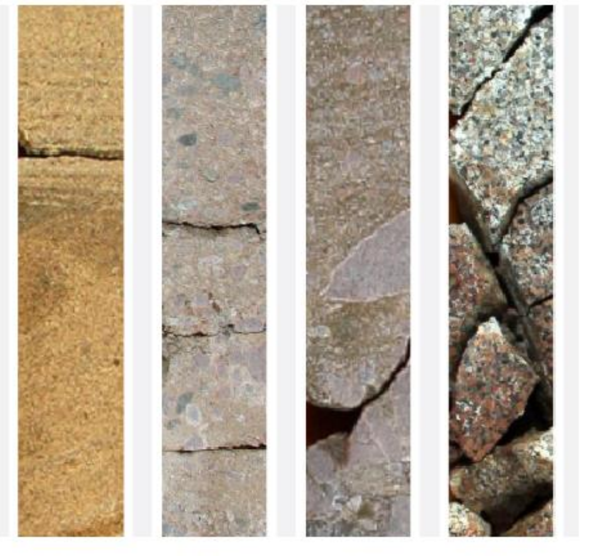

Figure 2.1: The different reservoir rocks at the Edvard Grieg Field (LundinNorway, 2013)

The reservoir, which is situated at approximately 1900 meters depth, consists of two different reservoir segments, Luno and Tellus. Both segments consist of calcareous rich cretaceous sandstone overlaying zones that contain rocks with more uncertain flow potential. In the Tellus segment in the north, a thin sandstone layer is overlaying an old fractured and weathered basement rock depicted in Figure 2.1 (d), consisting of a 48 m oil column. The main part of this segment consists of conglomerate and sandstone illustrated in Figure 2.1 (b)-(c). The central part of the Luno discovery consists of a 50 m thick aeolian sandstone with excellent reservoir qualities as depicted in Figure 2.1 (a). More than half of the total reserves from Edvard Grieg are from this sandstone zone. The reservoir rocks described spans in age from 140 million years all the way up to 440 million years old (LundinNorway, 2013). There are proven pressure communication between the two segments, Tellus and Luno.

2.3 Well objectives

The overall purpose of Well A was to produce oil from the central area of the Edvard Grieg Field, from high permeable sandstone in the Skagerrak formation. The well was successfully landed horizontally in fluvial dominated sandstone in this formation. This producer was drilled to ensure areal sweep to the north. The well drilled 831 m of reservoir section with an average porosity of 22% (LundinNorway, 2015a).

The objective of Well B was to produce oil from the Southern part of the same sandstone zone as Well A. The well was designed as a horizontal well targeting the sand rich section in the upper part of the Triassic. A pilot well was drilled to provide stratigraphic information for optimizing the landing and placement of the horizontal section of Well B (LundinNorway, 2015b).

3 Formation issues and consequences

3.1 Formation characteristics

When drilling Well A and B, both soft and hard formations were encountered. The hardness of the rock is dependent on many factors, for instance the degree of cementing. The more cemented the rock is, the harder it turns out to be. Another factor affecting the hardness of the rock is the mineral composition. Presence of feldspar and high clay content will give a reduced hardness compared to clean quartz sandstone. Other causes might be the crystallization of the rock, metamorphosis and boulders (Solberg, 2012).

There are three main classifications of rocks; igneous, metamorphic and sedimentary. Only the sedimentary rocks are described since the reservoir sections of the wells evaluated in this thesis mainly consist of sedimentary rocks.

Through compaction and cementation, will sediments from weathered rocks accumulate and form clastic sedimentary rocks such as conglomerate, sandstone and siltstone. In addition to clastic sedimentary rocks are biogenic sedimentary rocks formed as a result of activity by organisms and precipitates which is a result of seawater evaporates. As mentioned, the mineral composition of the sedimentary rocks determine the hardness. Some of the most common minerals in these rocks are quartz, feldspar, calcite and clay group mineral (Schlumberger, 2016d).

The best reservoir rocks are sandstones with high porosity and permeable. Sandstone consists of predominately quartz with the size of sand grains (1/16 – 2mm in diameter) and a cementing material to bind it all together. Usually sandstones are hard, homogenous rocks that are compacted and formed as described above (Schlumberger, 2016c).

Not all rock types are homogeneous with respect to hardness, which can cause difficulties when estimating tool wear and during the bit selection process. The clastic sedimentary rock conglomerate is one of the formation types that contain the greatest variation in hardness within the same rock.

The geological settings need to be correct in order for conglomerate to be formed, which includes a water flow to be able to transport large fragments and a source with a variety of sediment sizes need to be present somewhere up-current in the water flow. Breakdown of smaller clasts and a rounding process of larger clasts are possible with the presence of the flowing water. The water flow also contributes in the process of making small particles into a slurry that is used to fill the space between the larger clasts (Pier, 2016). This results in a rock containing a wide range of different sized particles, from small pebbles which have a diameter of more than 4mm, to boulders larger than 256mm in diameter (Mitchell, 2016). In order for a rock to be classified as conglomerate, all the fragments known as clasts need to be larger than 2mm in diameter (Pier, 2016).

3.2 Rock strength

In order to determine rock strength in different formations, the parameter unconfined compressive strength (UCS) was introduced. This parameter represents the maximum stress that a rock can take before it experience some kind of deformation. A number of different geomechanical problems can be addressed knowing this parameter, for instance wellbore instabilities during drilling and assessing sanding potential (Chang et al., 2006). When a rock is deformed, the ability to carry loads is reduced. If rock failures take place in the wellbore it can cause instabilities in the hole and production of solids. Because of this, it can be of great importance for drilling optimization purposes to predict when a rock is likely to fail (Fjær et al., 2008). In the following are different approaches to predict the rock strength.

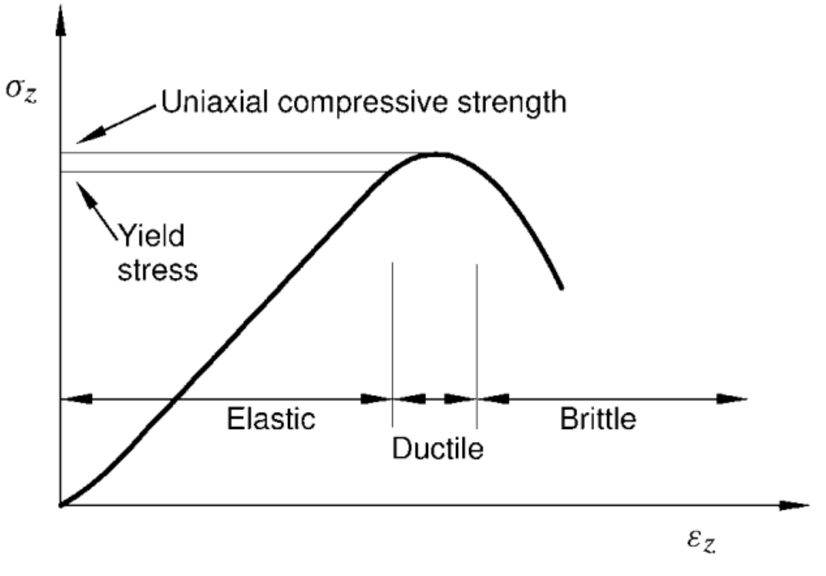

Figure 3.1: Stress versus deformation in a uniaxial compression test (Fjær et al., 2008)

Figure 3.1 depicts the results from a typical uniaxial test on a core sample where the deformation from increasing stress was reported. In the figure are σ_z and ε_z representing axial stress and strain respectively. The figure highlights several important concepts (Fjær et al., 2008)

- **Elastic region:** In this region, the rock is deforming elastically, meaning that when the applied stress is released, the rock will return to the original state
- **Ductile region:** In this region, the rock will experience permanent deformation, but it will not lose the ability to carry load
- **Brittle region:** In this final region, the ability of the rock to withstand stress decreases when deformation is increasing
- **Yield point:** The point where the rock will no longer return to the original state, permanent deformation has occurred

In order to be able to perform this uniaxial compression test, core samples need to be available from the formation to be tested. In practice, many geomechanical problems need to be addressed before core samples are available; therefor several empirical equations for different rock types have been developed to cope with this challenge. Only the equations for sandstone are discussed in this section, but there are similar equations for limestone and shale.

These empirical equations relate the rock strength to petrophysical parameters from well logs. The basic theory behind these relations is the fact that it is believed that the same factors affect the petrophysical parameters and the rock strength. The velocity, elastic moduli and the porosity are examples of such factors. Nearly all of the proposed relations for sandstone include one or a combination of these factors. A selection of the published relations for sandstone are given in Table 3.1 (Chang et al., 2006).

UCS [MPa]	Region developed	Comments
$0.035 \cdot V_p - 31.5$	Thuringia, Germany	-
$1.745 \cdot 10^{-9} \cdot \rho \cdot V_p^2 - 21$	Cook Inlet, Alaska	Coarse grained sandstone and conglomerates
$2.28 + 4.1089 \cdot E$	Worldwide	-
$254 \cdot (1 - 2.7 \cdot \phi)^2$	Sedimentary basins	Very clean, well-consolidated sandstone with $\phi < 0.3$

Table 3.1: Empirical relations between UCS and petrophysical factors (Chang et al., 2006)

In Table 3.1, V_p is the p-wave velocity that is directly measured, E is Young's modulus derived from measurements of velocity and density and φ represents the porosity derived from density measurements. When plotting the UCS against the different petrophysical factors, it can be concluded that the strength decreases for increased values of Δt ($\Delta t = V_p^{-1}$) and φ and that it increases for increased values of Young's modulus (Chang et al., 2006). These plots show very scattered results, meaning that no single empirical relation can fit all the data alone.

3.3 Effects of hard formation

Drilling through hard formations or formations with frequently changing hardness, causes several negative effects on the drilling process. The generation of unexpected doglegs and keyseats are some of the unwanted effects of running into hard formations during drilling. In addition to these effects, are effects related to equipment wear and eventually equipment failure. All of the negative effects mentioned in this section will result in reduced drilling efficiency and thereby increased drilling costs (Solberg, 2012).

3.3.1 Downhole problems

- **Unexpected dogleg**
  The term dogleg is used to describe the change in the well trajectory and can intentionally be made by the driller. Sometimes when drilling into harder formations, doglegs can be created unplanned and/or get larger than planned. The effects of an uncontrolled or unplanned dogleg generation can be many. It results in a deviation from the planned wellbore trajectory, which can cause difficulties both for the drilling process and when running the casing. A non-smooth well path can also lead to extensive casing wear due to increased contact forces between the drill pipe and the casing. This again have influence on the life span of the entire well, drill pipe and other downhole equipment, which can influence the well integrity. All the side effects from a non-

smooth well path caused by high or unplanned doglegs can cause significantly increased well costs (Schlumberger, 2016a).

- **Keyseats**
  Due to increased contact between the drill string and the wellbore, key seats can be created. Keyseats can also be caused when a ledge of hard formation is left between soft formations that enlarges over time. Keyseats are created when the drill string is rotating at the side of the borehole, causing a channel to be created. This causes problems when pulling out of hole with equipment of bigger diameter further down the string, like stabilizers and the drill bit. Due to this, keyseats can potentially cause stuck pipe (Schlumberger, 2016b). The concept of keyseats with increasing dogleg is illustrated in Figure 3.2.

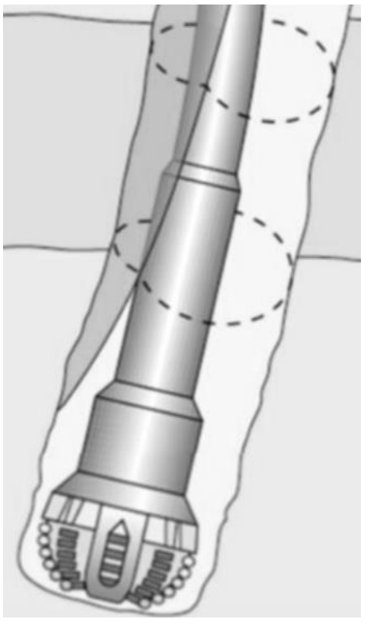

Figure 3.2: Illustration of keyseats with increasing dogleg (Lidal, 2016)

3.3.2 Equipment failure

In order to prevent wear on the downhole drilling equipment, good knowledge of the downhole environment is necessary. Using equipment not optimal for the environment or in a non-optimal placement in the drill string can increase the possibility of equipment failure. Knowledge of the conditions downhole should be utilized in the downhole drilling equipment selection process. For instance, an optimal bit for the section to be drilled is vital in order to achieve the desired rate of penetration through the formation. When entering formations with increased resistance to penetration, for instance hard formations, a normal action is to increase the weight on bit in order to achieve the wanted ROP. This action may increase drill string vibrations and shocks that could cause higher equipment wear and total equipment failure. If the downhole equipment is totally worn out or fails this may lead to an extra bit run, which will increase the drilling time and drilling costs (Solberg, 2012).

3.4 Drill bits

When optimizing the drilling process many factors need to be considered. Some of them are drilling fluid types and treatment, pump operations and the drill bit selection. In the optimization process, the conventional cost equation is a tool that can be used to calculate the cost per unit depth drilled

$$C_f = \frac{(t_r + t_t + t_c) \cdot C_r + t_r \cdot C_m + C_b}{\Delta D} \tag{3.1}$$

Where $t_r + t_t + t_c$ represent the bit rotation time, the total trip time and pipe connection time respectively and is given in [hours]. C_r is the fixed operation cost of the rig and C_m is downhole motor cost, both given as [$/ft]. C_b represents the cost of bit given in [$] and ΔD is the depth drilled in [ft] (Rastegar et al., 2008).

A good bit selection process will result in less non-productive time such as tripping due to longer bit life and it will contribute to a safer and more stable drilling process. According to equation (3.1) will this lead to lower drilling costs. Therefore, the bit selection process is very important when optimizing a well. The formations to be drilled are the most important factor in the process of choosing the right drill bit (Husvæg, 2015).

Below it is explained briefly some of the bit types that are currently used in the industry. In rotary drilling today, there are two main classifications of drill bits, roller-cone bits and fixed cutter bits where PDC-bits are the most common, both shown in Figure 3.3. This section covers both of the classifications, although the reservoir section in both Well A and Well B is drilled with PDC- bits.

Figure 3.3: PDC drill bit and an insert roller-cone drill bit (All-Biz, 2016, Varel, 2004)

3.4.1 Polycrystalline diamond compact bits- PDC

On the Norwegian Continental Shelf this type of bits are usually used in the dimension 17 ½" and smaller. Most of the PDC bits on the market today have no moving parts. Cutters made out of poly crystalline diamond are attached to the fixed surface of the bit. Cutters are placed in a specific design, which forms an outer and an inner structure. These structures are referred to when identifying and classifying the bit wear. This bit wear classification system is explained further in Section 3.6 and in Appendix A.

In order to achieve penetration in the rock, the poly crystalline diamond bits (PDC) are making the rock fail mainly due to shear stress instead of compressive stress as with the roller-cone bits given in section 3.4.2. The formation tends to fail with lower shear stress than with compressive stress, meaning that the PDC bits require lower WOB than the roller-cone bits to achieve the same ROP (Brechan, 2015).

Different formations are classified based on compressive strength and ROP as shown in Table 3.2.

Rock hardness	Compressive strength [psi]	ROP [ft/hr]
Very Soft	< 4000	> 70
Soft	4000 – 8000	35 – 70
Medium	8000 – 16000	15 – 35
Hard	16000 – 32000	15 – 5
Very hard	> 32000	< 5

Table 3.2: Rock classifications based on compressive strength and ROP (Brechan, 2015)

The PDC bits are usually utilized when the formation is in the range from soft and all the way up to the lower part of hard formations. The main reasons for using this bit is that it usually contributes to high ROP and long bit life, as long as it is utilized in a suitable formation. For the PDC-bit, the rate of penetration depends on effective WOB and the removal of cuttings, which is dependent on rotation and hydraulics. As the cutters wear down during drilling, higher WOB is often needed to achieve the same depth of cut (Brechan, 2015).

The design of the PDC bit is determined in order to optimize the drilling process concerning high rate of penetration and low bit wear. The final design is based on the following considerations (Husvæg, 2015).

- Materials
- Formations properties
- Mechanical parameters
- Hydraulic conditions

In order to customize the bit to these conditions, three different blade profiles for the bit design are developed; long parabolic profile, medium parabolic profile and a flat profile. In ideal conditions with no issues like directional wells, non-homogeneous formations, special BHA setup, etc., one can say that; a long parabolic blade profile is most suitable in soft and abrasive formations. A medium parabolic blade profile is the best choice for hard and medium abrasive formations, while a flat blade profile PDC bit is most suitable in hard and non-abrasive formations. The parabolic profile is usually experiencing larger bit wear than the flat profile due to the possibility of more aggressive drilling with higher ROP (PetroWiki, 2016a)The abovementioned PDC- bit profiles are given in Figure 3.4.

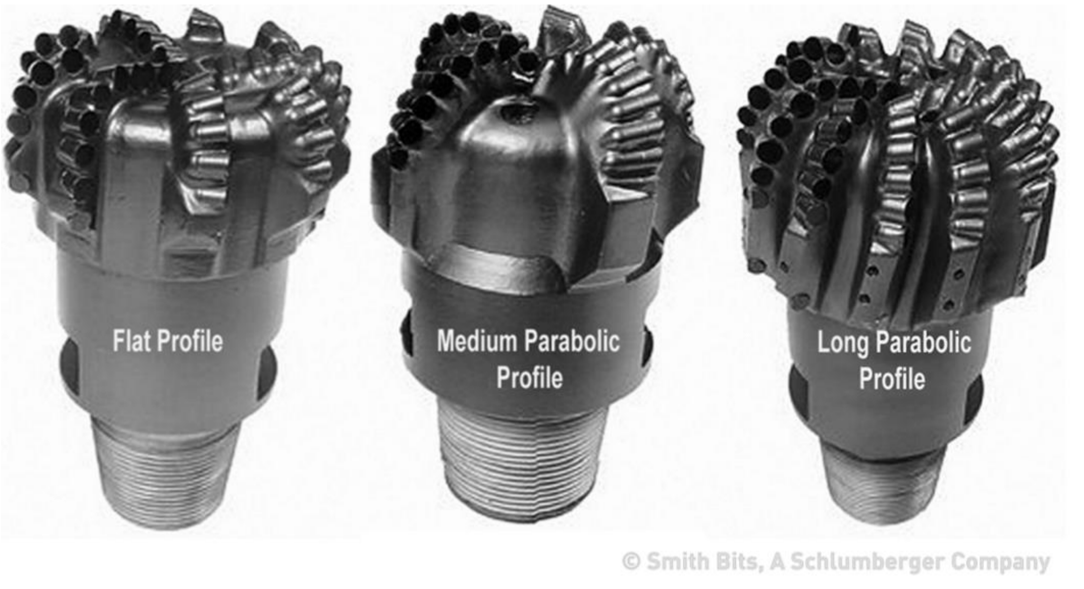

Figure 3.4: Different PDC-bit profiles (PetroWiki, 2012)

The profile design have great impact on different parameters such as bit stability, RPM, WOB and bit durability. This needs to be taken into account in the process of designing the drill bit (PetroWiki, 2016a).

3.4.2 Roller-cone bits

The other classification of bit mentioned in this section is the roller-cone bit. There are two main categories of roller-cone bits, called mill tooth and insert bits, both depicted in Figure 3.5. These bits consist of usually three rolling cones with cutting elements attached that can rotate about their axis. Tungsten carbide inserts that are placed in pre-drilled holes in the steel cone are the foundation of the insert bits, while the milled tooth bit is made by milling the teeth out of the cone (Bourgoyne et al., 1986).

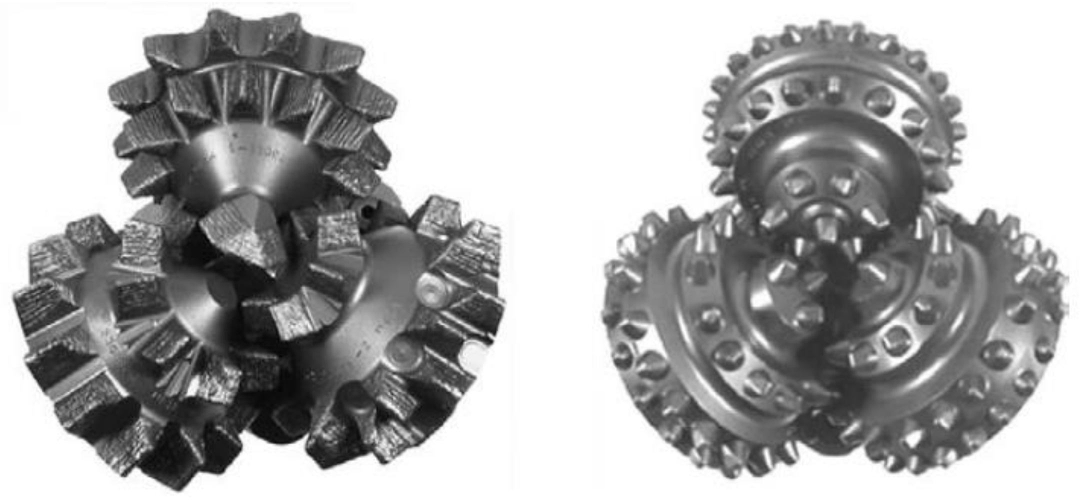

Figure 3.5: Milled tooth bit (left) and insert bit (right) (Brechan, 2015)

When designing a roller-cone bit there are several key design elements that need to be determined based on knowledge about the formation being drilled and the directional work being done. Some of the design elements to be determined are given below (Brechan, 2015).

- Mill tooth or insert bit
- Cone offset/skew angle and journal angle
- Tooth design
- Reinforcement in case of abrasive formations
- Energy balance

The journal angle is usually the first design element to be determined and it is defined as the angle between the axis of the bit's leg journal and a line perpendicular to the bit axis, as depicted in Figure 3.6. In soft formations a low journal angle (~33°) is the most suitable, while higher angle (~36°) is utilized in harder formations (PetroWiki, 2016b).

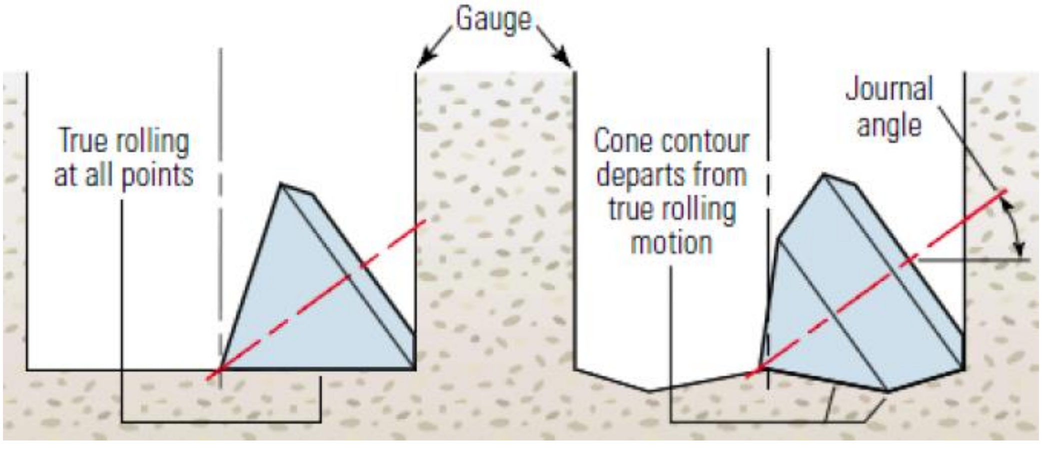

Figure 3.6: The principal of journal angle (Brechan, 2015)

The next important design feature of the roller-cone bits is the cone offset angle or skew angle shown in Figure 3.7. In cases of no cone offset, their axis intersects at a common point along the centerline of the borehole. If the cones have an offset angle, the rotational movement will periodically stop as the bit is turning and scraping the bottom of the hole. The drilling speed is usually increased due to this mechanism, but it also leads to more aggressive tooth wear (Bourgoyne et al., 1986). This mechanism is also a crucial part in order to get the cutting removed in the drilling process (Brechan, 2015).

