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## Abstract

The well construction time and cost on the Norwegian Continental Shelf has increased drastically since 2001. The production is declining and there is a strong need to bring more wells on production while at the same time there is an increasing amount of development drilling scheduled for the upcoming years. The industry is in a time squeeze and it is crucial for future value generation on the Shelf to reduce the well construction time and cost.

It is claimed that Drilling Optimization services increase drilling efficiency, reduce NPT and failures. However, it is very difficult to measure the exact effect Drilling Optimization has on the drilling operations. This thesis aims to identify and in best case quantify “The Value of Drilling Optimization” in 8 carefully selected North Sea wells.

The work revealed that there was a clear improvement in drilling efficiency, but it was not possible to quantify the effect of drilling optimization. This was because the reported information did not allow the source of the improvements to be identified. An estimate of the value of the total improvements was generated based upon the difference in performance between the two batches the wells belonged to. The estimated value suggested that the improved drilling efficiency for a well designed as an average of the sample wells would reduce the drilling time with 2.54 days. The study also revealed valuable elements both with respect to the development of total drilling efficiency through the two batches and key elements related to the process of studying drilling performance. Some of the key findings were:

- The optimization often gets camouflaged by other events affecting the performance targets and the absence of an identifiable effect of drilling optimization measures on/in the performance targets, does not necessarily imply that they have not been present.
- Contract Incentives affects performance - Increased performance does not come for free and needs to be encouraged through contract incentives that impact all parties involved.
- Real value is generated when all parties involved are working together while using their best of knowledge and ability to reach the required targets. Communication, feedback, consistency and cooperation are vital ingredients in such an approach.

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## Abbreviations

WOB – Weight On Bit

BHA – Bottom Hole Assembly

DO – Drilling Optimization

RPM – Revolutions Per Minute

ROP – Rate Of Penetration

POOH – Pull Out Of Hole

DP – Drillpipe

DS – Drillstring

BHP – Bore Hole Pressure

PP – Pore Pressure

FP – Fracture Pressure

MODU – Mobile Drilling Unit

OBM – Oil Based Mud

WBM – Water Based Mud

BOP – Blow Out Preventer

MD – Measured Depth

TD – Target depth

TVD – True vertical depth

PWD – Pressure While Drilling

FTWD – Formation-Pressure While Drilling

MWD – Measurements While Drilling

LWD – Logging While Drilling

SWD – Seismic While Drilling

GR – Gamma Ray Sensor

RES – Resistivity Sensor

DIR – Directional measurement sensor –  
Provide Surveys: Measures the magnetic and  
gravity field in X, Y and Z directions and  
supply a total value.

DEN – Density sensor

NP – Neutron Porosity

DDS – Drillstring Dynamics Sensor –  
vibration sensor

MW – Mud Weight

PDC – Polycrystalline Diamond Compact

RKB – Rotary Kelly Bushing

3D RSS – Rotary Steerable System

HPHT – High Pressure High Temperature  
(>690bar, >150 deg Celsius or deeper than  
4000 m)

NBG – Near Bit Gamma sensor

WOW – Wait On Weather

B/U – Bottoms Up (Refers to when one  
annular volume I circulated)

TT – Trip Tank

# 1. Introduction

Drilling optimization have developed from being related to conceptual optimization as the rotary drilling principle and the use of drilling mud in the 1920's, full automation of rig and mud handling in 1967 to the application of the first scientific techniques [3]. The same techniques that make up the fundamental base for what Drilling Optimization is today. In 2004 David C-K Chen defines drilling optimization as:

*“Drilling optimization is a process that employs downhole and surface sensors, computer software, Measurements While Drilling (MWD) and experienced expert personnel – all dedicated to reduce drilling trouble time and increase drilling efficiency” [4].*

As the cost of lifting oil is growing, it is important to increase the drilling efficiency and reduce well construction time. A study of drilling in shallow water shelf in the Gulf of Mexico shows that troubled time accounts for 25% of rig time. In dollar terms, it is about 1.5 million USD per well [2]. Hence, a small reduction in trouble time and increased drilling efficiency can result in tremendous time and cost savings. On the Norwegian Continental shelf there is in addition to the continuous battle to reduce trouble time a time squeeze developing. The number of wells needed on existing fields is accumulating while at the same time operators have set high goals within development drilling [10]. For further successful value creation on the NCS, It is vital to increase the drilling efficiency and reduce well construction time.