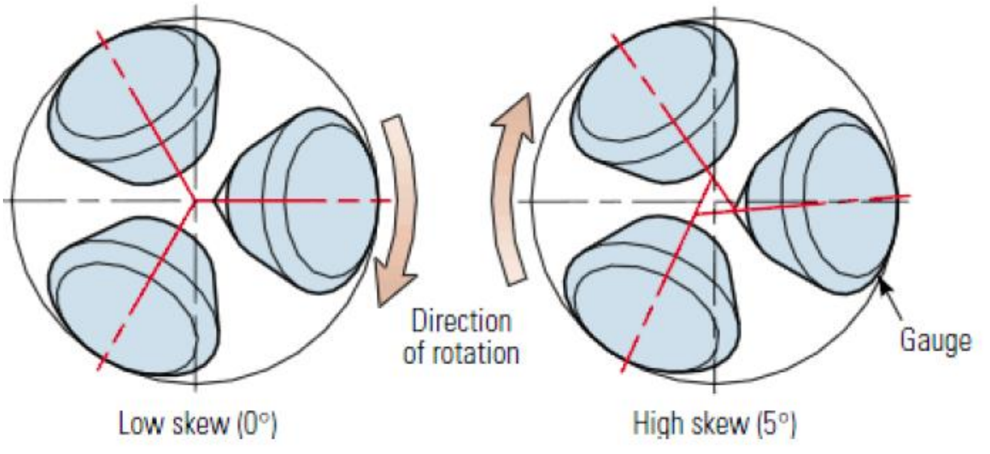

Figure 3.7: Cone offset or skew angle of cones (Brechan, 2015)

In soft formations a cone offset of approximately 4° is utilized and the offset reaches 0° in extremely hard formations (Bourgoyne et al., 1986).

The two types of roller-cone bits both achieve formation removal and ROP by the use of compressional failure of the rock, but different mechanisms take place in the process. In cases of no offset angle, the formation is exposed to crushing mechanisms by the cones. When the offset angle is increasing, the cutting mechanisms are more like gouging and scraping. The difference in these mechanisms is shown in Figure 3.8. In order to design the bit in the best way for the formation being drilled, both the journal angle and the cone offset needs to be optimized (Brechan, 2015).

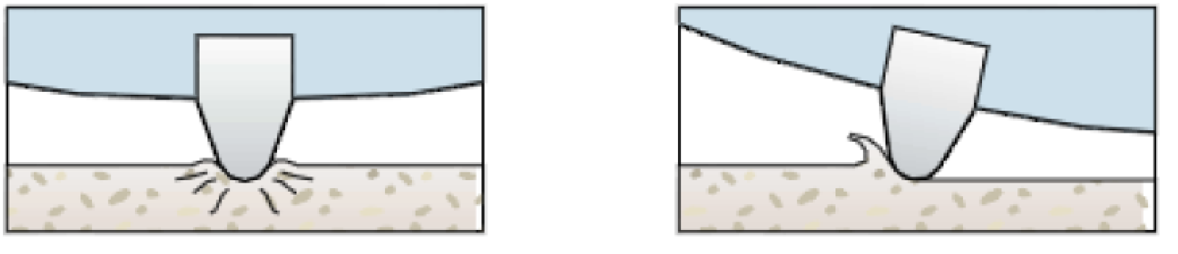

Figure 3.8: The mechanism of crushing (left) and scraping (right) (Brechan, 2015)

The tooth design for both the milled tooth bit and the insert bit is dependent on the formation being drilled. In soft formations, the trend is fewer and longer teeth for both bits, while in hard formations there are more and shorter teeth that are utilized for both of the bit types.

3.5 Wear to PDC-cutters in conglomerate

The PDC- bits are dependent on the cutters, in order to achieve the desired rate of penetration. Wear to the cutters is affected by many factors and several studies have tried to investigate how to design the cutters in order to withstand the damage. Impact damage, heat damage and abrasive wear are all issues that will affect the performance of the PDC-bit.

As stated previously, conglomerate consists of clasts with a wide variety of sizes and hardness. This have historically made several problems related to the drilling process, most important severe wear to the drill bit. There are different mechanisms likely to cause wear to the cutters when drilling conglomerate, including axial vibrations causing bit bounce and stick-slip due to hard boulders (Schlumberger, 2010). When drilling into a hard clast, the cutters can be fatally damaged within just a few meters causing the rate of penetration to decrease drastically, which require pulling of the bit.

To optimize the drilling process when drilling challenging formations, it is of great interest to improve the drill bit and the cutters. Lundin Norway AS in cooperation with various bit vendors have tested and developed an experimental bit with cutters that are capable of withstanding the damage from drilling conglomerate (Hellvik et al., 2012). Therefore, in this study it is assumed that the drill bit is worn gradually when drilling consecutive intervals of conglomerate.

3.6 Bit grading for PDC bits

After a bit run, the bit wear is investigated and classified with the use of a dull bit grading system developed by International Association of Drilling Contractors, IADC. There are different classifications for PDC-bits and for roller-cone bits. Since the reservoir sections in both Well A and B are drilled with PDC-bits, only the dull grading system for these bits are explained further.

This system describes the following characteristics with the PDC-bit used

1. Wear on the inner cutting structure
2. Wear on the outer cutting structure
3. Dull characteristics
4. Location
5. Bearing/Seals
6. In/out of gauge
7. Other dull characteristics
8. Reasons pulled

All bits get a dull bit grading consisting of eight numbers and letters, one for each of the characteristics above. For the PDC-bits, the inner cutter structure represents 2/3 of the radius, while the remaining 1/3 is referred to as the outer structure, as depicted in Figure 3.9. The wear on the two cutting structures are given numbers between 0-8 to describe the severity of lost, worn and broken cutting elements. If the value exceed 5, the cutters are severely damaged. The characterization of the wear to the cutting structure is very important since the PDC bits are dependent on the cutters in order to achieve progression in the drilling process.

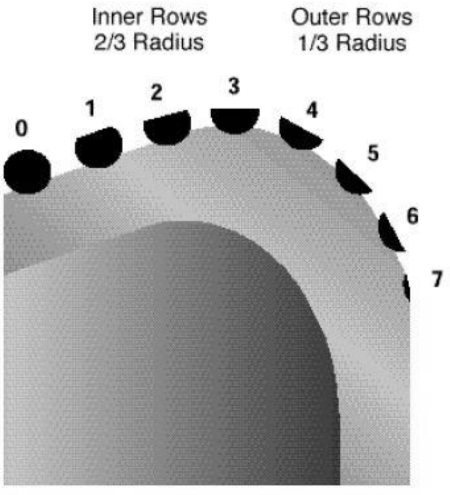

Figure 3.9: Inner and outer structure of PDC-bit (Brechan, 2015)

The next two characteristics represent what have happened to the cutter elements and nozzles. It is stated whether these elements are chipped, broken or lost. In addition, the location of these damaged elements are given and the different parts of the bit structure are given in Figure 3.10.

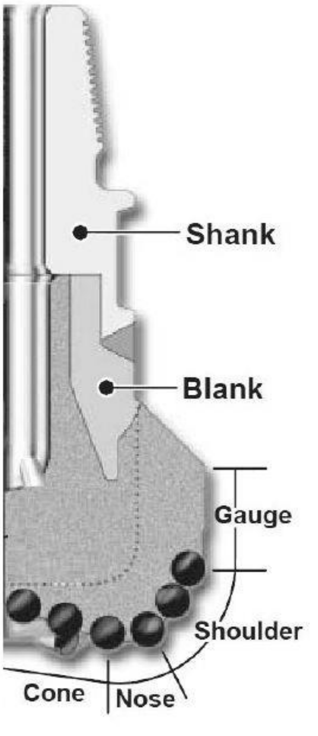

Figure 3.10: Location on the bit structure (Brechan, 2015)

All the locations are named with different letters that are a part of the total bit dull grading. The next part of the dull grading is describing whether the bit is out of gauge or not when the bit is pulled. The last characteristic about the bit given in the bit grading refers to why the bit was pulled (Halliburton, 2009). All the numbers and letters to describe the bit wear are explained more in details in Appendix A. The dull bit grading for the bits used in the two wells evaluated in this thesis is given in Section 7.3.

4 Access to downhole data

In the drilling industry today the need for a more accurate and detailed understanding of the downhole environment is crucial since the target zones are more complex and the drilling costs are so high. The next section will discuss one kind of tool that measure downhole mechanical data, CoPilot tool provided by Baker Hughes. With the information from such tool, the drilling process can be optimized and executed more efficiently.

4.1 CoPilot

CoPilot is a multiple-sensor downhole tool by Baker Hughes that provides the driller with real-time downhole drilling data, both mechanical measurements and detection of problems related to the dynamics. The intention of running this tool is to get a better understanding of the downhole environment and to be able to prevent vibrations that can occur during drilling. The multiple sensors measure the downhole condition and transfer the signal using mud pulse telemetry all the way to a display where the driller can monitor the drilling process. The CoPilot sub can be placed anywhere suited in the BHA design. The location in the BHA depends on the logging requirements and the drilling application (BakerHughes, 2011a).

4.1.1 Basic design

The CoPilot tool consists of three main parts as depicted in Figure 4.1. The lowermost part of the tool, the electronic sub (1), contain all the sensors for mechanical and dynamic measurements. As protection, a sleeve (2) which is press-fitted by the top tub (3) covers these sensors.

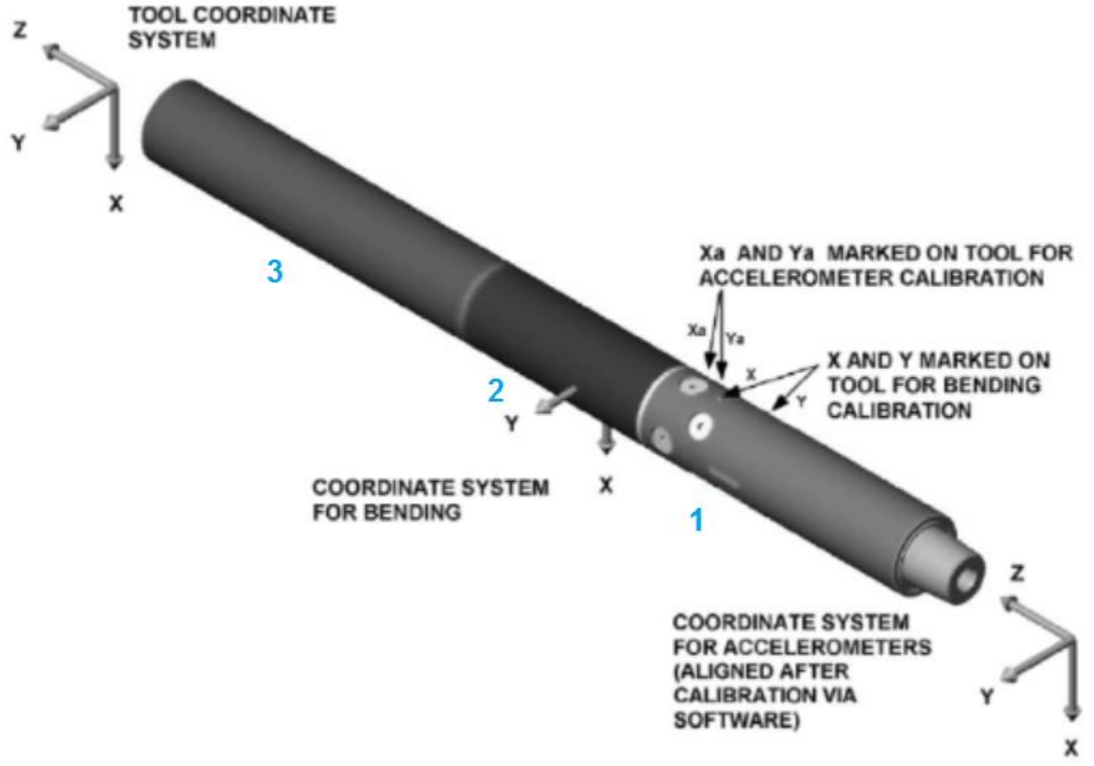

Figure 4.1: Main components of the CoPilot sub (Vikra, 2008)

To be able to calculate the exact downhole parameters, the CoPilot tool is using a coordinate system containing an x, y, and z-axis. As depicted in Figure 4.1, the z-axis is pointing upwards along the drill pipe, while both x and y-axis are pointing in the radial direction. The direction of the arrows represent positive values for both bending of the tool and acceleration in all directions, so if the motion is in the opposite direction, the value will come back negative (Vikra, 2008).

4.1.2 Output data

With the use of this tool in the BHA, a variety of different real-time downhole parameters are available. The 14 different sensors in the electronic sub are sampled simultaneously at 1000Hz and their input variables are for instance

- Weight on bit
- Torque
- BHA bending moment
- Accelerations
- Magnetometer signals
- Temperature
- ECD

After processing these input data in the digital signal processor, the data are converted into information classified as static measurements and dynamic diagnostics given in Table 4.1.

Category	Static Measurements	Dynamic diagnostics
Axial	WOB	Bit bounce
	Axial acceleration	Axial vibration severity
Lateral	Bending moment	
	Bending rate	
	Lateral acceleration	
Torsional	Torque	Stick-slip
	Downhole string rotation rate	Tangential vibration severity
	Tangential acceleration	
	Motor RPM	
Hydraulics	Annulus pressure (ECD)	
	Differential pressure	
	Annulus temperature	

Table 4.1: Co-pilot key data and diagnostics (BakerHughes, 2011b)

The main benefits from using CoPilot are that it serves as a tool in the process of optimization the drilling parameters. It provides improved directional control and may help in openhole sidetracking when needed. Drilling related problems such as whirl can be detected at an earlier stage, resulting in a risk reduction. When drilling in interbedded formations and other complex structures, the CoPilot helps so that the drilling efficiency is maintained and could reduce the non-productive time (BakerHughes, 2011b).

5 Drilling optimization

There are different methods available today to optimize drilling parameters in order to obtain the maximum rate of penetration in each bit run. The rate of penetration is affected by many different factors and some of them are explained in details in this chapter. A selection of mathematical models that investigate how these factors affect the rate of penetration is also discussed in this chapter.

The concept of drillability and a selection of studies on the topic are included since this parameter gives an indication of the formation hardness and it is decisive for the bit wear experienced during the drilling process. Drillability and formation hardness are closely related to the rate of penetration.

5.1 Factors affecting the rate of penetration

There are several factors affecting the drilling process, and multiple authors have investigated this topic during the evolution of the drilling industry. Common for the studies is that the factors are divided into two main categories. One group of variables are controllable from surface and can be adjusted to achieve optimized drilling, while the other category is variables that are a result of the controllable variables and that are dependent on the downhole environment. Some of the most important variables in the two categories are given in Table 5.1.

Controllable Factors	Environmental Factors
Weight on bit	Formation type
Rotational speed	Formation properties
Hydraulics	Mud type
Bit design	Bit size
Bit wear state	

Table 5.1: Independent and dependent factors affecting the ROP (Fear, 1999)

Mud type parameters such as type and density are categorized as environmental factors due the fact that they are dependent on formation type and pressure (Fear, 1999). As can be seen from Table 5.1, there are many factors affecting the rate of penetration and the relationships are complex. The next sections will go into the most important factors from Table 5.1.

5.1.1 Controllable variables

The controllable variables are determined to optimize the drilling process and they can be adjusted at surface in order to achieve that. The first controllable variable to be discussed is the operation conditions, such as the weight on bit and the rotary speed.

Weight on bit is crucial in order to achieve progress during drilling. For progress to be possible, the applied weight on the bit needs to exceed the strength of the formation drilled. Therefore, the needed weight on bit depends on the rock strength and the size and geometry of the bit used in the drilling operation (Fasheloum, 1997).

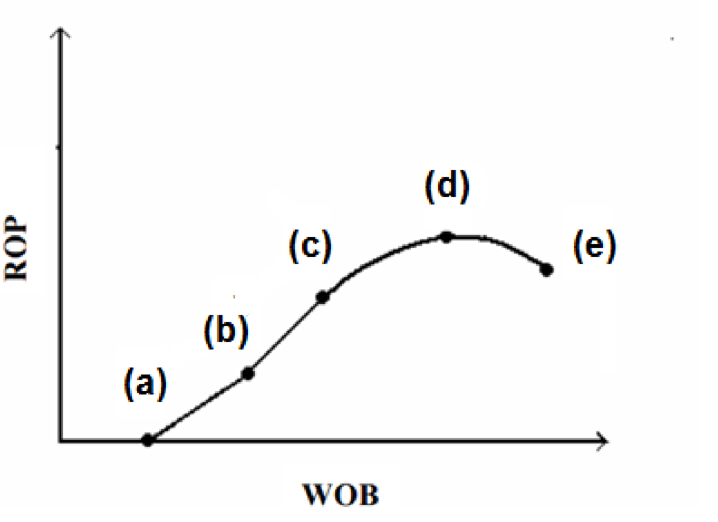

Figure 5.1: The resulting ROP with increasing WOB (Bourgoyne et al., 1986)

Figure 5.1 depicts the typical behavior of the rate of penetration when the applied weight on bit is increasing and all other variables are kept constant. As stated, the WOB needs to exceed a certain level to obtain any ROP, shown in point (a). When the WOB is increasing from (a) to (c), the resulting ROP is also increasing rapidly. From (c) to (d) it can be seen that an increase in WOB only causes a moderate increase in the ROP. At very high WOB, there are even a decrease in the resulting ROP, shown from point (d) to (e). This response is a result of bit floundering. This type of relation between the rate of penetration and the weight on bit is due to less efficient bottomhole cleaning at higher rates of cuttings generation. At this high values of WOB, the bit wear are significant (Bourgoyne et al., 1986).

In addition to the weight on bit, the rational speed have great impact on the rate of penetration. As for the weight on bit, several studies have been performed in order to investigate the relationship between the rotational speed and the penetration rate. Figure 5.2 shows the resulting ROP with increasing RPM when all other variables are kept constant.

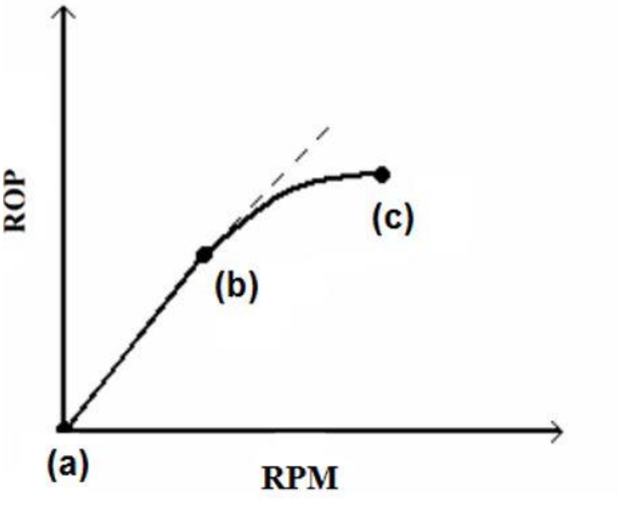

Figure 5.2: The resulting ROP with increasing RPM (Bourgoyne et al., 1986)

As depicted in Figure 5.2, the resulting ROP have a linearly increasing trend with increasing RPM from (a) to (b). At higher values of RPM, this linear relation is no longer present. This is related to a less efficient cleaning of the bottom of the hole.

Another factor that will severely influence the rate of penetration is the bit tooth wear experienced during drilling. Both the roller-cone and the PDC bits are dependent on the teeth and cutters on order to achieve progress in the formation. Due to this, bit wear result in a reduction in the rate of penetration. Bit wear covers reduction in teeth length, broken, damaged and/or lost teeth and cutters.

In order to achieve an optimum rate of penetration, the selection of the drill bit is very important. In the drilling industry today there are several different types of drill bits available, some of them are discussed in section 3.4. They are all designed to cope with different formations and rock strength. For roller-cone bits are generally the maximum ROP achieved using long teeth and a large cone offset as mentioned in section 3.4.2. Roller-cone bits with these features can only be utilized in soft formations, due to the rapid destruction in hard formations. Therefore, the roller-cone bits that will result in the highest ROP are the bit with the longest tooth that will give a tooth life consistent with the bearing life given that the bit is operating at optimum conditions. For the PDC bits on the other hand, the size and number of cutters need to be determined in order to achieve the optimum ROP (Bourgoyne et al., 1986).

In the process of selection the right bit for the drilling operation, a combination of methods are utilized (Fasheloum, 1997).

- Cost analysis
- Offset well bit record analysis
- Geophysical and geological data analysis

5.1.2 Environmental variables

This section will discuss the dependent variables that are given by the downhole environment and that are a result of the controllable variables from section 5.1.1.

There are many different characteristics about the formation that will affect the ROP during drilling. The most important feature is the elastic limit and the ultimate formation strength. In order to determine the formation strength, different methods can be used. Some of the methods are discussed in Section 3.2.

In addition to the formation strength, rate of penetration is influenced by the permeability of the formation. Drilling fluid filtrate can invade the rock ahead of the bit to equalize the pressure differential if the rock is permeable. The mineral composition can also affect the obtained rate of penetration. If the formation consists of hard and abrasive minerals, the bit will experience substantial wear, which will result in a reduced rate of penetration (Bourgoyne et al., 1986).

As mention above, the mud type is included as an environmental variable. The properties of the drilling mud that affect the rate of penetration are density, rheological flow, filtration characteristics, solid content and the chemical composition. The differential pressure across the zone of crushed rock under the bit is controlled by the fluid density, solid content and filtration characteristics, while the hydraulic energy that is available for hole cleaning is controlled by the fluid viscosity. In general, an increased filtration rate will result in an increased ROP, while an increased fluid density, solid content and viscosity will give a reduced ROP (Bourgoyne et al., 1986).

One of the most important variables affecting the cost per unit depth drilled given in equation (3.1) is the rate of penetration. An optimized rate of penetration through the formation will result in improved efficiency and reduced costs (Fasheloum, 1997). Since the rate of penetration is the major parameter determining drilling efficiency and optimization, Section 5.3 presents mathematical models to investigate how the rate of penetration is affected by the factors discussed in this section.

5.2 The concept of drillability

The drillability of a formation is decisive for the bit wear experienced during the drilling process. In order to reduce the drilling costs it is of great importance to be able to predict the drillability based on the predicted rock conditions (Thuro, 1997). Drillability is a parameter that has been defined differently by various people during the evolution of the drilling industry. The investigation of this parameter is an ongoing process to be able to come up with the best way to describe this relation between the bit and the formation being penetrated.