It is claimed that Drilling Optimization services increase ROP, reduce NPT and failures. However, it is very difficult to measure the exact effect Drilling Optimization has on the drilling operations. This thesis aims to study the effect Drilling Optimization has on the drilling efficiency and time usage, and at best quantify the value of this effect. This is done by comparing the performance in 8 carefully selected North Sea wells with same fundamental technical, geotechnical and Drilling optimization service base.

Information on the measures and services that were supplied to the operator in the planning, Real-Time and post phase of the drilling operations are described.

The wells are analyzed in terms of the Below Rotary Table, operational, circulation and drilling hours that were spent in each hole section. In addition the Rate of Penetration and Non Productive time is evaluated. The drilling efficiency in each hole section is studied in chronologically order from when the wells were drilled, and the result evaluated and discussed in terms of the information provided by the End Of Well Reports.

An average well is designed as an average design of the wells used in the study. The average well provides the fundament for an estimation of the value of the total improvement in terms of time and money. Further, the contract set-up that governs the drilling service providers' revenue generation is discussed in relation to performance. Finally a summary of the findings from the discussion and results are given in relation to the general situation the operators on the Norwegian Continental Shelf are facing before a conclusion is presented.

## 2. Background

### 2.1. Status on the NCS – Norwegian Continental Shelf

Over 40 years ago the first Norwegian oilfield started up production. Since then, the Ekofisk field has seen over 40 Years of production and have started restructuring for another 40 years. Several large Norwegian oilfields have been brought online, since then; Statfjord, Gullfaks, Draugen, Troll, Ormen lange and Snøhvit to name a few. The NCS also still delivers in exploration, with the newly discovered elephant Aldous Major – Avaldsnes, now known as Johan Sverdrup, as the latest example [5]

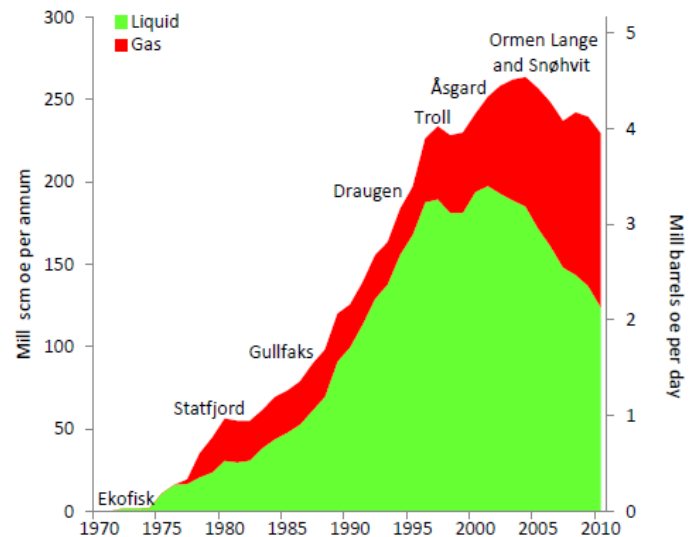


Figure 1 - Historical production on NCS from 1970 to 2010 [5]

Norway is still a large exporter of oil and gas and was in 2011 the 7<sup>th</sup> largest oil exporter and second largest gas exporter in the world [6]. Figure 1 shows that the oil production peaked in 2001 and an increasing fraction of our production is now coming from gas. The gas production is still increasing but not sufficient to keep the total production level. Figure 2 shows the estimated future production on the NCS. The majority of the future production is to come from reserves in existing fields but the resources in new fields and discoveries are also expected to bring a significant portion. Figure 3 is based on data provided by the licensees on the NCS. It shows the amount of resources in producing fields and what technologies and methods they are expecting to realize these resources [11].



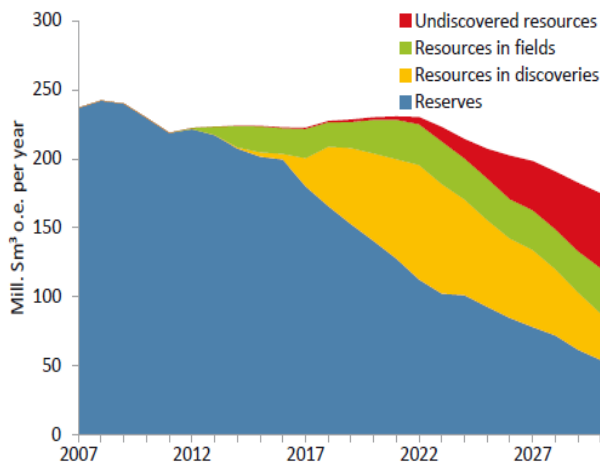


Figure 2 - Production forecast and source until 2030 [7]