Since this parameter has been evaluated a lot during the history and it is important to understand how it is related to bit wear and rock properties, this section is dedicated to describe briefly some of the studies performed. The studies mentioned in this section are

- A. L. Head, 1951
- W. H. Somerton, 1959
- Gstalder and Raynal, 1966
- Somerton, Esfandiari and Singhal, 1969
- Overton, 1973
- Yin, 1986
- Prasad, 2009

In 1951, Head performed limited tests to determine whether he could prove a relationship between drillability and the hardness of the rock being drilled. He tested and classified fifteen hard formations according to how efficient they could be drilled and how resistant they were to penetration as given in Table 5.2.

Formation	Drillability classification number	Knoop hardness
Sandstone, Wilcox	1.9	813
Lime, Canyon Reef	2.0	630
Anhydrite	3.4	127
Hard marine shale, Hosston	4.3	176
Sandstone	37.3	988
Chert	45.8	745
Quartzitic sandstone, Hosston	555.7	1118

Table 5.2: Comparison of the drillability and hardness (Head, 1951)

Based on the results given in Table 5.2, Head concluded that there were no relationship between the drillability and the hardness of the formation drilled. Instead, he concluded that drillability was more related to how hard the crystals in the formation were bound together. This classification has been proven to be in consistency with the actual drilling practice. Head used this system to classify which type of drill bits that performed most efficient in the different formations, by comparing the rate of penetration for the different bits. This made the foundation for an efficient bit selection for a particular formation (Head, 1951).

In 1959, Somerton performed laboratory tests to investigate rock breakage during rotary drilling. He wanted to investigate the effects of drilling variables on the drilling rate and the efficiency of the drilling process. Somerton used samples of specially prepared concrete, sandstone and shale in the tests performed. The intention of the laboratory tests was to investigate how the drilling rate was effected by rock strength and bit wear and to see whether a model could express this relation.

The character of the breakage were determined by analyzing the cuttings from the drilling process. The variables controlling the bit penetration rate were given as follows

$$ROP = C \cdot d_{bit} \cdot RPM \cdot \left(\frac{WOB}{d_{bit}^2 \cdot S}\right)^a \tag{5.1}$$

Here the diameter of the bit used is d_{bit} [inch], RPM [rpm] is the rate of rotation, WOB [lb] is the effective weight on bit, S [psi] represents the rock strength, while both C and a are constants to be determined experimentally.

The only parameter from equation (5.1) that is difficult to determine is the rock strength parameter. Somerton compared drilling strength for different rock types and through the tests it was concluded that ultimate compressive strength is not an adequate measure of rock drillability. Somerton concluded that this was due to the complex nature of rock breakage during rotary drilling and that different rocks have different strength characteristics (Somerton, 1959).

Gstalder and Raynal performed in 1966 simple tests to measure rock drillability. In order to investigate the drillability, rock breakage was considered. First, the formation hardness was determined through a test procedure that involved increasing the load until the rock sample experienced rupture. This hardness data was used in order to compare effectiveness of different breakage methods in the rock. From the tests performed, it was concluded that hardness is a good measure of the breaking strength of the rock. The test also showed that it is a useful relationship between rock hardness and sonic velocity that can be used to determine rock drillability, given that mineralogical characteristics are taken into account (Gstalder and Raynal, 1966).

In 1969, Gstalder and Raynal's study was revisited and extended by Somerton, Esfandiari and Singhal, in order to find better ways of measuring rock drillability. Somerton, Esfandiari and Singhal, defined drillability as a measure of the volume of drilled rock for each unit of energy put into the process. This new study confirmed the conclusion made by Gstalder and Raynal that sonic velocity is connected to the rock drillability. In order to obtain good correlations, a distinction between limestone and sandstone had to be established. After laboratory drilling tests were performed, the drillability was defined as

$$Drillability = \frac{ROP \cdot A}{T \cdot RPM} \tag{5.2}$$

Here is the ROP presenting the drilling rate, A is the cross-sectional area of the borehole, T represents the torque on the bit and the RPM [radians/unit time] is a measure of the rate of rotational speed. The value of drillability does vary with drill bit type and there are best correlations if the weight on bit is in a medium range (Somerton et al., 1969).

In 1973, Overton performed an analysis to come up with a generalized drillability equation. The interaction of the rotating drill bit, rock properties and the circulation system were some of the interactions he investigated in order to come up with such an equation. In comparison to Somerton, Esfandiari and Singhal, Overton defined drillability to be the rate that a given formation was penetrated. By using dimensional analysis and boundary conditions, Overton came up with a generalized drillability equation. In order to solve this equation, several variables have to be determined

- 10 measurable variables
- 2 coefficients dependent upon rotary bit and mud practice
- 2 parameters dependent upon rock composition

The last four parameters need to be determined through experiments, while the other ten variables are easily measured and they include the rotary speed, weight on bit, hole diameter, drilling depth and tooth height (Overton, 1973).

In 1986, Yin introduced a new experimental and statistical method for drillability calculations that resulted in a quantitative correlation between various parameters. Unlike all the other models given above does the experiment performed by Yin introduce the possibility of a heterogeneous formation. The quantitative information of drillability can be used in order to find a representative evaluation of the formation drilled. (Yin, 1986) put up an equation to calculate formation grade of drillability varying with depth. This empirical equation represents the characteristic of individual heterogeneous formations. The equal probability correlation between this calculated formation grade, bit type and calculated drilling rate, was utilized to put up a basis for the process of selecting bits and monitoring the formation drillability during drilling (Yin, 1986).

The final study on drillability mentioned in this section is performed by (Prasad, 2009). He defined drillability in terms of the following eight simple properties

- Rock density
- Rock porosity
- Compressional wave velocity, P
- Shear wave velocity, S
- Unconfined compressional strength, UCS
- Mohr friction angle
- Rock mineralogy, Q (only quartz minerals)
- Grain size

These properties are determined either from core samples from the borehole or from logging while drilling. In order to characterize drillability in terms of the different rock properties in this list above, Prasad normalized the values on a scale from 0-8 and plotted them in a spider-plot as depicted in Figure 5.3.

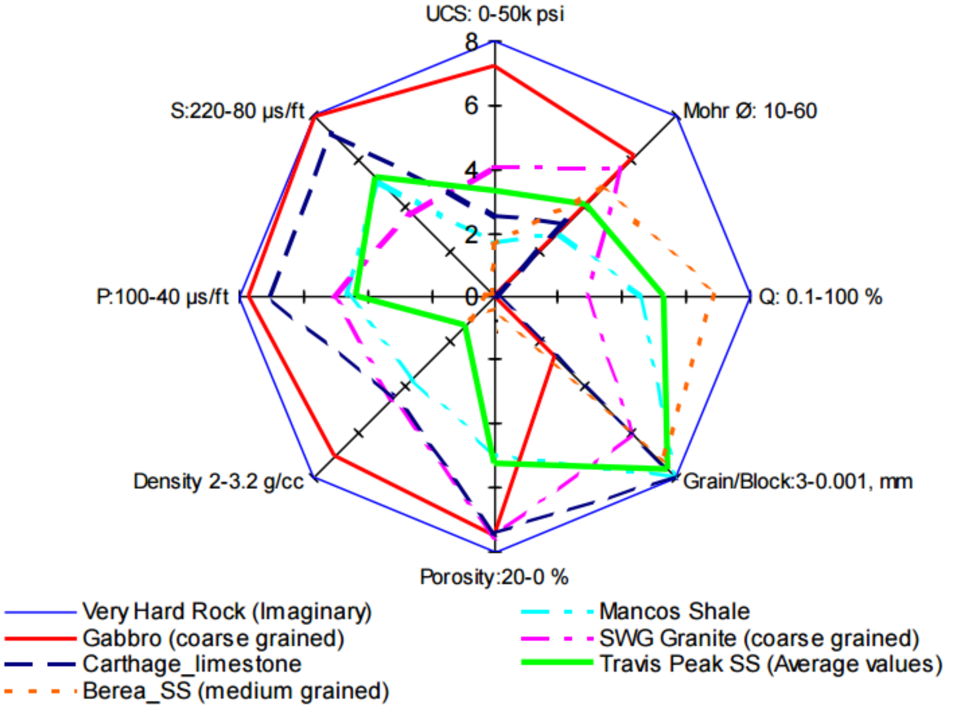

Figure 5.3: Plot of drillability in terms of different rock properties (Prasad, 2009)

In this spider-plot, the value 1 represent very soft rocks, while the value 8 indicate hard rocks. The real rock is in between depending upon the rock type. Low values of porosity, acoustic slowness and grain size indicate harder rocks. The axis for these variables are reversed in Figure 5.3, so that the values closer to the center still represent softer rocks. The results depicted in Figure 5.3 laid the foundation for an optimized bit selection and drilling process (Prasad, 2009).

The seven different studies mentioned above are only a limited selection of all the studies regarding the concept of drillability. Many of the studies utilized the rate of penetration to estimate a value for the drillability. In order to estimate the maximum rate of penetration and to separate soft and hard formations, the next section is dedicated to look more into the coherence between drillability and the change in rate of penetration in the formation drilled.

5.3 Mathematical models

The rate of penetration is controlled by many complex factors as described in section 5.1. During the drilling history, several mathematical models have tried to combine these factors in order to estimate an optimized rate of penetration. However, due to the large quantity of parameters affecting the rate of penetration, no absolute accurate model have been developed yet (Bahari and Baradaran Seyed, 2007).

Several authors have stated the fact that in order to minimize the costs per foot for the formation drilled, it is important to get a good prediction of the penetration rate to be able to optimize drilling parameters (Bahari and Baradaran Seyed, 2007) (Hareland et al., 2010). In order to optimize the drilling process two main methods have been developed; rate of penetration calculations and mechanical specific energy (MSE) models.

These models can be used when selecting optimal weight on bit and rotary speed, in order to optimize the drilling efficiency and minimizing cost per foot for the formation drilled (Rashidi et al., 2008).

The ROP models can be used in order to calculate the formation drillability explained in section 5.2, determine bit design and detect bit wear (Rashidi et al., 2008). In comparison, can the use of MSE-models make it possible to enhance instantaneous rate of penetration by optimizing the drilling variables. This model provides a tool to monitor changes in the drilling efficiency during drilling.

The next sections will discuss some of the best models developed both in rate of penetration calculations and for MSE-determination, starting with the most complete mathematical drilling model so far (Bourgoyne et al., 1986).

5.3.1 Bourgoyne & Young

In 1974, Bourgoyne & Young came up with a mathematical equation as an attempt to combine the rate of penetration with a number of drilling variables and formation characteristics. They proposed a model that contained eight different variables and their effect on the rate of penetration, given in equation (5.3) (Bourgoyne and Young, 1974).

$$ROP = f_1 \cdot f_2 \cdot f_3 \cdot f_4 \cdot f_5 \cdot f_6 \cdot f_7 \cdot f_8 \tag{5.3}$$

The eight variables included in equation (5.3) are as follows

- **Formation strength, bit type, mud type, solid content**

$$f_1 = e^{2.303 \cdot a_1} = drillability \tag{5.4}$$

  The effect of formation strength is included in the constant a_1. This function includes all the effects that are not considered in the other functions, for instance the effect of drilled solids. This function is useful when applying a multiple regression technique, presented by Bourgoyne and Young in 1974. The equation f_1 is often referred to as the formation drillability, because it is expressed in the same terms as the penetration rate (Bourgoyne and Young, 1974).

- **Different types of compaction**

$$f_2 = e^{2.303 \cdot a_2 \cdot (10000 - D)} \tag{5.5}$$

$$f_3 = e^{2.303 \cdot a_3 \cdot D^{0.69} \cdot (g_p - 9.0)} \tag{5.6}$$

  Both of the equations model the effect of compaction. In these equations, D represents depth in [feet] and g_p represent the pore pressure in [lbm/gal]. The fact that rock strength increases due to normal compaction with depth is accounted for in f_2, while the function f_3 includes the effect of under-compaction in abnormally pressured formations (Bourgoyne et al., 1986). It is assumed that the rate of penetration has an exponential decrease with depth in formations that are normally compacted and an exponential increase with pore pressure gradient. Both of these assumptions are based on compaction theory, not experimental verifications.

The product of the two functions are equal to 1.0 in cases when the pore pressure gradient is 9.0lbm/gal and the depth is 10000ft (Bourgoyne and Young, 1974).

- **Overbalance**

$$f_4 = e^{2.303 \cdot a_4 \cdot D \cdot (g_p - \rho_c)} \tag{5.7}$$

As in equation (5.5)-(5.6), D and $g_p$represents depth and pore pressure respectively, while ρ_c is the mud weight used. This function includes the effect of differential pressure on the rate of penetration. In cases of excess bottomhole pressure, it is assumed that the penetration rate is decreasing exponentially. When the bottomhole pressure is equal to the formation pore pressure (zero overpressure), the function f_4 has a value of 1.0 (Bourgoyne and Young, 1974).

- **Weight on bit and rotary speed**

$$f_5 = \left[\frac{\left(\frac{WOB}{d_b}\right) - \left(\frac{WOB}{d_b}\right)_t}{4 - \left(\frac{WOB}{d_b}\right)_t} \right]^{a_5} \tag{5.8}$$

$$f_6 = \left(\frac{RPM}{60}\right)^{a_6} \tag{5.9}$$

In these equations is $d_b$representing the diameter of the bit, WOB is the applied weight on bit, $\left(\frac{WOB}{d_b}\right)_t$ is the threshold bit weight per inch of bit diameter and RPM represents the revolutions per minute. The two functions above is representing the effect of weight on bit and rotary speed on the rate of penetration respectively. From equation (5.8) and (5.9) it is assumed that the rate of penetration is directly proportional to $\left(\frac{WOB}{d_b}\right)^{a_5}$ and $(RPM)^{a_6}$. The functions are defined like this so that the product of the two will be equal to approximately 1.0 during common drilling conditions (Bourgoyne and Young, 1974).

- **Bit tooth wear**

$$f_7 = e^{-a_7 \cdot h} \tag{5.10}$$

The variable h represents the fractional bit tooth wear and the variable a_7 are dependent on the type of bit used to drill the formation, not so much on the formation type itself. In cases of an insert bit, there are no significant variations in the rate of penetration. The function f_7 has the value 1.0 if there are no bit tooth wear (Bourgoyne and Young, 1974).

- **Bit hydraulics**

$$f_8 = \left(\frac{F_j}{1000}\right)^{a_8} \tag{5.11}$$

This final equation models the effect of bit hydraulics on the penetration rate, with the jet impact force F_j as the hydraulic parameter of interest (Bourgoyne et al., 1986).

When combining the independent variables described in equation (5.4) - (5.11), the rate of penetration can be determined. In order to make use of these equations, the eight constants a_1-a_8 need to be determined based on local drilling conditions. Experience from previously drilled wells in the area lay the foundation for the determination process. The accuracy of this model is highly dependent on how these constants are determined (Bourgoyne et al., 1986).

5.3.2 Warren's imperfect-cleaning model

The next model for rate of penetration estimation presented in this section is the so-called perfect cleaning model developed by Warren in 1987. This model is based on the principal that the rate of cuttings transportation from the bit is equal to the rate at which new chips are produced during steady-state drilling conditions. The processes that control the rate of penetration are the cuttings accumulation and the cuttings removal, or a combination of both (Rastegar et al., 2008). This model relates the rate of penetration to the weight on bit, rotary speed, rock strength and bit size in the following way (Warren, 1987)

$$ROP = \left(\frac{a \cdot S^2 \cdot d_{bit}^3}{RPM^b \cdot WOB^2} + \frac{c}{RPM \cdot d_{bit}} \right)^{-1} \tag{5.12}$$

Where the constants a-c are dimensionless bit constants and d_{bit} [inch] is the diameter of the bit used. RPM [rev/min] is the rotational speed and WOB [lbf] represents the applied weight on bit.

The first term in equation (5.12) are based on this assumption that a fixed number of teeth, independent of the penetration depth, are supporting the weigh on bit applied.. It represents the maximum rate that new rock chips can be generated by the interaction between the bit and the new formation. By adding the second term, equation (5.12) also takes into account that when the teeth penetrate deeper into the rock, the weight on bit is applied to more teeth as it increases. For a given fixed rotational speed, this term also provide an upper limit to the rate of penetration (Warren, 1987).

The perfect-cleaning model described in equation (5.12) is not effective to predict rate of penetration in the field, since the rate of penetration is slowed down by an imperfect removal of cuttings from under the bit. In order for the model to be applicable for rate of penetration calculations in the field, it needed to be modified to account for the imperfect hole cleaning.

(Warren and Winters, 1984) performed tests where they varied the hydraulic conditions and reported the ability to remove the accumulated cuttings. In order to measure the ability of a jet stream to transfer energy to the bottom of the hole, they performed tests to measure the impact pressure under the bit. This impact pressure measured by (Warren and Winters, 1984) was compared with the expected impact pressure for a circular jet impact on a flat plate by (Sutko and Myers, 1971) given as

$$p_m = \frac{50}{1238.6 \cdot s^2} \cdot \rho \cdot d_{nozzle}^2 \cdot v_{nozzle}^2 \tag{5.13}$$

Where ρ [lbm/gal] represents the fluid density, d_{nozzle} [inch] and v_{nozzle} [ft/sec] is the diameter and the velocity through the nozzles respectively, s [inch] is the distance between the jet and the impact point and p_m[psi] is the resulting maximum impact pressure under the jet.

By comparing these two parameters, it is possible to measure the energy lost due to the fact that the jets flow into a confined space and the return fluid flow from under the bit creates a counterflow. Theoretically, the measured impact pressure should be independent of the nozzle size given a fixed bit size and the fixed impact force given as

$$F_j = 0.000516 \cdot \rho \cdot q \cdot v_{nozzle} \tag{5.14}$$

Where q [gal/min] is the flow rate, ρ and v_{nozzle} represents the fluid density and velocity as in equation (5.13).

In order to find a suitable measure for the hydraulic cleaning for different hydraulic conditions, (Warren, 1987) put up several plots. The first was a comparison of the measured peak impact pressure and the impact force from equation (5.14) for different jet sizes. He also put up a plot consisting of the same variables, looking at the effect they had on the rate of penetration. Based on the similarities in the two plots, (Warren, 1987) concluded that the peak impact pressure was a suitable way of measuring hydraulic cleaning.

The effect of the accelerated dispersion of the jet on the bottomhole cleaning for different jets and flow conditions was estimated with the use of empirical techniques. When the jets flow into reverse, the increased entrainment is a function of the ratio of the jet velocity and the return fluid velocity. Since the volumetric flow through the jets is equal to the return flow rate, the relative velocity can be estimated from the cross-sectional area of the nozzle and of the area around the bit that is available for flow return. The ratio of the jet velocity to the fluid return velocity is defined as follows (Warren, 1987)

$$A_v = \frac{v_{nozzle}}{v_{fluid\ return}} = \frac{0.15 \cdot d_{bit}^2}{3 \cdot d_{nozzle}^2} \tag{5.15}$$

Here it is assumed three nozzles and that only 15% of the bit area is available for fluid return flow. $v_{\text{fluid return}}$ [ft/sec] and v_{nozzle} [ft/sec] are the velocity of the fluid return and the velocity through the nozzles, d_{bit}[inch] and d_{nozzle} [inch] is the diameter of the bit and the nozzles respectively.

By making use of equation (5.13) and (5.15), it is possible to calculate the impact pressure for different nozzle sizes

$$p_m = (1 - A_v^{-0.122}) \cdot \frac{50}{1238.6 \cdot s^2} \cdot \rho \cdot d_{nozzle}^2 \cdot v_{nozzle} \tag{5.16}$$

The resulting maximum impact pressure under the jet is given in [psi]. The new impact force equation including the nozzle-size effects are given as

$$F_{jm} = (1 - A_v^{-0.122}) \cdot \ F_j \tag{5.17}$$

Where F_j [lbf] is the jet impact force. In order to come up with an equation for the rate of penetration that also included imperfect cuttings removal, dimensional analysis was used to isolate variables consisting of the modified impact force and the mud properties. (Warren, 1987) tried to combine these factors with equation (5.12) to come up with an equation to match the experimental data. He ended up with the given equation for rate of penetration estimation.

$$ROP = \left(\frac{a \cdot S^2 \cdot d_{bit}^3}{RPM \cdot WOB^2} + \frac{b}{RPM \cdot d_{bit}} + \frac{c \cdot d_{bit} \cdot \gamma_f \cdot \mu}{F_{jm}} \right)^{-1} \tag{5.18}$$

Where a-c are dimensionless constants, S [psi] is the rock strength, d_{bit}[inch] is the bit diameter, RPM [rev/min] is the rotational speed, WOB [lbf] is the applied weight on bit, γ_f is the dimensionless fluid specific gravity, μ [cp] is the plastic viscosity and F_{jm}[lbf] represents the modified jet impact force. This model proves that in order to maintain a particular rate of cuttings removal, the impact force needs to be increased as the bit size also increases (Warren, 1987).

5.3.3 Modified Warren

In the abovementioned formulas for rate of penetration, there are different effects on the calculation that are not included. Therefore, some modifications needed to be made to Warren's model in equation (5.18) in order for it to be more realistic. The first modification was purposed by (Hareland and Hoberock, 1993). With the modification given in equation (5.19), they intended to include the so-called chip hold down effect. This effect represents the resultant force a chip experience when it is generated by the drill bit (Rahimzadeh et al., 2010) and it is expressed as follows

$$f_c(P_e) = c_c + a_c \cdot (P_e - 120)^{b_c} \tag{5.19}$$

Where P_e [psi] is the differential pressure, a_c-c_c are constants dependent on the lithology and $f_c(P_e)$ represents the resulting chip hold down function.

Full-scale laboratory data from drill tests with varying bottom-hole pressure while remaining other conditions constant, have been used in order to come up with the relation in equation (5.19).

The resulting rate of penetration including this effect can now be calculated from Warren's imperfect cleaning model in equation (5.18) and the chip hold down effect in equation (5.19), giving the following expression

$$ROP = \left(f_c(P_e)\left(\frac{a \cdot S^2 \cdot d_{bit}^3}{RPM \cdot WOB^2} + \frac{b}{RPM \cdot d_{bit}}\right) + \frac{c \cdot d_{bit} \cdot \gamma_f \cdot \mu}{F_{jm}}\right)^{-1} \tag{5.20}$$

Where a-c are dimensionless constants, S [psi] is the rock strength, d_{bit}[inch] is the bit diameter, RPM [rev/min] is the rotational speed, WOB [lbf] is the applied weight on bit, γ_f is the dimensionless fluid specific gravity, μ [cp] is the plastic viscosity and F_{jm}[lbf] represents the modified jet impact force.

In addition to the abovementioned chip hold down effect, (Hareland and Hoberock, 1993) also modified Warrens model in equation (5.18) by introducing the effect of bit wear. In order to include bit wear they defined a wear function given as

$$W_f = 1 - \frac{\Delta BG}{8} \tag{5.21}$$

Where ΔBG represents the change in wear of the bit tooth and it can be calculated in terms of a bit wear coefficient W_c, WOB [lbf], RPM [rpm], relative abrasiveness Ar_{abr_i} and the confined rock strength, S [psi] which is a function of pressure and lithology given as

$$\Delta BG = W_c \sum_{i=1}^{n} WOB_i \cdot RPM_i \cdot Ar_{abr_i} \cdot S_i \tag{5.22}$$

$$S = S_0 \cdot \left(1 + a_s \cdot P_e^{b_s}\right) \tag{5.23}$$

The constants a_s and b_s are dependent on the permeability of the formation drilled, S_0[psi] represents the unconfined rock strength and P_e [psi] is the differential pressure. When including both the chip hold down effect and the bit wear, (Hareland and Hoberock, 1993) came up with the following final equation for the rate of penetration

$$ROP = W_f \cdot \left(f_c(P_e)\left(\frac{a \cdot S^2 \cdot d_{bit}^3}{RPM \cdot WOB^2} + \frac{b}{RPM \cdot d_{bit}}\right) + \frac{c \cdot d_{bit} \cdot \gamma_f \cdot \mu}{F_{jm}}\right)^{-1} \tag{5.24}$$

5.3.4 Mechanical specific energy model

As mentioned, the MSE-models can make it possible to enhance instantaneous rate of penetration by optimizing the drilling variables. This model provides a tool to monitor changes in the drilling efficiency during drilling.