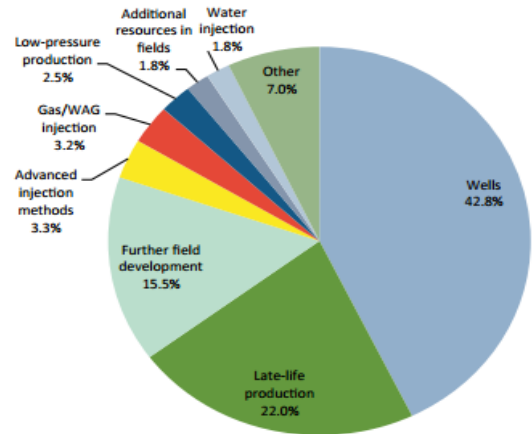


Figure 3 - Reported resources in plans and methods for reserve growth in producing fields [8]

The highest single impact factor for future production on existing fields is expected to be drilling of new well's. However, the number of wells being drilled from fixed installations (Figure 5) is actually less than planned. The residual wells from each year are postponed to next year along with their production. This causes an accumulation of the number of planned wells to be drilled, while at the same time the number of wells needed per year increases (Figure 6).

The average well construction cost has more than doubled from year 2003 to 2009 (figure 4). In the MODU market there is limited rig availability and contracts for MODU for drilling in 2013/14 started signing already in March 2012 [9]. One of the reasons for the increased demand for rigs the latest years is that MODUs are being used in the continuously increasing amount of intervention and workover operations that need to be performed [1]. The large number of future Permanent Plug & Abandonment (PP&A) campaigns is also expected to increase the pressure in the rig market.

The number of platform wells required per year is increasing and the MODU rig rates have increased significantly. This has made the operational time usage the most critical optimization factor in the well construction process. The operator companies are also fully aware of this and it takes us into the subject Technical limits and Key Performance Indicators KPI's.

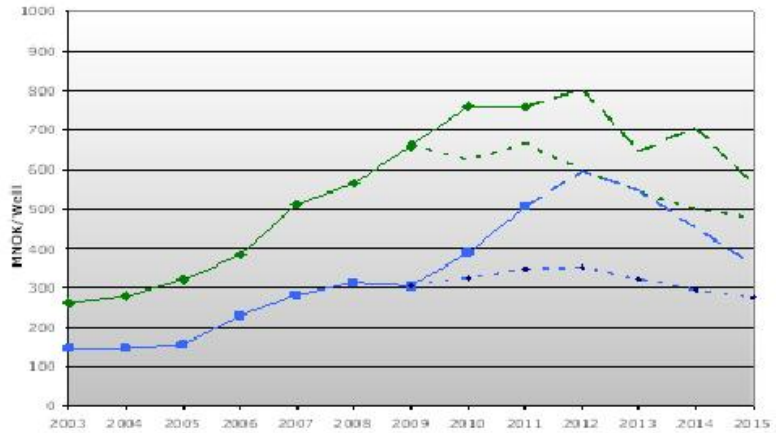


Figure 4 - Historical and estimated development of well costs from 2003 – 2015 for 8 fields on the NCS. The green curve for MODU and blue for fixed installations [1]