In 1965, Teale made a paper that focused on fundamental problems and implications in rock working or mining operations. Teale was convinced that there had to be a relationship between energy and crushing of the rock drilled. Many studies have been performed showing that the energy applied for crushing defined by (Teale, 1965) can be related to the drilling process.

The relationship between the energy and crushing of rock was defined by the concept of specific energy, which represents the required energy or work to drill a given amount of rock. Teale was certain that it was a minimum value of energy in order to be able to drill this amount of rock. The formula for mechanical specific energy used today is based on the concept of specific energy defined by (Teale, 1965)

$$MSE = \frac{WOB}{A_b} + \frac{120\pi \cdot RPM \cdot T}{A_b \cdot ROP} \tag{5.25}$$

Here A_b [inch^2] is the bit surface area given as $A_b = \frac{\pi \cdot d_{bit}^2}{4}$, RPM [rev/min] is the rotary speed, ROP [ft/hr] is the rate of penetration, WOB [lbf] is the weight on bit, T [ft-lbf] represents the measured torque and the resulting MSE is given in psi.

Changes in drilling efficiency can be detected with the use of MSE monitoring. This can provide the possibility to optimize operating parameters (Rashidi et al., 2008). In order to make use of equation (5.25), a reliable value of torque have to be calculated separately. Torque at the bit can be measured using MWD, but (Pessier and Fear, 1992) came up with an expression for torque as a function of WOB, by modeling the bit as a simple, circular shaft with a flat bottom.

$$T = \mu \cdot \frac{d_{bit} \cdot WOB}{36} \tag{5.26}$$

Where d_{bit} [inch] is the diameter of the bit and WOB [lbf] is the applied weight on bit. In this equation is μ defined as a bit-specific coefficient of sliding friction, which is a dimensionless number with a specific number for both PDC-bits and roller-cone bits. By substituting equation (5.26) into equation (5.25), the following formula for the mechanical specific energy is obtained

$$MSE = WOB \cdot \left(\frac{1}{A_b} + \frac{13.33 \cdot \mu \cdot RPM}{d_{bit} \cdot ROP}\right) \tag{5.27}$$

Equation (5.27) can also be expressed in terms of rate of penetration (Pessier and Fear, 1992) given as.

$$ROP = \frac{13.33 \cdot \mu \cdot RPM}{d_{bit} \cdot \left(\frac{MSE}{WOB} - \frac{1}{A_b}\right)} \tag{5.28}$$

The main intention with the work of (Pessier and Fear, 1992) was to confirm and validate the concept of MSE for hydrostatic pressure since (Teale, 1965) only performed his tests under atmospheric conditions.

In order to make use of the models given in this section, several parameters and assumptions need to be determined. With the data available for this evaluation, it was not possible to obtain sufficient results by using these models. Due to this, it was decided not to use any of them in the further calculations and investigations, but they are included with the intention of showing that there are developed models to optimize drilling parameters in order to obtain the maximum rate of penetration.

6 Bit wear detection

This chapter will discuss some methods to detect bit wear that exists in the industry today. First, it will be discussed how to utilize real-time drilling data in the process of investigating bit wear. When using real-time drilling data in the investigations of the bit wear, downhole measurements from for instance the CoPilot tool will give results that are more accurate. When utilizing downhole data, the friction in the borehole is negligible because the CoPilot sub is placed near the bit. Second, it will be an introduction to a method of how to predict bit wear in real-time.

6.1 Indications of bit wear on drilling data

6.1.1 Weight on bit vs rate of penetration

The weight on bit is an important parameter to monitor during the drilling process. The changes in weight on bit can be used in the process of detecting bit wear. When looking at the weight on bit variations, it is important to distinguish between different formations. A hard formation has another response on the rate of penetration with an increase in weight on bit than a soft formation.

Increased weight on bit should ideally result in an increased penetration rate when drilling in the same formation. If this is not the case, it can be an indication that the bit is worn (Vikra, 2008). If more weight needs to be applied in order to obtain the same rate of penetration deeper in the well compared to earlier in the drilling process, the bit is most likely worn to some extent. After discussions with bit-, and drilling optimization experts in Lundin, it was decided to use the relationship between rate of penetration and weight on bit to determine the bit wear in Well and Well B.

6.1.2 Torque vs rate of penetration

In discussions with Lundin, it was concluded that torque is not a good indicator of bit wear because it does not give unambiguous answers. A PDC-bit use cutters to achieve progression in the drilling process. A new bit with sharp cutters give more resistance than worn bits with rounded cutters. When drilling through hard and difficult formations, the cutters are worn and/or damaged and become less aggressive, which again can result in a decreased torque. With that said, the opposite change in torque can also appear when the bit is worn. When the cutters are new they are sharp, which leads to a small contact area between the cutters and the formation. Worn down cutters will be flatter and have a larger contact area that can result in an increased torque. Therefore, it was decided to not further investigate torque or use this as an indicator for bit wear.

6.2 Real-time bit wear prediction

6.2.1 Intention

Many authors have stated that in order to reduce costs in the drilling process, real-time drilling data needs to be analyzed. The rate of penetration model by Bourgoyne & Young given in section 5.3.1 can be inverted in order to calculate the drillability of the formation. By changing the drilling parameters described in the model or the overall bit design, the model can be used as a tool to optimize the drilling process.

From equation (5.25) and (5.27) it can be seen that the MSE calculations do not include changes in mud weight or the bit wear, but the main advantage is that it is applicable in real-time. The effect of bit wear and changes in mud are on the other hand included in the rate of penetration model by Bourgoyne and Young given in equation (5.3). Therefore, by combining the two methods of drilling optimization, it is believed that the bit wear can be estimated real time. Ideally, this result can be used in the process of making the decision of when to pull the bit, which can potentially reduce drilling costs. The next section will introduce an approach to this problem presented by Rashidi, Hareland and Nygaard. They wanted to come up with a real-time bit wear prediction tool by analyzing offshore wells in the Persian Gulf and wells in Northern Alberta, Canada (Rashidi et al., 2008).

6.2.2 Calculations

To calculate the drillability, Rashidi, Hareland and Nygaard, used the inverse of the rate of penetration model given in equation (5.3) by (Bourgoyne and Young, 1974).

$$f_1 = \frac{ROP}{f_2 \cdot f_3 \cdot f_4 \cdot f_5 \cdot f_6 \cdot f_7 \cdot f_8} = drillability \tag{6.1}$$

In order to make use of this model, all the variables described in equation (5.5)-(5.11) have to be determined for each meter. The fractional bit wear was simplified and assumed to linearly decrease with depth as follows

$$h = \left(\frac{Depth_{current} - Depth_{in}}{Depth_{out} - Depth_{in}}\right) \cdot \frac{DG}{8} \tag{6.2}$$

Here DG is the IADC dull grade bit wear state and it is divided by 8 so that the bit wear ranges between 0 and 1 (Rashidi et al., 2008).

They wanted to combine this drillability with the formula for MSE, given in equation (5.27), and they first suggested the relationship in the power form given as

$$MSE = K_1 \cdot \left(\frac{1}{f_1}\right)^{K_2} \tag{6.3}$$

The constants K_1 and K_2 are field dependent. After plotting the calculated MSE values against the inverse of drillability for the wells in Alberta and in the Persian Gulf, (Rashidi et al., 2008) concluded that a linear relation was a better fit than the power relation that was first suggested. When analyzing the K_1 value with increasing depth, it was concluded that it had an increasing trend. To adjust for this trend they introduced a normalized inverted K_1 given as

$$norm\left(\frac{1}{K_1}\right) = 1 - h^B \tag{6.4}$$

Linear regression was used on order to find the constant B. The final step in this approach to obtain a real-time bit wear predictor was to find a relation between the reported fractional bit wear and the calculated B constant. After correlating B against the fractional bit wear for each bit run they came up with the following relationship between the two

$$B = 0.4212 + 5.6392 \cdot h \tag{6.5}$$

The final equation for real-time detection of bit wear is obtained by inserting equation (6.5) into (6.4). This study performed by Rashidi, Hareland and Nygaard shows promising results on the wells investigated in the Persian Gulf and in Alberta, Canada (Rashidi et al., 2008).

Difficulties can occur when trying to achieve a good relationship between the MSE and the drillability. Other variables than the ones included in the MSE equation given in (5.27) can also affect the results such as bit balling, variations in hydraulic and mud viscosity (Nygaard, 2016). Therefore, it was decided to use the methods to detect bit wear described in Section 6.1 when analyzing the data in the investigations in Chapter 7.

7 Observations and discussion

As stated previously, the rate of penetration is affected by many different factors. In this thesis, the focus are on formation density as an indicator of formation hardness, the applied weight on bit and the bit wear caused by the drilling process. Drilling data and formation data have been evaluated to find evidence of bit wear during the drilling process of Well A and Well B.

7.1 Data basis

The results in this thesis are based on data provided by Lundin Norway AS and discussions with drilling engineers, geologists, petrophysicists and bit- and drilling optimization experts within the company. All the calculations and evaluations are performed on the 8 ½" horizontal reservoir section in the two wells.

Downhole drilling data from the CoPilot was only available for well B and for well A the surface drilling data was utilized in the evaluations. In addition, the StarTrak image data and lithology data was used to be able to distinguish between different formations. The two main categories of formation investigated in this evaluation are sandstone and conglomerate.

This chapter includes both an investigation of bit wear in both Well A and Well B and an evaluation of correlations between lithology and drilling data for Well B.

7.2 Data modifications

Before the calculations and results are given, some modifications performed on the data and important features of the downhole drilling data are discussed.

Final well report for both of the wells was utilized in order to find out how the drilling process had been performed and to find out important notifications about the drilling process through the reservoir section of interest.

When drilling challenging formations such as conglomerate, it is a possibility of impact damage to the drill bit. This impact damage can destroy the bit within just a few meters. Lundin Norway AS in cooperation with various bit vendors have studied different PDC-cutters and developed cutters to withstand this impact damage. Therefore, in this study it is assumed that the drill bit is gradually worn when drilling consecutive intervals of conglomerate.

Facies data from the geologists was utilized as a basis for the formation determination. To be able to distinguish between different formations and making sure that the evaluations and calculations were performed on the same lithology, formation data and image logs were used. The formation data consists of gamma ray, density and neutron logs and an interpreted lithology as seen in Figure 7.1

Sub-surface data have been used to identify causes of spikes in the drilling parameters and formation data that are not representative for clear sandstone or conglomerate. When calculating an average value for rate of penetration, weight on bit and formation density, these intervals are excluded. An example of such an interval within a sandstone zone in Well B is given in Figure 7.1. A more detailed description of the excluded intervals are given in Appendix B-E.

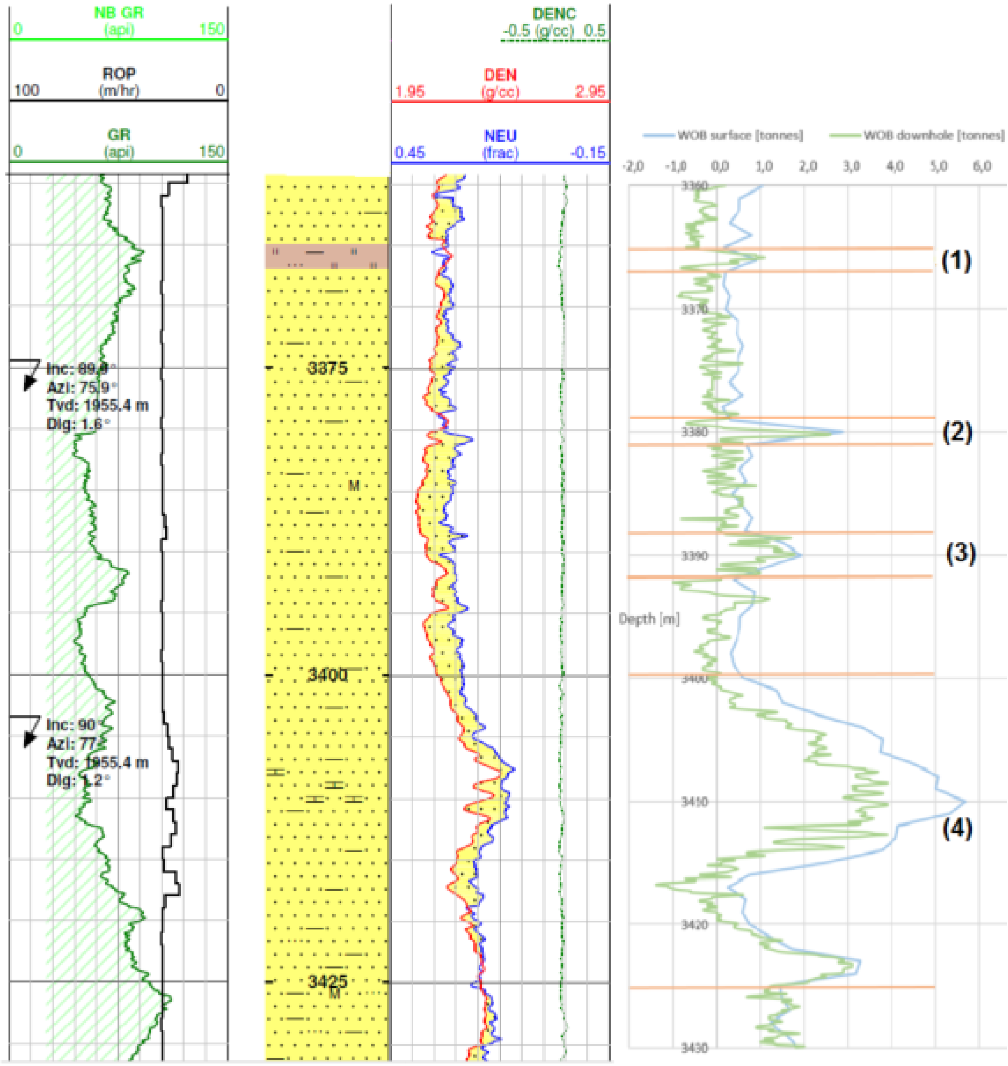

Figure 7.1: Example of excluded intervals for a sandstone zone in Well B

As depicted in Figure 7.1, four intervals are excluded based on either the interpreted lithology, the image log or the density of the formation, in order to obtain intervals consisting of formation with as similar properties as possible. Interval (3) was excluded due to reduced quality in the image log.

An important issue to be aware of is that in order for the numerical values from the CoPilot to be exact and correct, the tool needs to be calibrated when the bit is off bottom and for each new pipe stand. If the CoPilot is calibrated when weight is applied, it will give negative values when the bit is off bottom. To save rig time, this calibration was not performed often enough when drilling Well B. This caused the numerical values of the downhole weight on bit to be both less than zero and bigger than the surface weight on bit in certain intervals.

Because of this, the downhole data have only been used as an indicator of the downhole conditions and as a tool to look for trends in the drilling parameters and to detect bit wear. The numerical value has not been used in any calculations.

If the calibration procedure had been performed correctly, the downhole measurements could have been used directly to calculate and evaluate bit wear. The CoPilot sensor is placed in the bottom hole assembly, so the friction forces in the hole can be ignored. This means that if the downhole weight on bit has to be increased in order to achieve the same rate of penetration when drilling the same formation, it is most likely due to just bit wear alone and not the increased friction in the extended hole.

7.3 Reported bit wear

The bit used in the drilling process is analyzed and categorized after it is pulled according to the system described in section 3.6. Table 7.1 presents the bit wear characteristics for the bits used in Well A and Well B.

	Well A	Well B
Meters drilled	2313-3259	3200-3700
Bit info	NOV bit: E1270-A1	NOV bit: E1270-A1
Bit dull	8-6-CR-C-X-2-LN-PR	5-3-RO-N-X-1-WT-PR
Inner cutting structure	8/8	5/8
Outer cutting structure	6/8	3/8
Dull characteristics	Cored	Ring out
Location	Cone	Nose
Bearing/seal	x	x
Gauge	1/8" out of gauge	In gauge
Other dull characteristics	Lost nozzle	Worn cutters
Reasons pulled	Penetration rate	Penetration rate

Table 7.1: Bit wear characteristics for the bit used in Well A and B

A more detailed explanation about the characteristics in Table 7.1 are given in section 3.6 and Appendix A. It can be concluded from this table that the bit used in Well A is completely worn down and broken, resulting in a pulling action of the bit due to the fact that it is impossible to achieve the desired rate of penetration. The bit came out of the hole under-gauge and with lost nozzles as depicted in Figure 7.2.

Figure 7.2: Completely worn bit from Well A

Clearly, the bit from Well A is completely worn down and damaged, causing the drilling progress to stop. After discussions with bit experts and personnel in Lundin Norway it was concluded that the bit was worn down during the entire interval, but the fatal wear causing the damage shown in Figure 7.2 has taking place the last few meters drilled. Otherwise, the bit would not be able to maintain the rate of penetration that has been reported through the interval.

Figure 7.3: Worn cutters on the bit from Well B

Figure 7.3 depicts the bit used when drilling Well B. It can be seen that the cutters are worn around the entire bit. According to the reported bit wear given in Table 7.1, the bit is worn both at the outer and inner structure, which is evident when looking at the pulled bit in Figure 7.3.

7.4 Indications of bit wear

Calculations and evaluations are based on the theory that when the bit is worn, a higher weight on bit need to be applied in order to achieve the same rate of penetration as for a new bit when drilling the same type of formation. This section uses rate of penetration, weight on bit and formation density measurements that is verified through cuttings analysis in order to detect whether these data can be used to find evidence of bit wear in both Well A and Well B according to this theory.

7.4.1 Well A

After categorizing the reservoir section into different sandstone and conglomerate intervals, the rate of penetration and weight on bit was plotted against depth for Well A and the result is given in Figure 7.4. Yellow facies represent sandstone, dark blue represent conglomerate and the lighter blue facies is a collection of facies different than the other two. A more detailed illustration of the drilling parameters for each of the intervals is given in Appendix B and Appendix C.

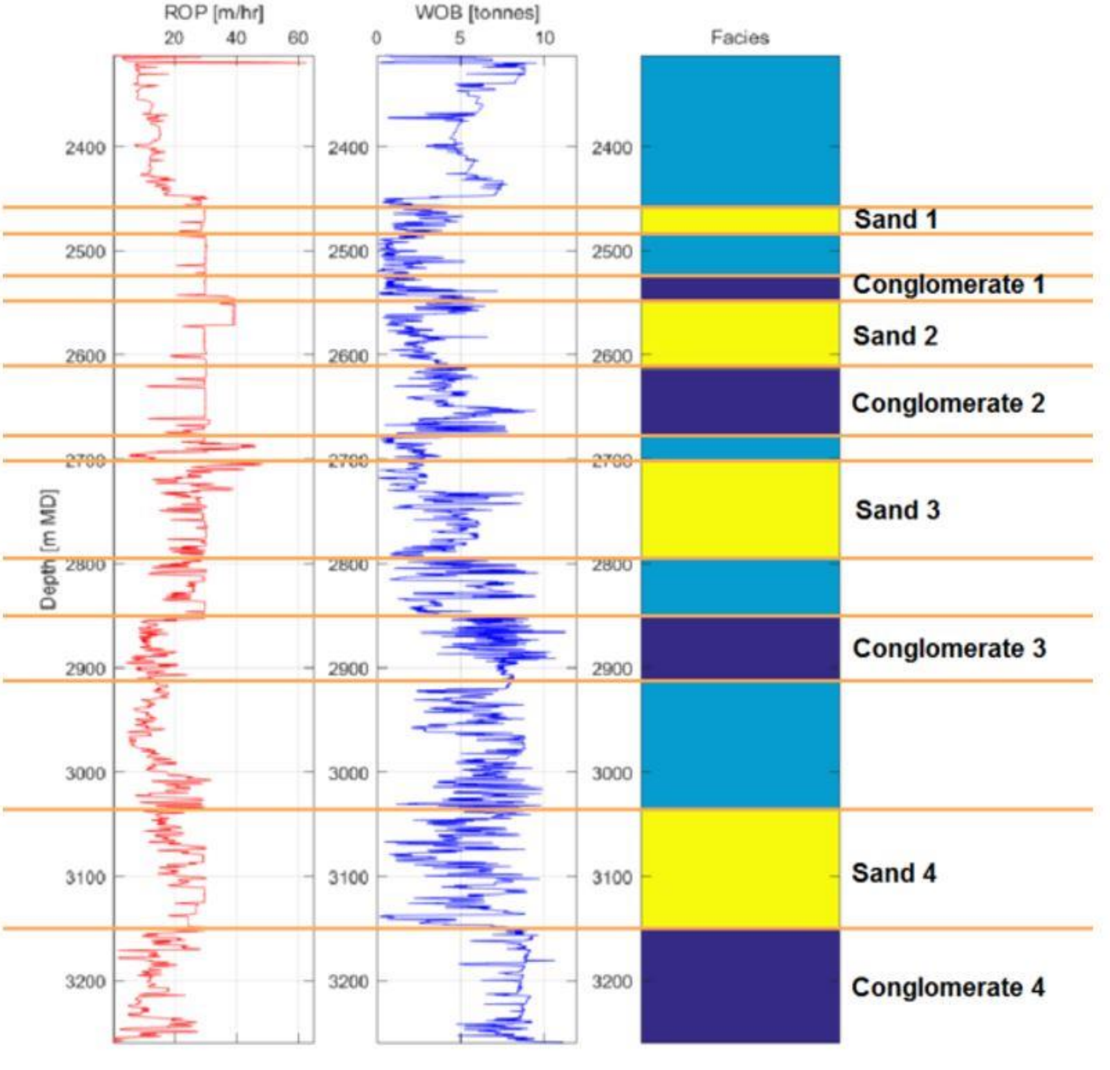

Figure 7.4: Drilling parameters in the different formations in Well A

In order to detect and find evidence of bit wear in the well, an average value for rate of penetration, surface weight on bit and formation density was calculated for the sandstone and conglomerate intervals indicated in Figure 7.4. The results are given in Table 7.2.

Lithology	Interval	ROP avg	WOB avg	Density avg
Sand 1	2460-2484	28.4	2.8	2.25
Sand 2	2550-2612	32.6	2.8	2.30
Sand 3	2701-2792	27.6	3.7	2.25
Sand 4	3034-3159	22.5	5.6	2.10
Conglomerate 1	2523-2549	31.5	2.3	2.40
Conglomerate 2	2613-2677	28.3	4.3	2.40
Conglomerate 3	2852-2912	12.9	7.3	2.43
Conglomerate 4	3160-3255	13.6	8.3	2.35

Table 7.2: Drilling parameters and formation density for Well A

The reported weight on bit for Well A in Table 7.2 is measured at surface. Therefore, it is important to keep in mind that the increased friction in the borehole as the well is extending and building angle influence the needed weight on bit, in addition to the bit wear.

The density measurements have been included to indicate the hardness of the formation drilled. It can be concluded from the intervals given in Table 7.2 that in general the density of the conglomerate zones are 0.17g/cc higher than in the sandstone zones. This would affect the rate of penetration and the weight on bit. When plotting the results from the sandstone and conglomerate intervals given Table 7.2 it is easier to detect patterns in the data and the graphical illustrations are given for sandstone in Figure 7.5 and conglomerate is depicted in Figure 7.6.

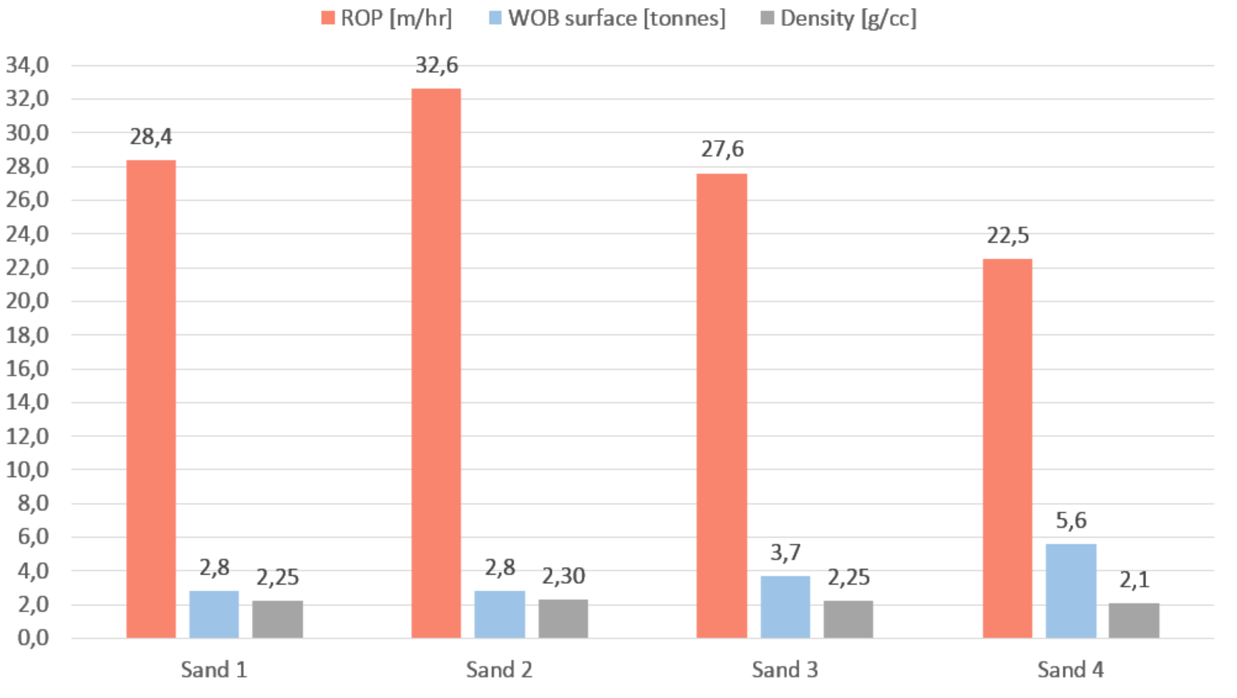

Figure 7.5: Graphical illustration of the sandstone intervals in Well A given in Table 7.2

From Figure 7.5 it can be seen that Sand 1 and Sand 3 have the same average density of 2.25g/cc, but the weight on bit in Sand 3 is higher and still the rate of penetration is lower. This trend also goes for the zone indicated as Sand 4, which have the lowest average formation density and still it have the highest weight on bit and the lowest resulting rate of penetration of all the sandstone zones. This is interpreted to be indications of bit wear in the data investigated when drilling Well A.

The reason for a higher rate of penetration in Sand 2 compared to Sand 1 could be minor changes in for instance the permeability. The driller also utilized an Autodriller function and tried a higher rate of penetration for a few meters in the start of Sand 2 interval as seen in Figure 7.4

When plotting the data for conglomerate given in Table 7.2, the same trend as in the sandstone intervals can be seen. The graphical illustration of the data is given in Figure 7.6.

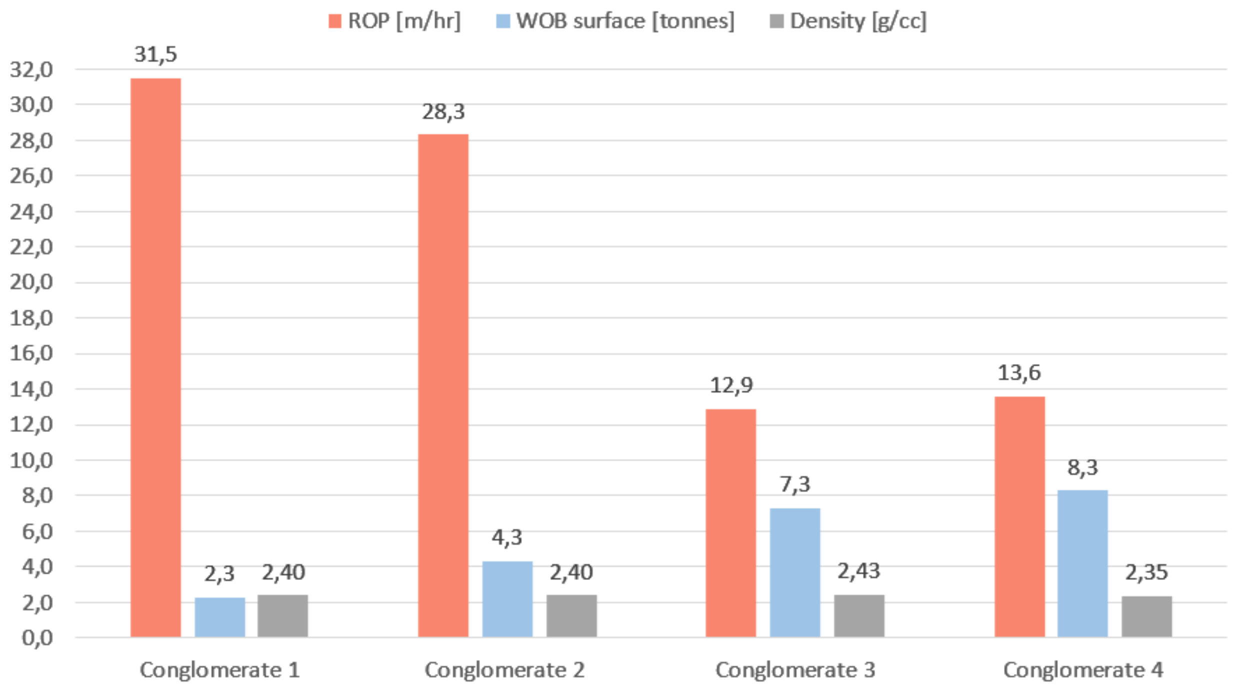

Figure 7.6: Graphical illustration of the conglomerate interval from Table 7.2

The first three intervals of conglomerate have a steady increase in the applied weight on bit and a steady decrease in the rate of penetration, while the density of the formation is approximately the same. In the last conglomerate interval, the formation density drops to 2.35g/cc and still the weight on bit increases in order to maintain the rate of penetration from Conglomerate 3. As for the sandstone zones, this is interpreted to be indications of bit wear.

When drilling this well an Autodriller was utilized in order to restrict the rate of penetration to 30m/hr due to logging tools that was used in the drilling operation. The weight on bit was adjusted to maintain the desired rate of penetration, but due to the possibility of buckling of the drill string the weight could not exceed a certain level. When looking at the drilling data given in Figure 7.4 it can be concluded that a rate of penetration of approximately 30m/hr is obtained with a relatively low weight on bit all the way down to 2850m MD. From this depth it can be seen that the rate of penetration has a decreasing trend even though the weight on bit is steady or increasing. When looking at the average values in Table 7.2 this observation is more evident. Sand 4, Conglomerate 3 and Conglomerate 4 have an average rate of penetration way below 30m/hr and the weight on bit in these sections are also increasing steady.

All of the observations given above are indications of bit wear when analyzing the drilling data and the formation characteristics from the drilling process through the reservoir section consisting of sandstones and conglomerates.

7.4.2 Well B

As for Well A, the rate of penetration and the weight on bit for Well B was plotted against depth after categorizing the reservoir section into different sandstone and conglomerate intervals as depicted in Figure 7.7. To simplify the illustration, only the main lithology zones are indicated in Figure 7.7, but within these zones are intervals that are excluded from the calculation as explained in section 7.2. A more detailed illustration of these excluded intervals is given in Appendix D and Appendix E.

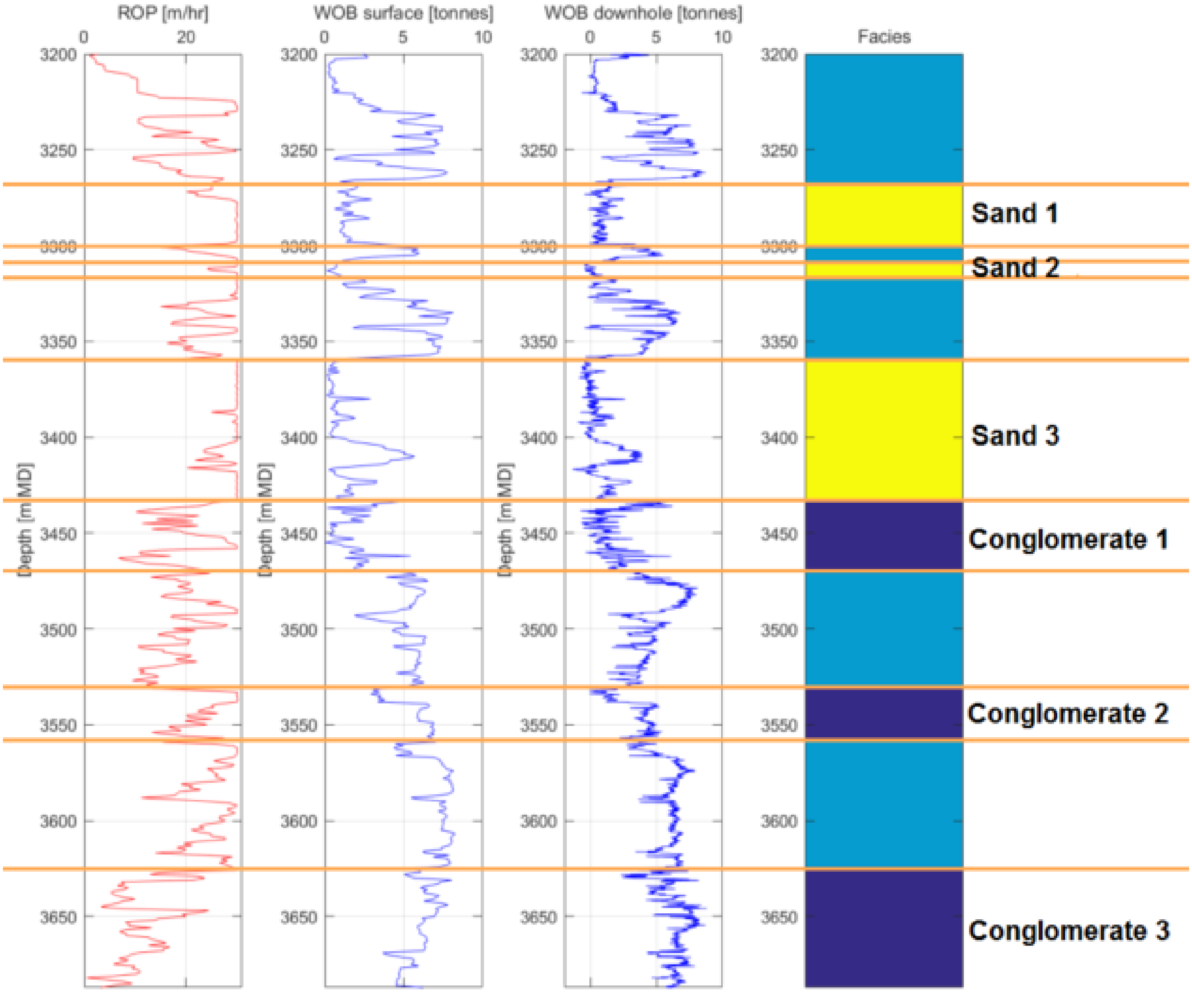

Figure 7.7: Drilling parameters in the different formations in Well B

In the facies illustration in Figure 7.7 are sandstone zones given a yellow color, conglomerate a dark blue and the lighter blue color represents a collection of facies different than the other two.

As for Well A, the average rate of penetration, surface weight on bit and formation density was calculated in order to find indications of bit wear. In this well, the CoPilot tool was utilized during drilling so the average value for downhole weight on bit was also calculated for the different sandstone and conglomerate intervals given in Figure 7.7. The results are given in Table 7.3.

Lithology	Interval	ROP avg	WOB avg surface	WOB avg downhole	Density avg
Sand 1	3269-3299	28.5	1.5	0.9	2.20
Sand 2	3309-3315	28.2	0.6	-0.1	2.17
Sand 3	3360-3365	30.0	0.6	-0.4	2.15
	3368-3379	30.0	0.4	-0.1	2.15
	3382-3388	29.1	0.6	0.2	2.10
	3392-3399	30.0	0.6	-0.1	2.15
	3426-3431	30.0	1.6	1.4	2.40
Total Sand 3		29.8	0.7	0.2	2.19
Conglomerate 1	3432-3438	23.3	3.0	4.0	2.45
	3459-3470	14.1	2.5	2.2	2.40
Total Conglomerate 1		18.7	2.8	3.1	2.43
Conglomerate 2	3530-3534	23.5	3.4	0.9	2.30
	3539-3542	25.1	6.5	4.6	2.32
	3551-3557	18.2	6.8	4.2	2.35
Total Conglomerate 2		22.3	5.6	3.2	2.32
Conglomerate 3	3624-3646	12.2	6.6	5.5	2.42
	3650-3662	10.7	6.2	7.2	2.40
	3671-3680	8.8	5.2	6.7	N/A
Total Conglomerate 3		10.6	6.0	6.5	2.41

Table 7.3: Drilling parameters and formation density for Well B

In Figure 7.7 are the main intervals of sandstone and conglomerate marked for simplicity, even though there are zones within these intervals that are not representative for clean sandstone or conglomerate. Only the clean intervals are listed in Table 7.3 and zones with different formation characteristics are excluded from the calculation of the average values, as explained in section 7.2. Therefore, the numbers marked as total in the table are an average value of just clean sandstone and conglomerate in order for the calculations to be representative for the different lithologies.

As seen in Table 7.3, the downhole weight on bit is sometimes below zero and even greater than the surface weight. The reasons for this are briefly explained in section 7.2 and the numerical value of this parameter is not used directly, just as a tool to look for trends and patterns within the intervals. When looking at both Figure 7.7 and Table 7.3 it is evident that the surface and downhole weight on bit more or less follows the same trend.

When looking at the last interval of Sand 3 it is interpreted that this is a sign of a transition zone from sand to conglomerate. The high density of the formation is similar to the conglomerate zones detected deeper in the well. The rate of penetration is high even with relatively low weight on bit; therefore this interval is included when calculating the average values for sandstone given in Total Sand 3.

In order to make the patters in the data more evident, the results from Table 7.3 are plotted and the graphical illustrations are given for sandstone in Figure 7.8 and conglomerate is depicted in Figure 7.9.

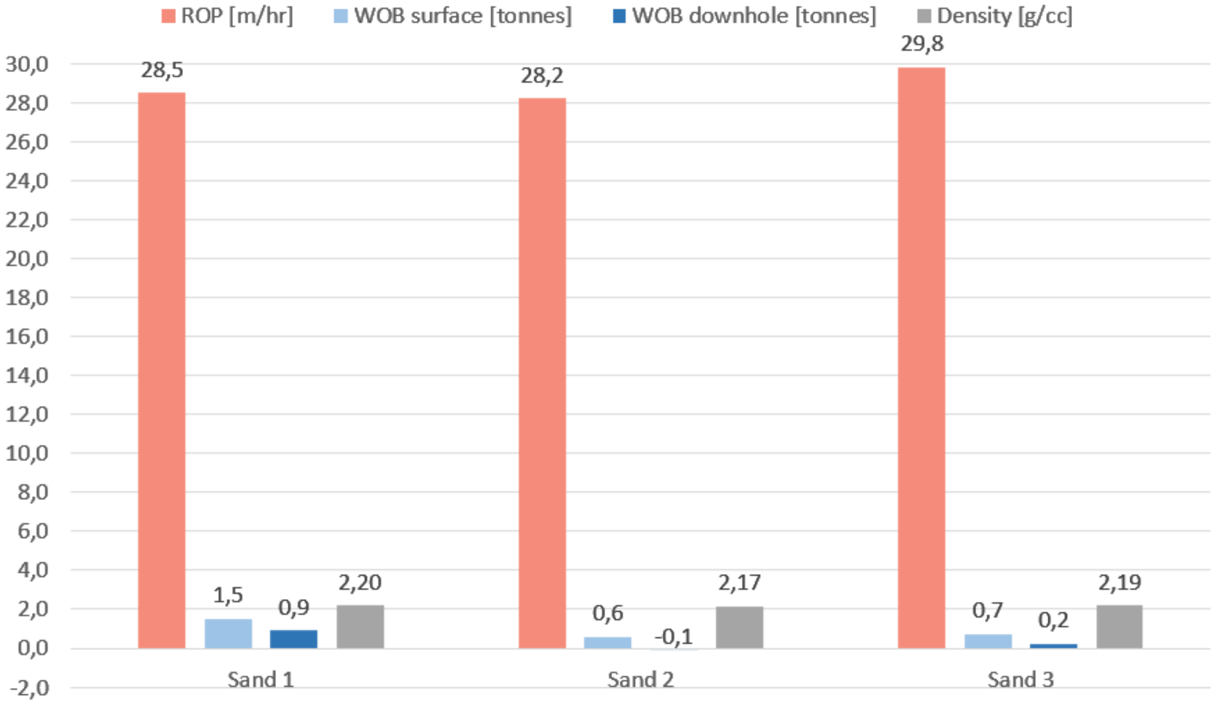

Figure 7.8: Graphical illustration of the sandstone intervals in Well B given in Table 7.3

From Figure 7.7 it can be seen that all the three sandstone zones are drilled before the difficult conglomerate zones are present in the well. After discussions with Lundin Norway, it was clear that a high rate of penetration through sandstones can be achieved with relatively low weigh on bit and the drilling process normally causes limited bit wear. When looking at the graphical illustration of the results for sandstone given in Figure 7.8, there are evidence to support this statement. All the three sandstone zones have a high rate of penetration close to the desired 30m/hr set by the Autodriller, obtained with a relatively low weight on bit. The formation density, the rate of penetration and the applied weight on bit is relatively similar in the three sandstone zones, which is an indication that the bit is not yet experiencing significant wear from the drilling process. As given in Table 7.1, the bit have been worn down during drilling of this well. Since the results given in Figure 7.8 show that the bit is not yet experiencing wear after the sandstone intervals, it is conclude that the bit experience more aggressive wear when drilling the conglomerate sections.

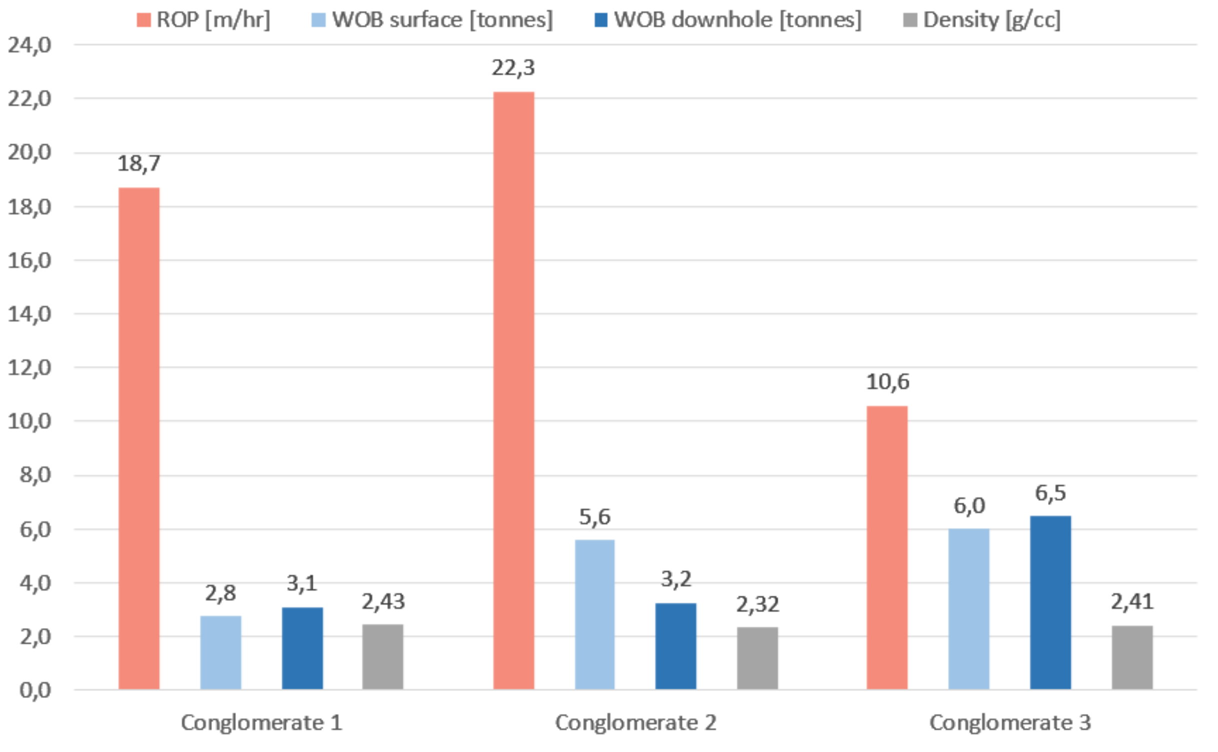

Figure 7.9: Graphical illustration of the conglomerate intervals in Well B given in Table 7.3

When entering the conglomerate zones, both the formation density and the drilling data are significantly changed from the sandstone as shown in Figure 7.9. The same trend that was seen in Well A for the average formation density is also evident for Well B. The average formation density in the three conglomerate zones is approximately 0.2g/cc higher than for the sandstone zones. The rate of penetration is significantly lower even with a higher weight on bit. These characteristic differences indicate that the formation density and the drilling parameters can be used in order to separate the two lithologies and that there are correlations between the formation data and the drilling data. This will be investigated further in section 7.5 for Well B.

From Figure 7.9 it can be seen that Conglomerate 1 and Conglomerate 3 have very similar formation density compared to Conglomerate 2, so it would be of interest to compare the drilling parameters in these sections to look for indications of bit wear. Conglomerate has very different characteristics with regards to fragment size and hardness as mentioned in section 3.1. Therefore, the image log from both sections investigated were used in order to make sure that these zones had similar characteristics. Figure 7.10 shows a comparison of two representative intervals from the image log within Conglomerate 1 and Conglomerate 3. It can be seen that the two intervals have very similar characteristics, verifying that it is decent to compare the two intervals of conglomerate to look for indications of bit wear.

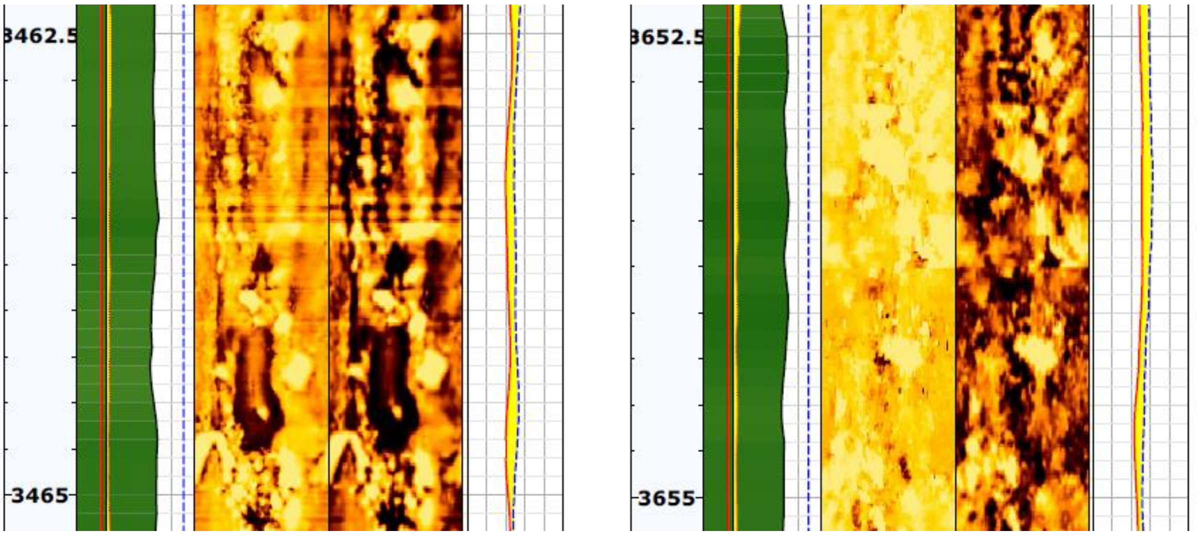

Figure 7.10: Comparison of Conglomerate 1 (left) and conglomerate 3 (right) from Well B

Conglomerate 1 and Conglomerate 3 have approximately the same formation density of 2.42g/cc. If the bit was intact and not worn, this should ideally result in the same rate of penetration given the same downhole weight on bit. By looking at the average values given in Total Conglomerate 1 and Total Conglomerate 3 in Table 7.3 and the graphical illustration in Figure 7.9, it is evident that the rate of penetration has a steep decreasing trend even with a significantly increased weight on bit. This has been interpreted as evidence that the drill bit is more worn when drilling the last zone of conglomerate.

Both of the wells evaluated are located at the Edvard Grieg field and they both drill a reservoir section consisting of sandstone and conglomerate, which have caused both drill bits to be significantly worn and damaged. By analyzing drilling data and formation characteristics, indications of bit wear have been investigated by using the theory that a worn bit will need more applied weight on bit in order to achieve the same rate of penetration when drilling the same lithology. The graphical illustrations for the sandstone and conglomerate intervals from both Well A and Well B, shows identical patterns. Ideally, could more wells be included in the evaluations, but since the patterns are evident in both wells, the conclusions are made based on the analysis of the two wells.

7.5 Data correlations for Well B

The results from section 7.4 indicate that there are correlations between the drilling data and the formation data. When looking at the drilling data and the formation characteristic for the entire reservoir sections, it was evident that this correlation was present and this section demonstrates specific examples of this. Since downhole drilling data are only available for Well B, data correlations have only been evaluated for this well. The downhole drilling data from the CoPilot are together with StarTrak image data and formation data used to detect correlations.

The image log provides a high-resolution resistivity log of the formation, which can identify geological and borehole features. This log represents the entire borehole diameter, where the bottom of the hole is depicted in the middle of the log. From the formation data, the density and the neutron logs were used as an indicator of the hardness of the formation. The geologists have verified the density log with the use of cuttings analysis.

When detecting correlations for Well B, both the downhole WOB and surface WOB from Figure 7.9 was investigated and areas of interest are depicted in Figure 7.11.

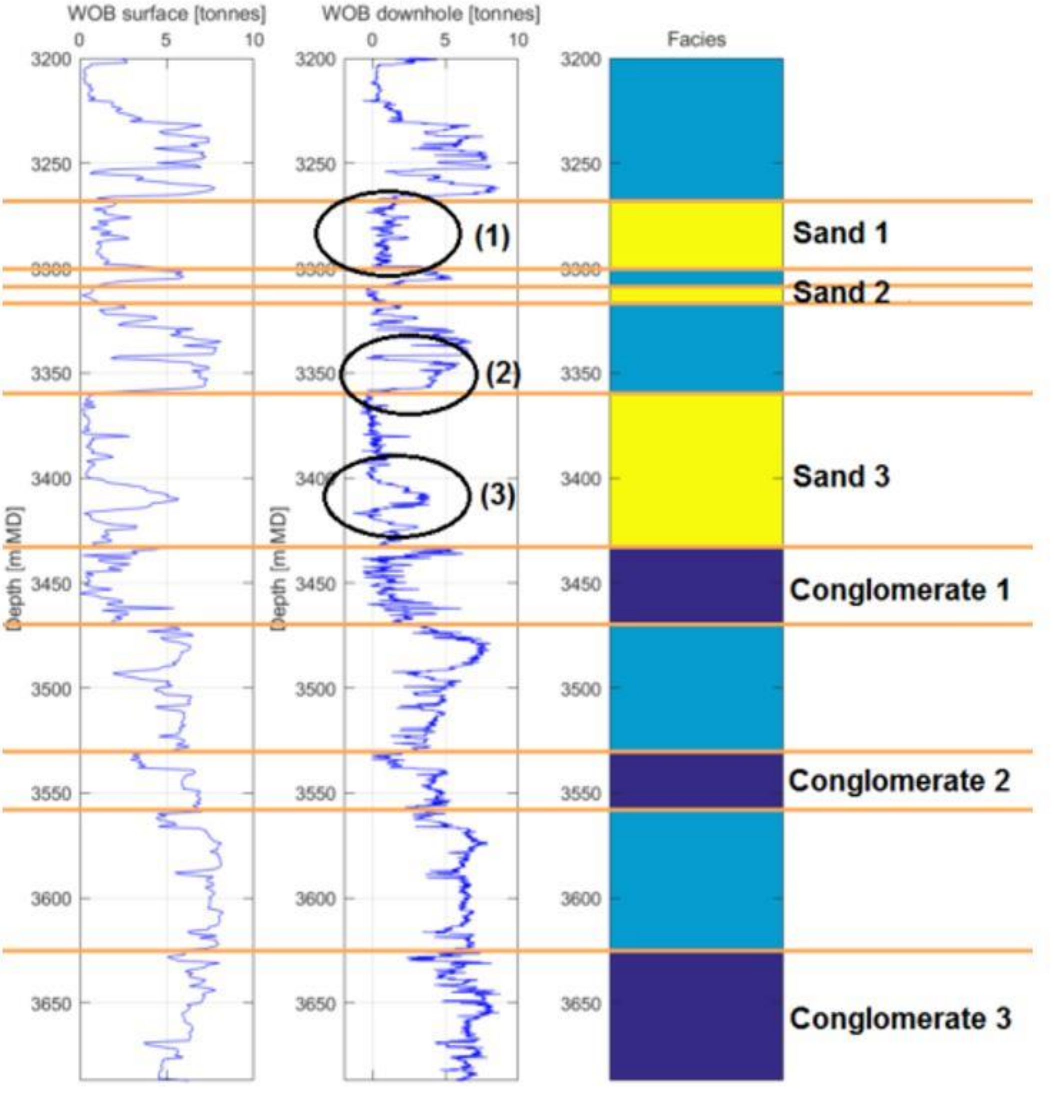

Figure 7.11: Areas of interest concerning correlations in Well B

The three areas marked by the circles (1)-(3) are areas that have been taken into further considerations and evaluations due to the characteristic behavior in the downhole weight on bit.

The first area to investigate further is within the first sandstone zone marked by **Circle (1)** in Figure 7.11A steady decrease in both the downhole and surface weight on bit can be evidence of a formation with decreasing hardness and increasing drillability. In order to investigate this further, different formation logs was utilized.

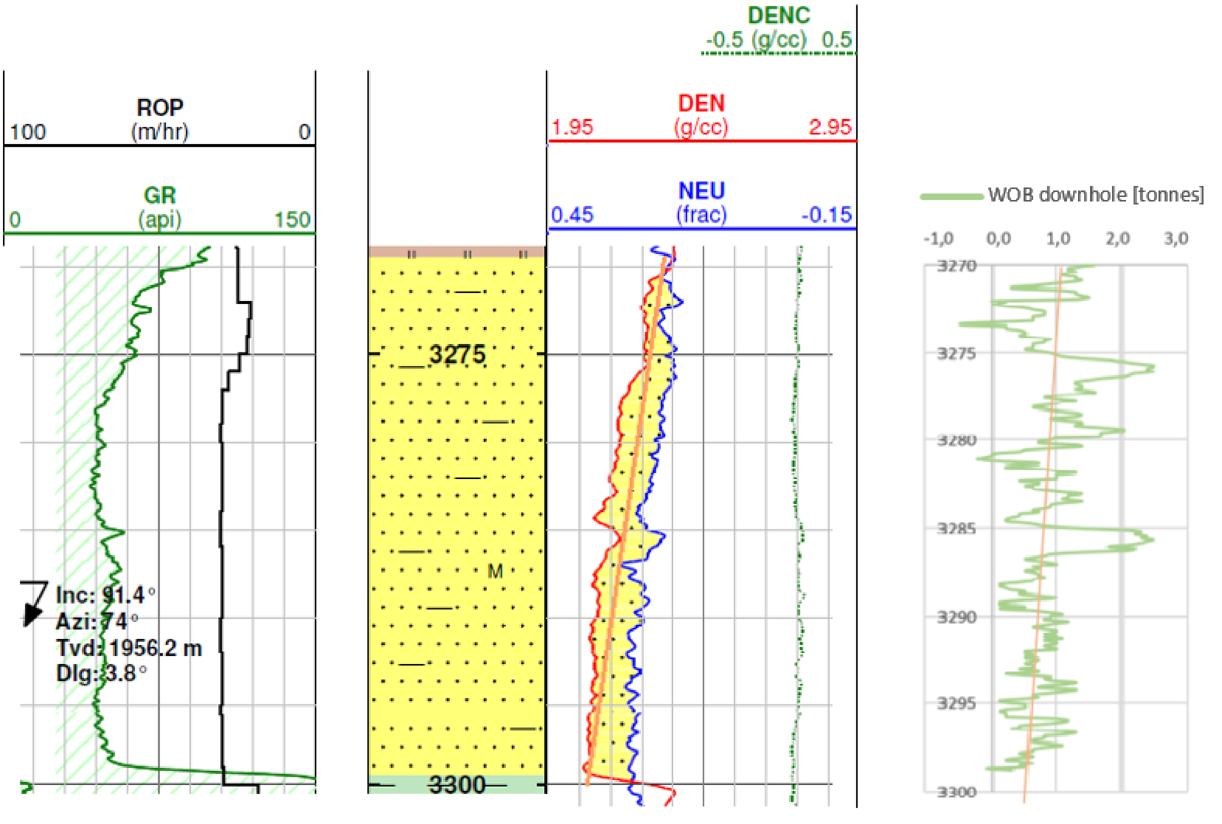

Figure 7.12: Correlations between drilling parameters and lithology from Circle (1)

From Figure 7.12 it can be seen that from 3277m MD the weight on bit can be reduced in order to achieve the same rate of penetration of approximately 30m/hr. This is interpreted as an effect of increased drillability in the formation. When looking at the log for density and neutron, it is observed that the density of the formation also decreases steady through the same interval, which represents a transition to rocks that are more porous and easier to drill. Due to this observation, it is concluded that there are correlations between the drilling data and the formation characteristics. Another example to support this statement within this zone is that the peak in weight on bit at 3286 m MD can also be seen as an increased density of the formation. The two graphs are corresponding very well and is more or less following the same trend through this interval.

The next area that has been investigated in this thesis is indicated by C**ircle (2)** in Figure 7.11. The downhole weight on bit have a moderately decreasing trend starting from approximately 3353 m MD until it suddenly drops and stabilizes on the minimum weight on bit experienced in the whole reservoir section, as depicted in Figure 7.13.

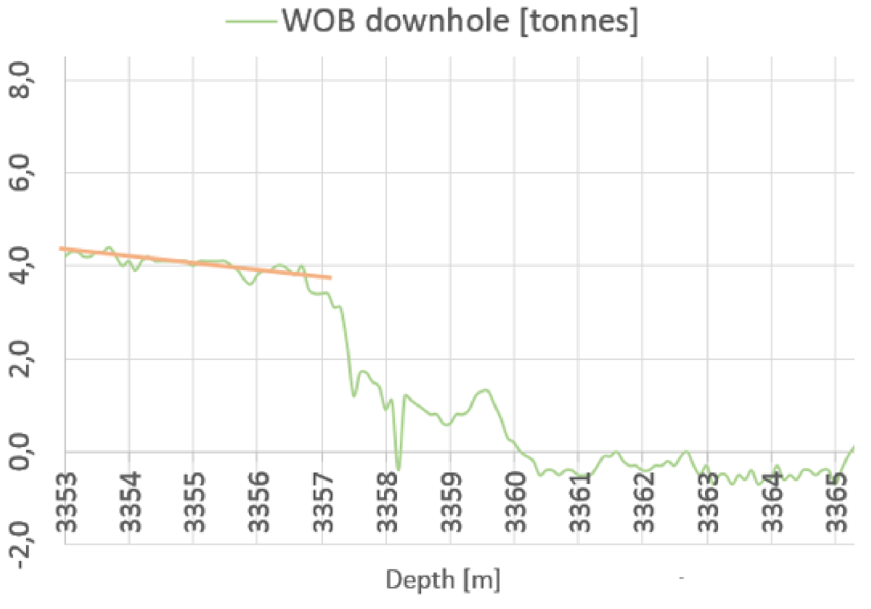

Figure 7.13: Downhole weight on bit in the transition zone from Circle (2)

In order to interpret what caused this trend in the weight on bit, the StarTrak image log was utilized. The image log can visualize the different formations including its dip and strike angle. If a horizontal well hits a formation layer with a low dip angle, which makes it nearly parallel to the wellbore, it will be a certain distance before the entire borehole and bit is entering the new formation. This can cause a delay in the response on the drilling data to these new formation properties.

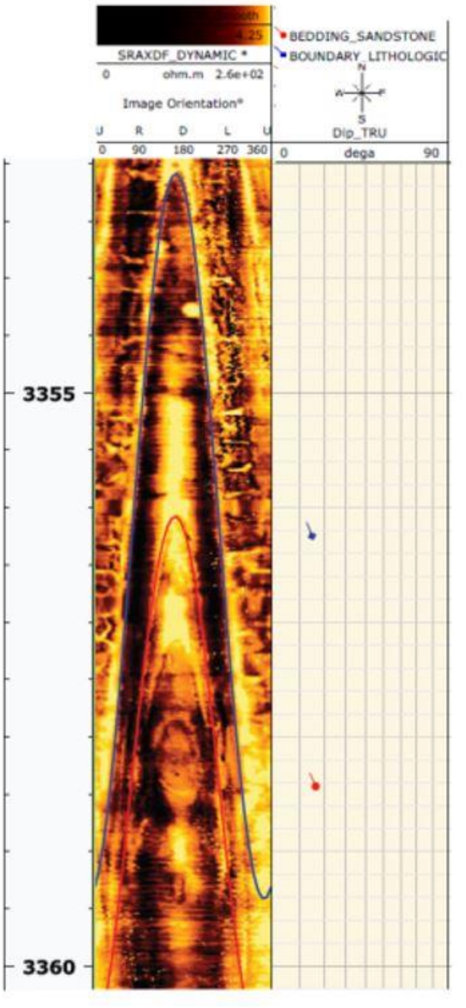

Figure 7.14: Image log from the lithological boundary

When looking at the image log given in Figure 7.14, it is evident that at approximately 3353m MD a new surface is detected, indicated by the blue contour. Since the contour starts in the middle of the log and is slowly propagating to the edges, the wellbore hits the layer with the bottom first. Due to the low angle between the wellbore and the layer, it takes a certain distance before the entire wellbore is entering the formation. At approximately 3360 m MD the contour is covering the entire hole, meaning that the well have completely entered the new formation, as depicted in Figure 7.14. After discussions with drilling engineers and petrophysicists in Lundin, this is an interpretation of why the downhole weight on bit have a slow response to the new formation. In addition to the observation in Circle (1), this is an indication that there are correlations between drilling data and formation characteristics.

The final interval that has been evaluated to detect any correlation between drilling parameters and the formation data is the interval marked by **Circle (3)** in Figure 7.11. From 3400-3420m MD, there are a peak in both the surface and the downhole weight on bit. Formation data was utilized in order to identify whether this increase was related to the drillability and the hardness of the formation being drilled.

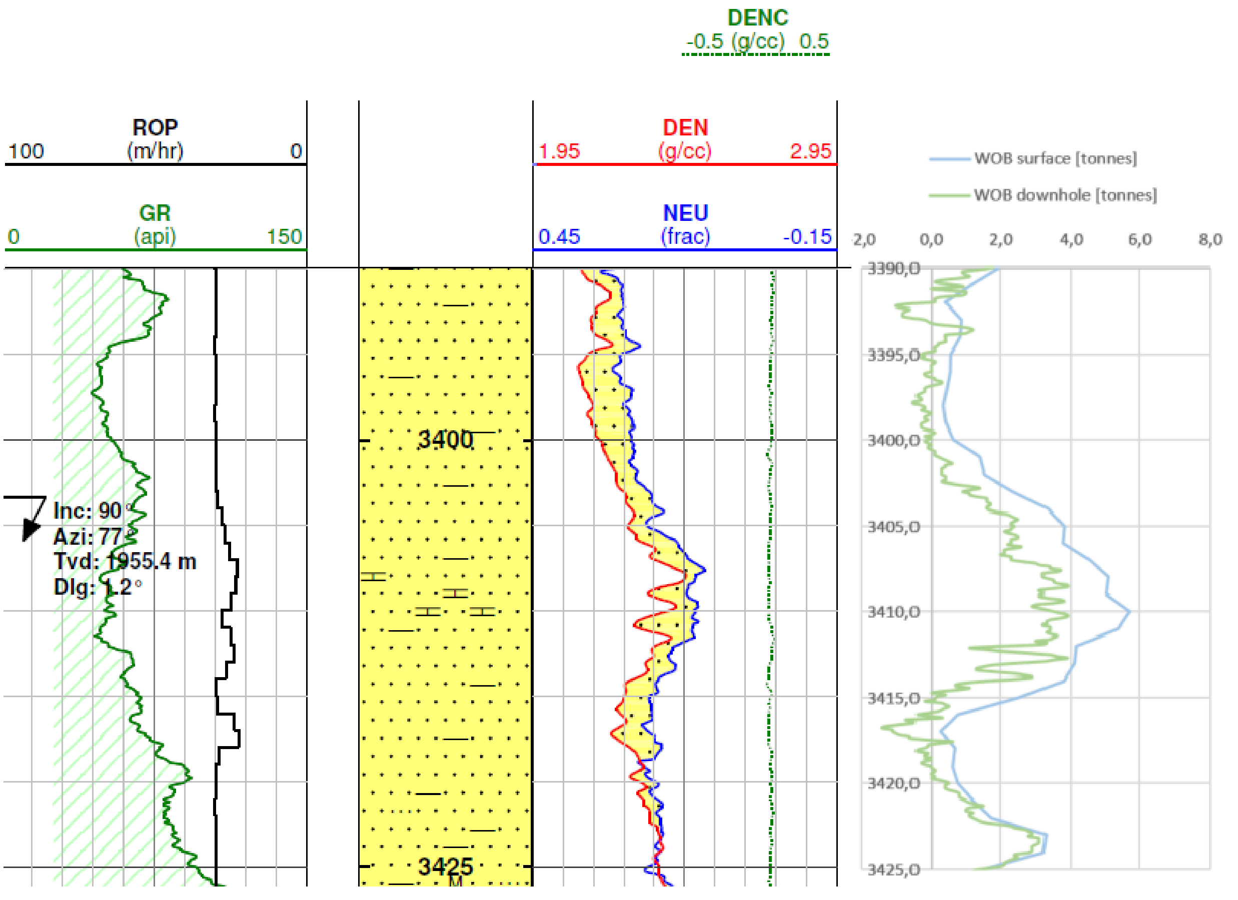

Figure 7.15: Correlations between formation and drilling data in Circle 3

Figure 7.15 shows that there are clear correlations between the formation data and the weight on bit in this interval. The density of the formation starts to increase at approximately the same depth as where the weight on bit is increasing, causing the formation to be less porous and harder to drill. Through the rest of the interval of interest, the density of the formation is following the same trend as the drilling parameters. It can also be seen that the rate of penetration in general follows the same trend within the interval of interest. All of this are indications that the well is entering a harder formation with reduced drillability and that this can both be identified in the drilling parameters and in the formation data, meaning that there are correlations in the data.

8 Applicability of results

A higher weight on bit needed in order to achieve the same rate of penetration when drilling the same formation is interpreted to be an indication of bit wear. By analyzing drilling data and sub-surface data from Well A and Well B on the Edvard Grieg field, it was evident that these data could be used to indicate bit wear. This result can be used in the drilling industry to optimize the drilling process. By using high-telemetry drill pipe and downhole tools recording and transmitting high-resolution mechanical data, it is possible to monitor the drilling parameters at all times. Then if the drilling data show indications of bit wear according to the results given for Well A and Well B, actions can be made fast and the further drilling process can be evaluated in a more sophisticated way. In cases of indications of bit wear, the bit can be pulled earlier in order to achieve the desired rate of penetration and to optimize drilling to the target depth.

9 Conclusion

- Several different problems related to both the downhole environment and the drilling equipment are related to drilling hard and abrasive formations. Excessive bit wear are experienced when drilling such formations

- There are many factors affecting the rate of penetration. Several mathematical models have been developed to investigate the complex relation between them. These models can be used to determine the optimum drilling parameters in order to achieve the maximum rate of penetration and thereby minimize the drilling costs

- When comparing the same formations throughout the reservoir section for both Well A and Well B, an identical pattern was recognized. In sandstone, the average formation density is lower than in conglomerate and the weight on bit needed in order to achieve the same desired rate of penetration (30m/hr) is lower. Therefore, it is concluded that this pattern is typical for sandstone and conglomerate and that the results are applicable for other wells consisting of the same lithology

- After analyzing the given drilling data and formation data, it is concluded that the bit experienced more aggressive bit wear when drilling the conglomerate sections and that the resulting rate of penetration was significantly lower compared to sandstone

- Through the investigation of both wells it is be concluded that when the bit is worn, the weight on bit have to be increased in order to maintain the same rate of penetration when comparing the same formations. Since Well A and Well B are showing the same results, it is concluded that drilling data and formation characteristics are sufficient in order to investigate and determine bit wear according to this statement

- When comparing drilling data such as rate of penetration and weight on bit with formation characteristics from Well B, it is evident that there are clear correlations in the data given. Therefore, it is concluded that a combination of these can be used in the investigation of bit wear

- If the same patterns as the ones detected in Well A and B are recognized in a new well, decisions can be made faster and more sophisticated regarding when to pull the worn bit, which can potentially result in a higher overall rate of penetration and a more optimized drilling process

10 Improvements and further work

In the future, the industry should strive to optimize the way of drilling challenging conglomerate intervals, to extend the bit life. This will reduce drilling time and prevent pulling of the bit due to wear, which again will reduce the drilling costs. Analysis of preferably downhole drilling data should be performed in order to find a more effective way of drilling conglomerate.

Only one the wells investigated in this evaluation was drilled utilizing a tool to record downhole drilling data (CoPilot) in the BHA. In order to get a deeper understanding of the downhole environment, tools that record and transmit downhole drilling data should be standard for most drilling processes. This would be an improvement to the investigations since the increased friction forces in the extended borehole may be ignored.

Ideally, more wells than two should be evaluated in order to look for trends and patterns, but the results from the two wells evaluated are so evident that the conclusion is still based on these. Improvements to the result could be to investigate more wells and compare other lithologies than sandstone and conglomerate if this is present to see if the same trend is evident.

In this evaluation, the density of the formation is used as an indication of the formation hardness and the drillability. Ideally, the unconfined compressive strength, UCS could have been used. On the other hand, this is just a correlation for different formations, so in reality it is not certain that this would give better estimations.

11 Nomenclature

Abbreviation	Definition
BHA	Bottom-hole assembly
ECD	Equivalent circulating density
MD	Measured depth
MSE	Mechanical specific energy
MWD	Measure while drilling
PDC	Polycrystalline diamond compact
ROP	Rate of penetration
RPM	Rotations per minute
UCS	Unconfined compressive strength
WOB	Weight on bit

Parameter	Definition
A	Cross sectional area of the borehole
a_1-a_8	Constants, Bourgoyne & Young
A_b	Bit surface area
a-c	Dimensionless constants to be determined
a_c-c_c	Lithology constants
Ar_{abri}	Relative abrasiveness
A_s-b_s	Permeability constants
A_v	Ratio of jet velocity
B	Constant from linear regression

C	Constant to be determined
C_b	Cost of bit
C_m	Downhole motor cost
C_r	Fixed operation cost of the rig
D	Depth
d_{bit}	Bit diameter
d_{nozzle}	Nozzle diameter
E	Young's modulus
f_1-f_8	Functional relations, Bourgoyne & Young
$f_c(P_e)$	Chip hold down effect
F_j	Jet impact force
F_{jm}	Modified jet impact force
g_p	Pore pressure
h	Fractional bit tooth wear
K_1-K_2	Field dependent constants
P_e	Differential pressure
p_m	Maximum impact pressure
q	Flow rate
s	Distance from jet to impact point
S	Rock strength
T	Torque
t_c	Pipe connection time
t_r	Bit rotation time
t_t	Total trip time
$V_{fluid\ return}$	Velocity of fluid return
v_{nozzle}	Nozzle velocity
V_p	P-wave velocity
W_c	Bit wear coefficient

W_f	Wear function
$\left(\frac{WOB}{d_b}\right)_t$	Threshold bit weight
γ_f	Fluid specific gravity
ΔBG	Change in bit tooth wear
ΔD	Depth drilled
Δt	Interval transit time
ε_z	Axial strain
μ	Coefficient of sliding friction
μ	Plastic velocity
ρ	Fluid density
ρ_c	Mud weight
σ_z	Axial stress
φ	Porosity

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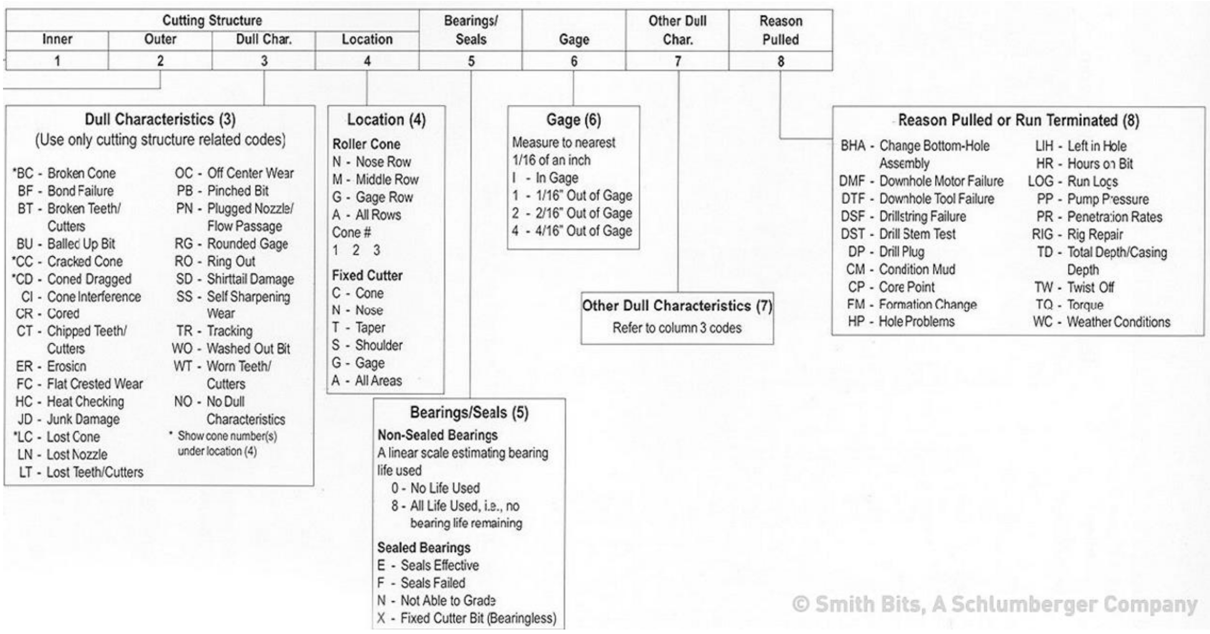
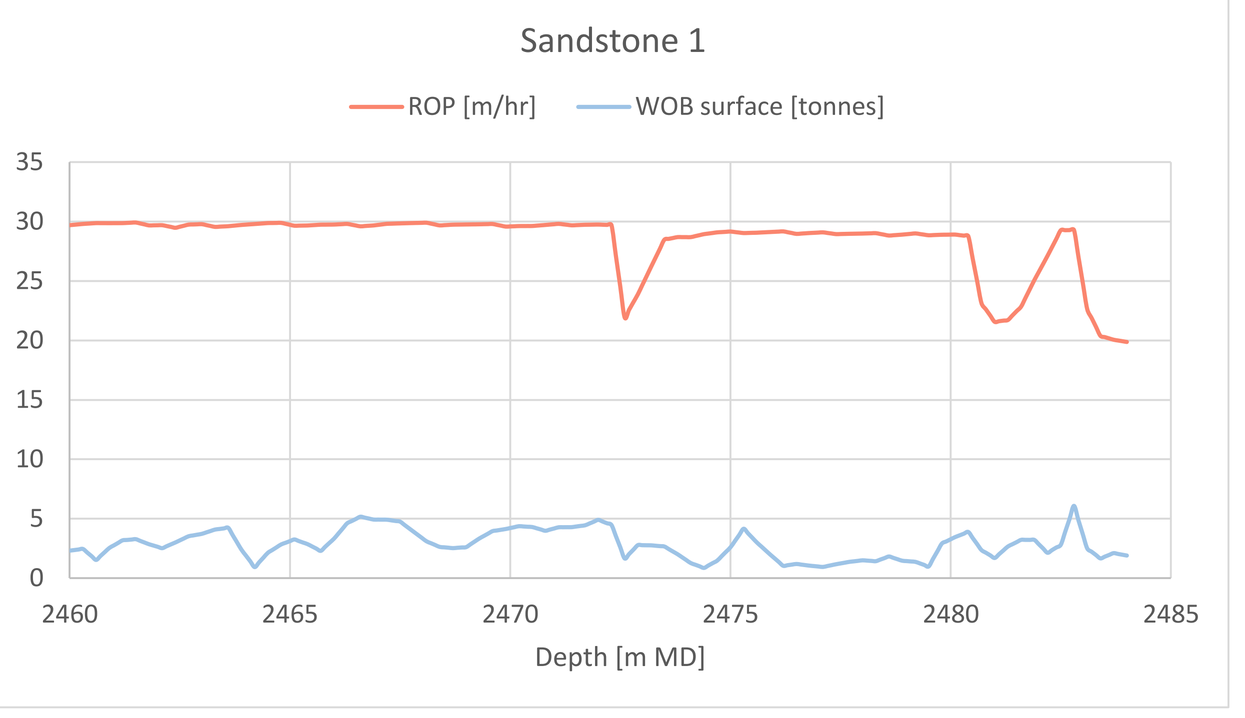
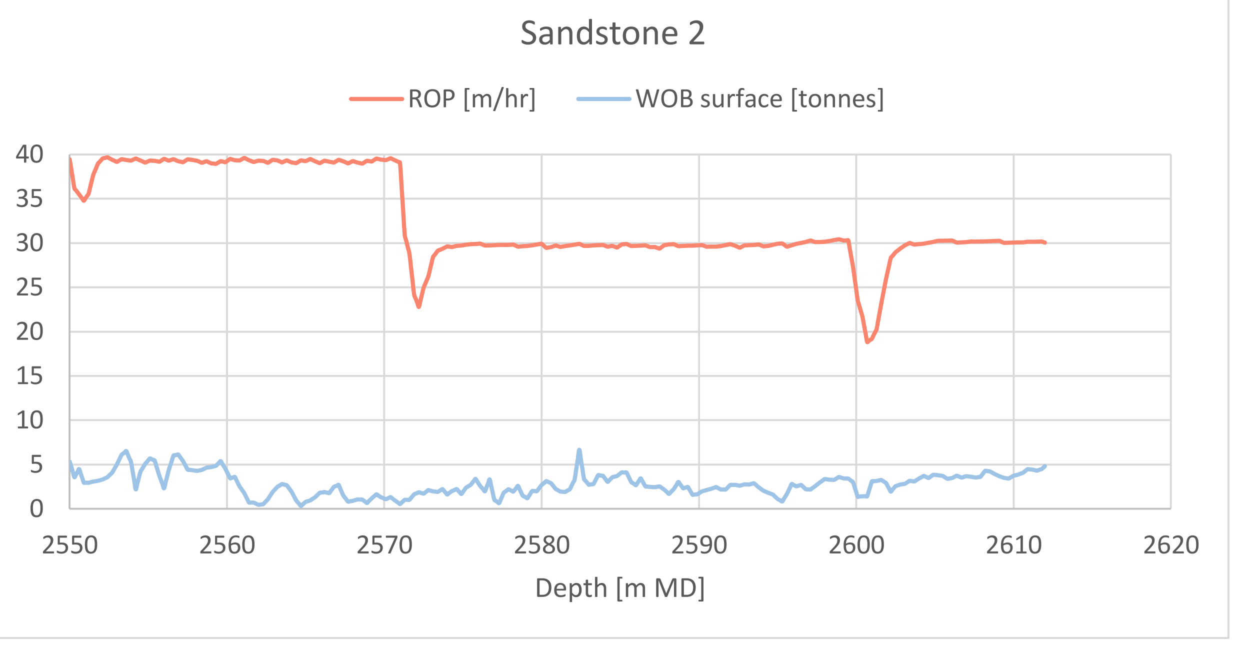
13 Appendix

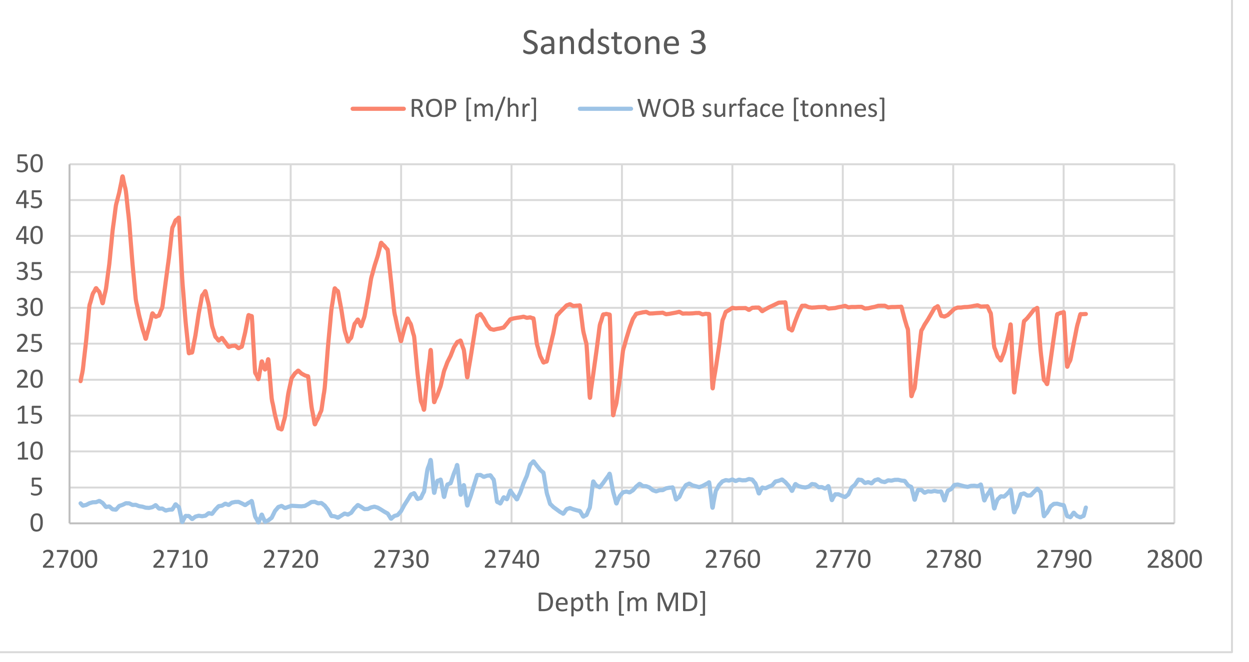
A. IADC Dull Grading



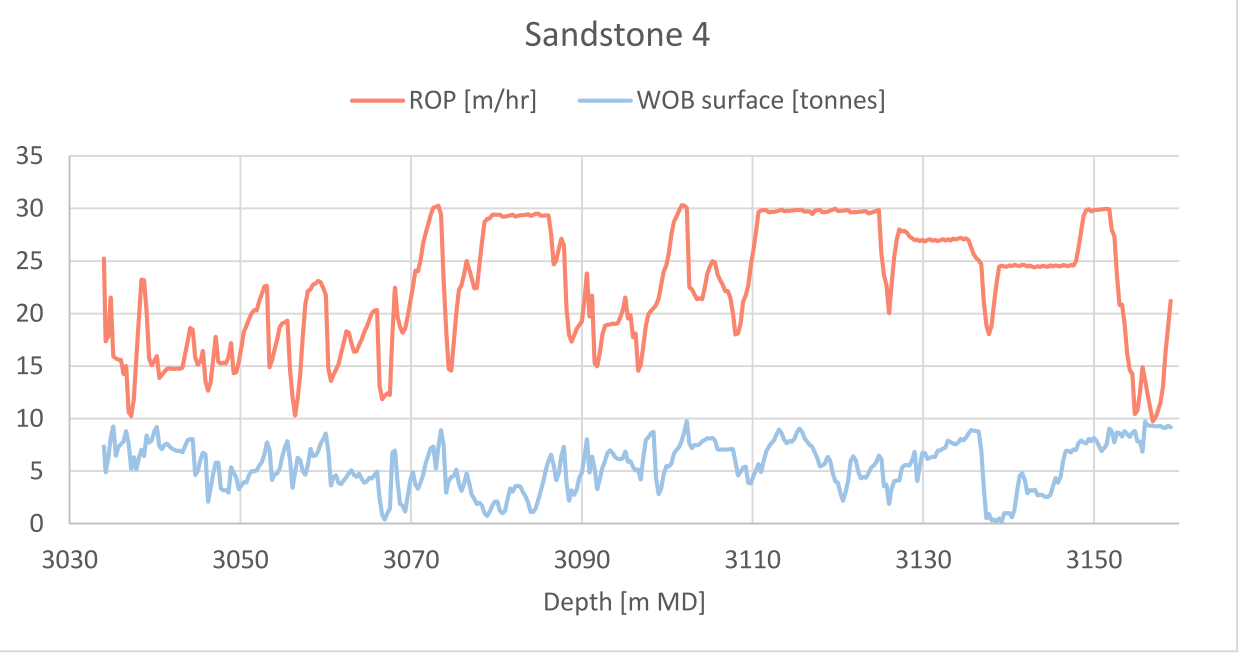
B. Detailed description of the sandstone sections Well A





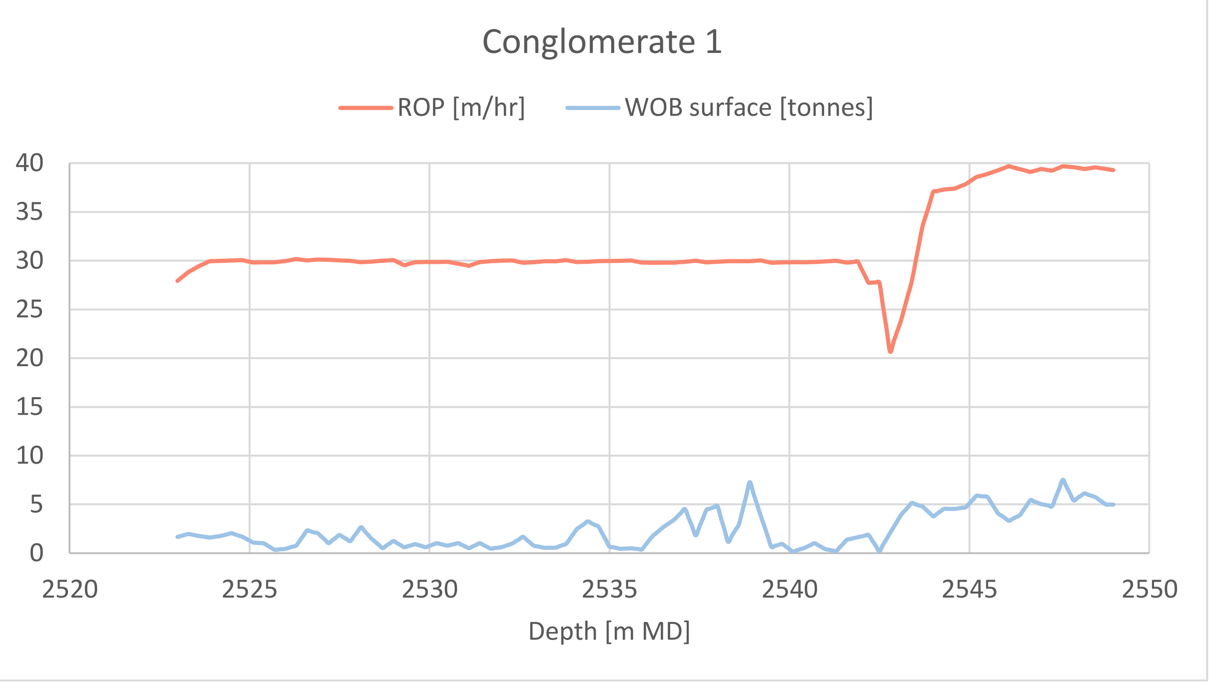


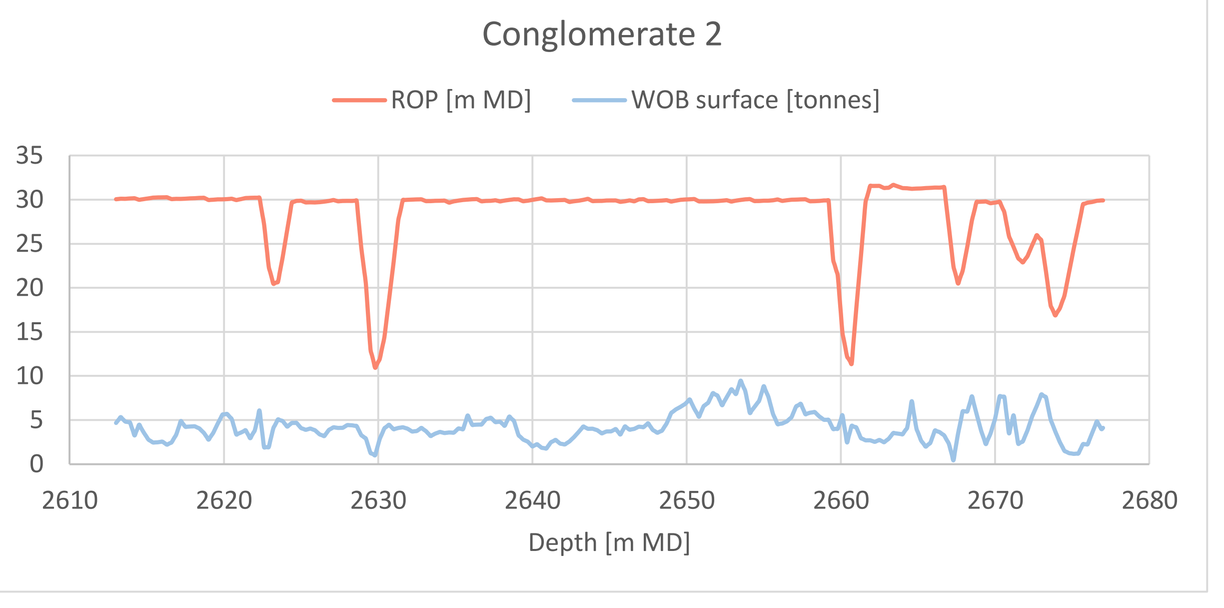
Sandstone 3
ROP [m/hr]
WOB surface [tonnes]
50
45
40
35
30
25
20
15
10
5
0
2700
2710
2720
2730
2740
2750
2760
2770
2780
2790
2800
Depth [m MD]

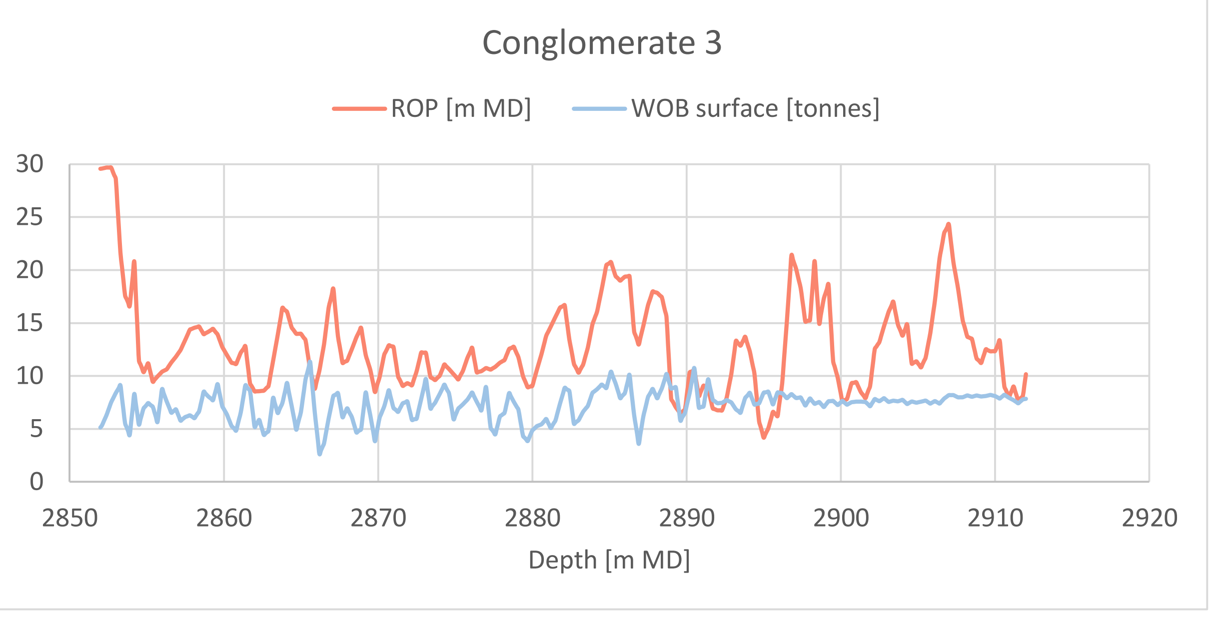


Sandstone 4
ROP [m/hr]
WOB surface [tonnes]
35
30
25
20
15
10
5
0
3030
3050
3070
3090
3110
3130
3150
Depth [m MD]

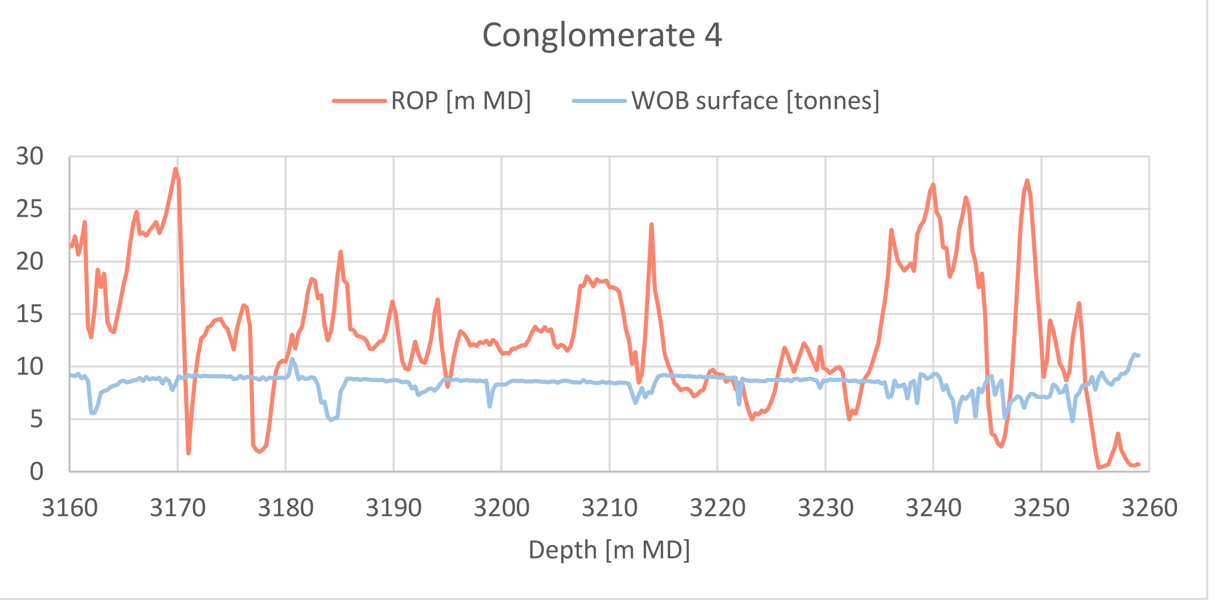
C. Detailed description of the conglomerate sections Well A





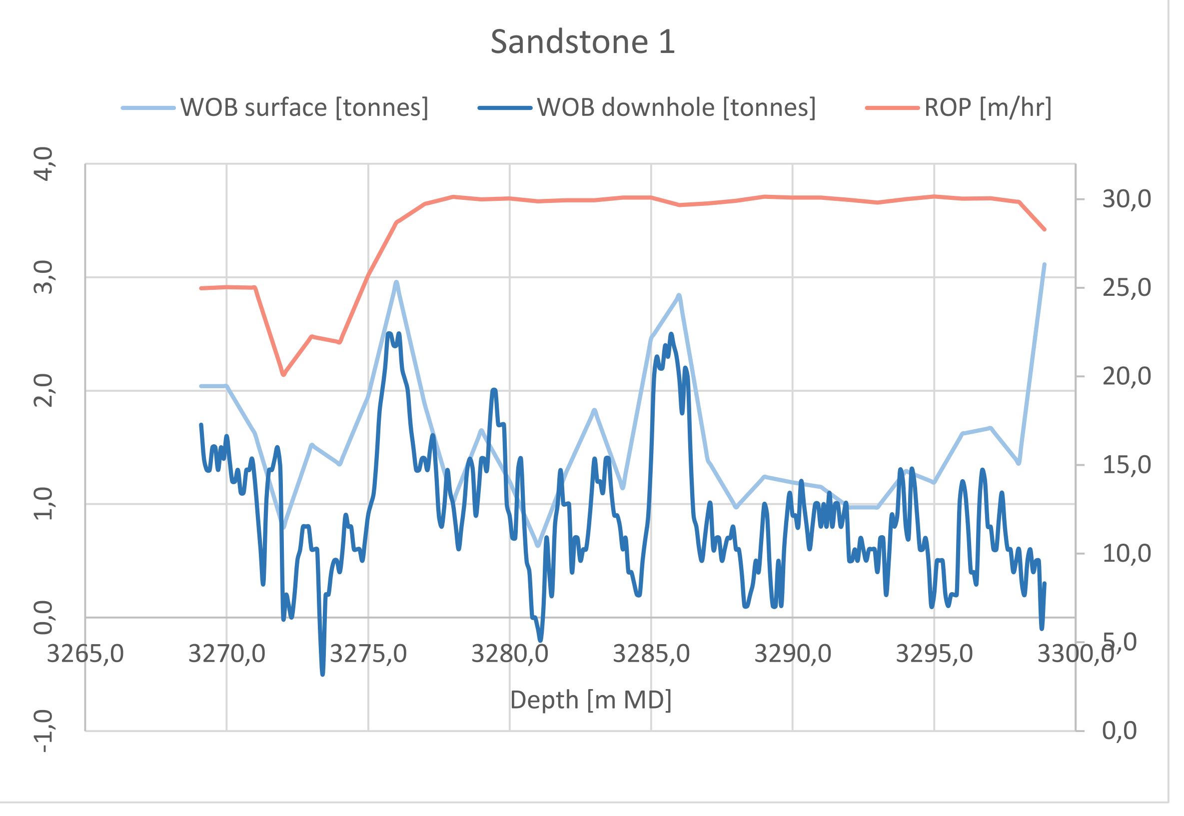


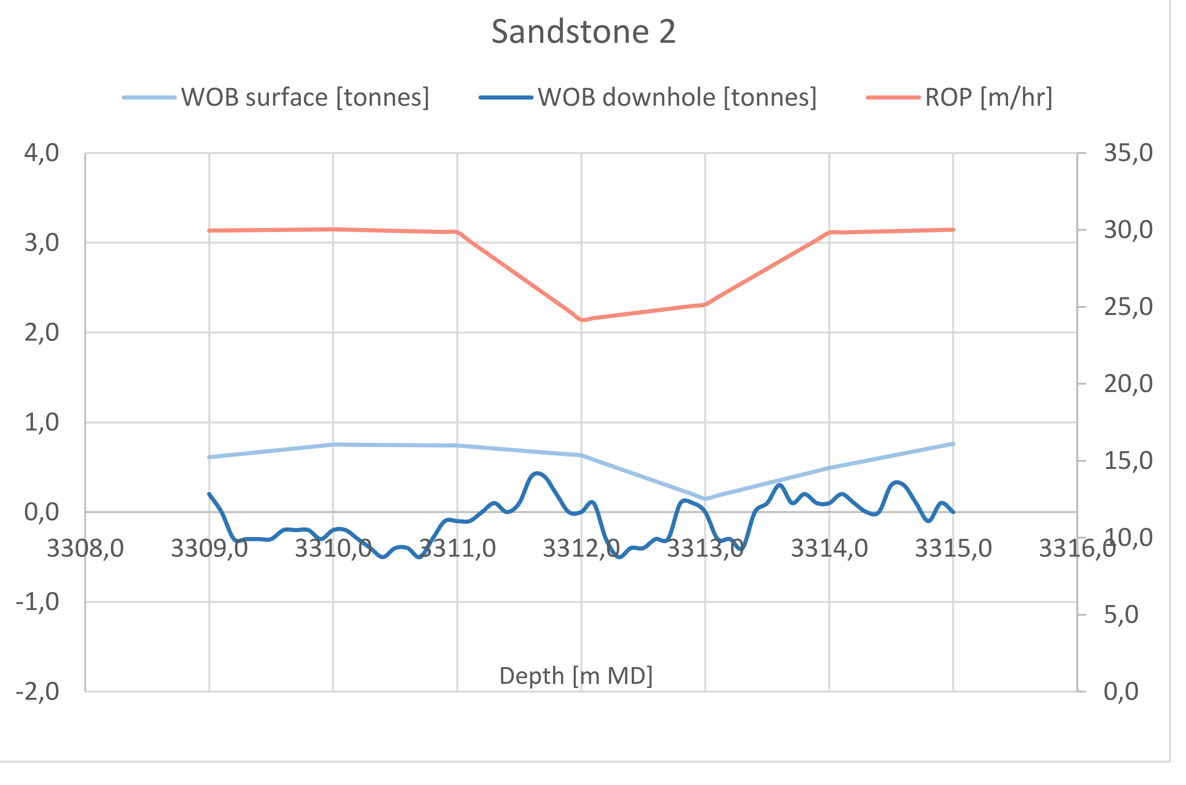
Conglomerate 3
ROP [m MD]
WOB surface [tonnes]
30
25
20
15
10
5
0
2850
2860
2870
2880
2890
2900
2910
2920
Depth [m MD]

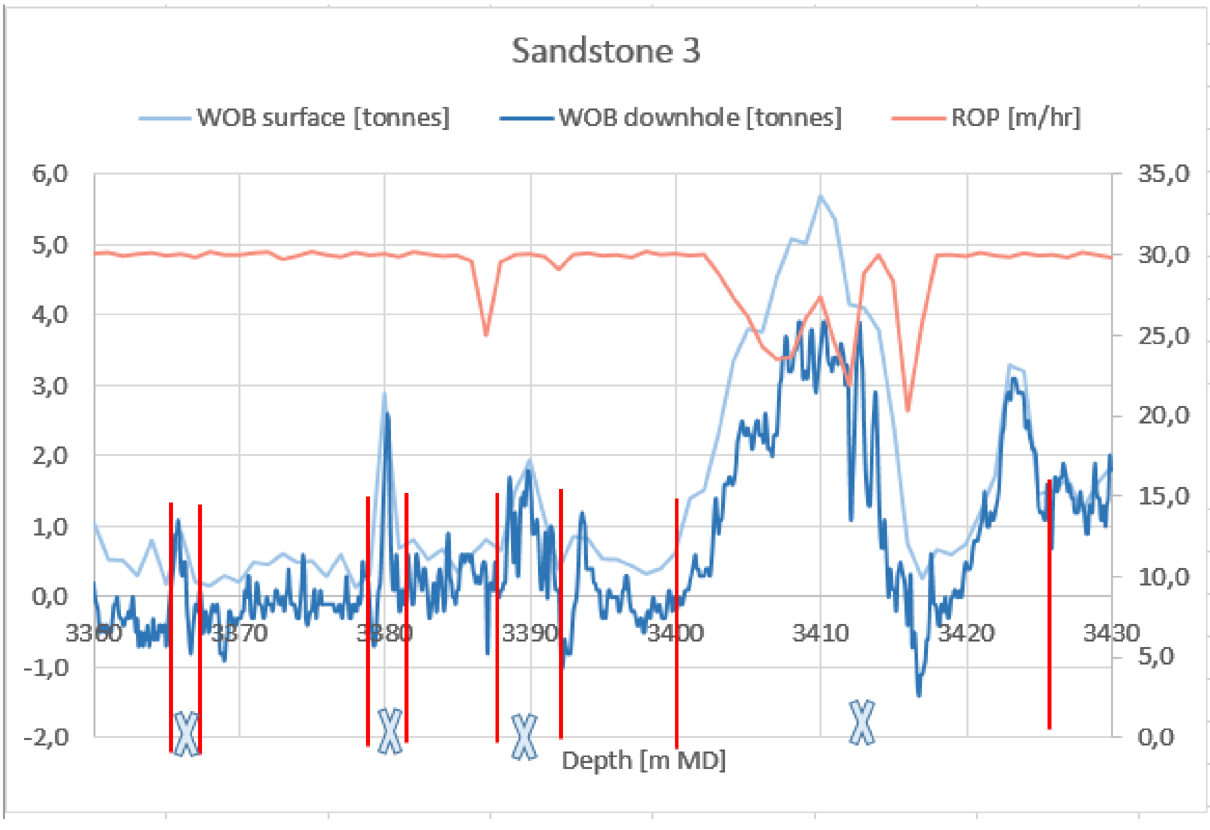


Conglomerate 4
ROP [m MD]
WOB surface [tonnes]
30
25
20
15
10
5
0
3160
3170
3180
3190
3200
3210
3220
3230
3240
3250
3260
Depth [m MD]

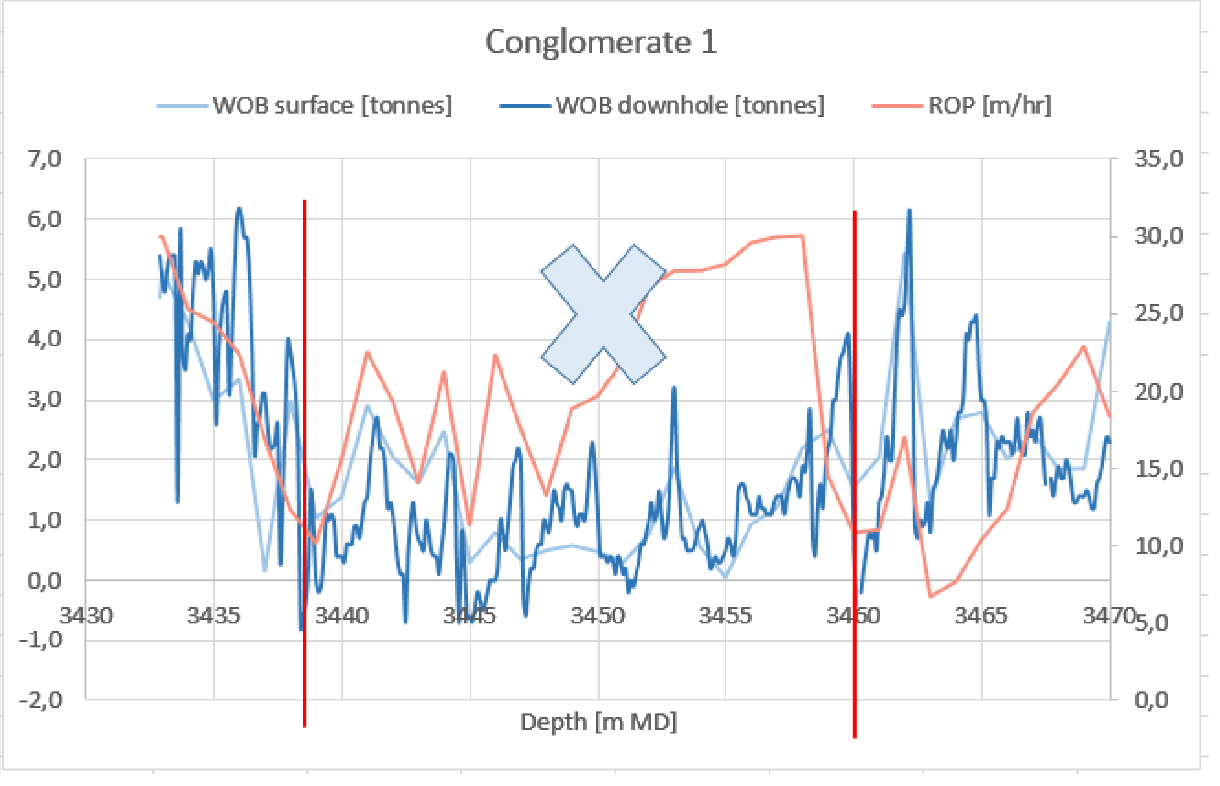
D. Detailed description of the sandstone sections Well B

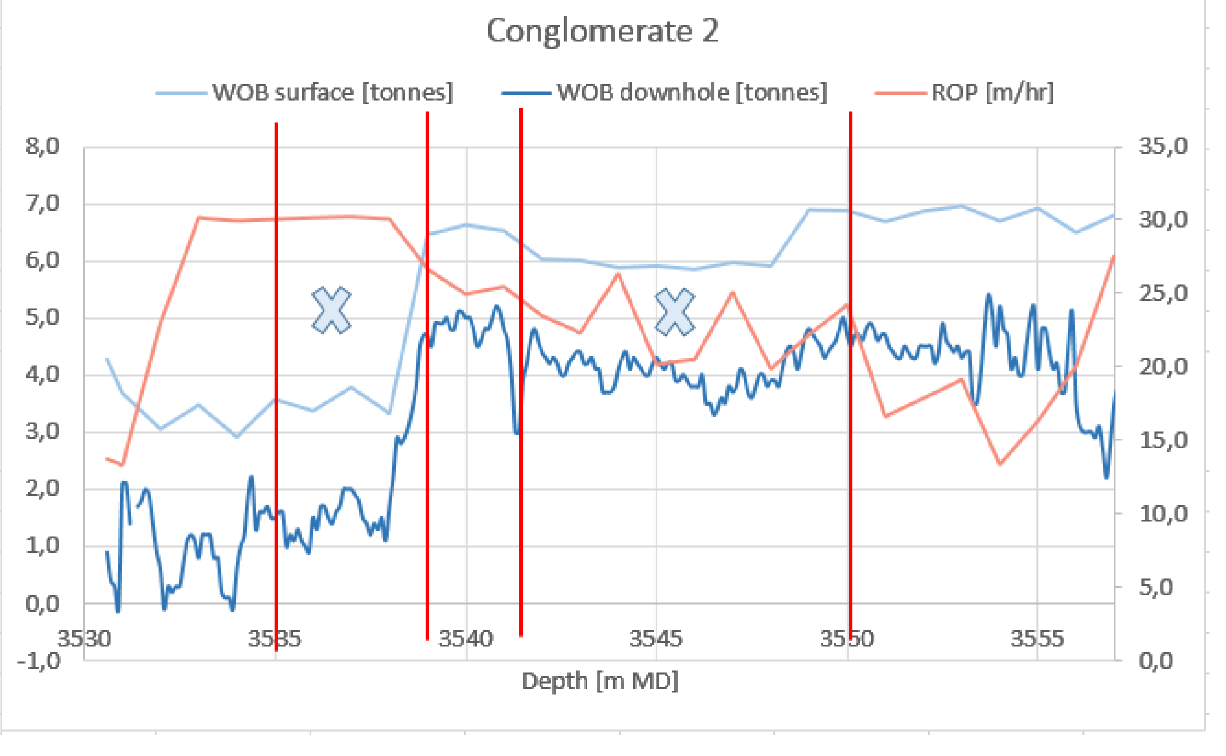


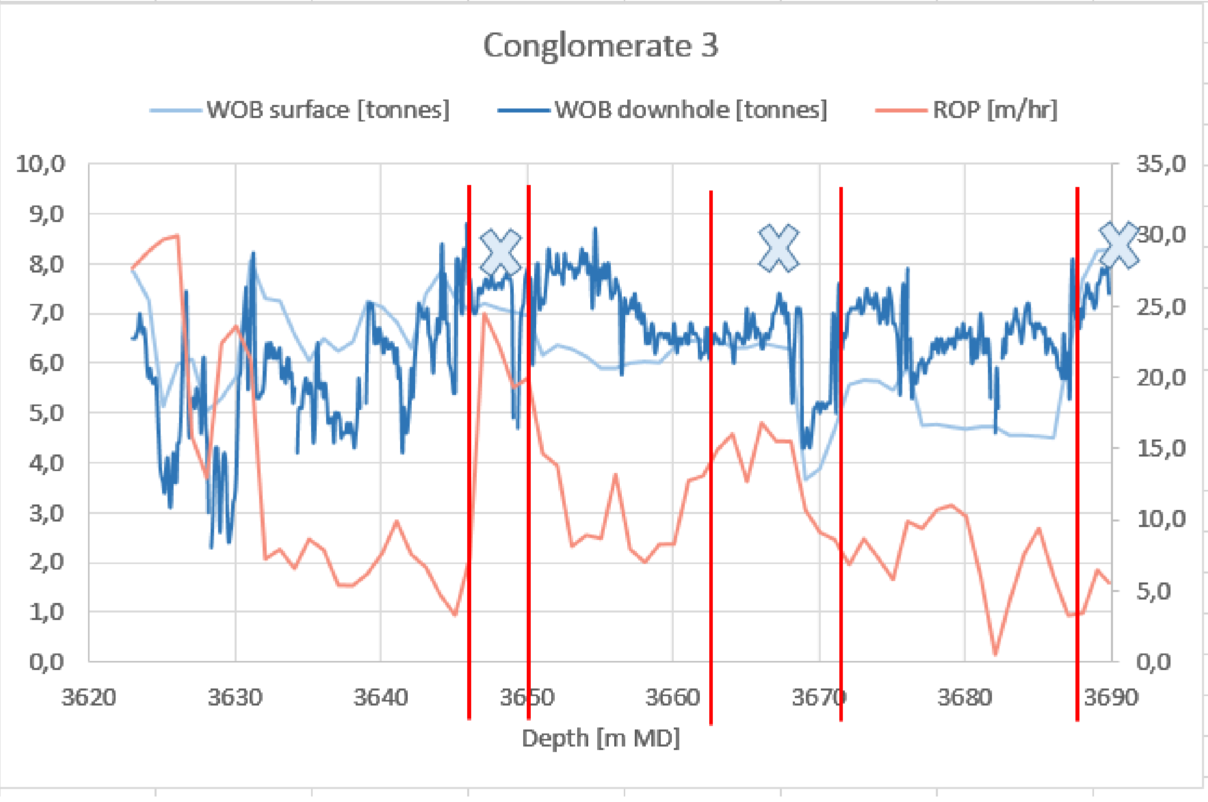



Sandstone 3
WOB surface [tonnes]
WOB downhole [tonnes]
ROP [m/hr]
6,0
5,0
4,0
3,0
2,0
1,0
0,0
-1,0
-2,0
35,0
30,0
25,0
20,0
15,0
10,0
5,0
0,0
3360
3370
3380
3390
3400
3410
3420
3430
Depth [m MD]

E. Detailed description of the conglomerate sections Well B






Conglomerate 3
WOB surface [tonnes]
WOB downhole [tonnes]
ROP [m/hr]
10,0
9,0
8,0
7,0
6,0
5,0
4,0
3,0
2,0
1,0
0,0
35,0
30,0
25,0
20,0
15,0
10,0
5,0
0,0
3620
3630
3640
3650
3660
3670
3680
3690
Depth [m MD]