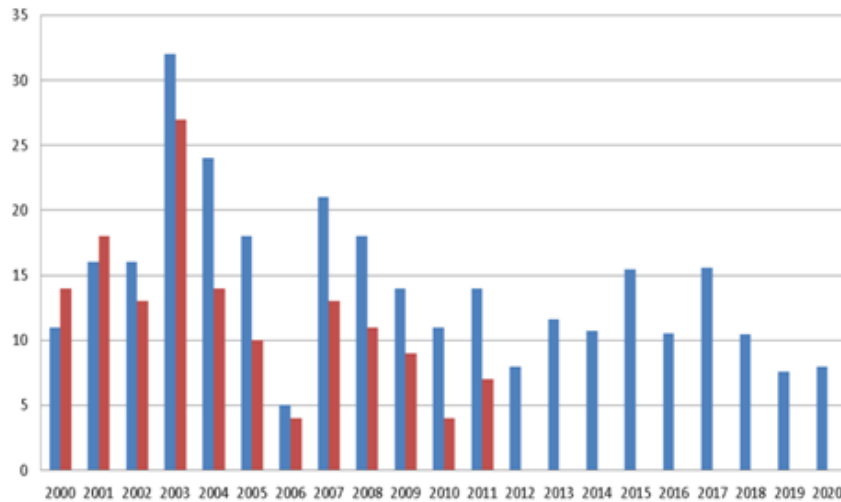


Figure 5 - The historical development of the planned versus the actual wells drilled from fixed installations on some of the larger field on the NCS. Blue bars showing planned and red bar showing the actual wells drilled per year

[1]

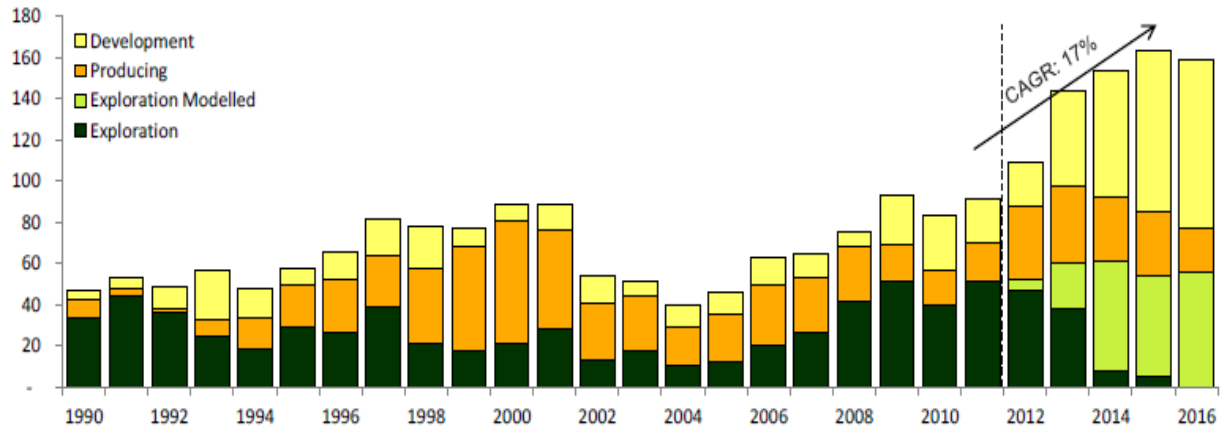


Figure 6 - Historical and future number of wells drilled excluding sidetracks on the NCS from 1990 to 2016 sorted by well type

[10]

## 2.2. Technical Limit

Technical limit is defined as the best possible well construction performance for a given set of design parameters. The Technical limit approach is based upon the time used to construct a theoretical well where all operations are carried out without any flaws and without any improvement potential. This is done by;

- Selecting a set of appropriate reference wells
- Dividing the well construction process into sequences
- Quantify the time used in each sequence or section

The “best in class” time usage in each section / operation of the reference wells is added up to generate the total time used to drill the Theoretical well. As an analog, The Technical limit/theoretical well is kind of aiming to set the world record or at least regional record in all ten aspects of a decathlon. Removable time is defined as the difference between the actual well duration and the technical limit time. Removable time is then divided into conventional lost or down time and invisible lost time. Invisible time being the classification of the activities that one would include in a normal well, like; wiper trips, mid-section bit change or BHA trips, reaming etc.

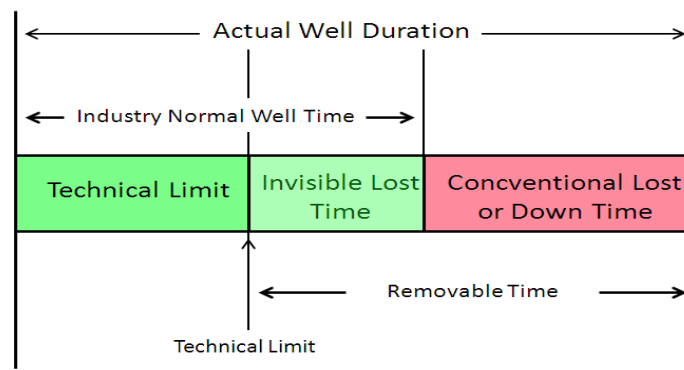


Figure 7 - Schematic showing the relationship between: Technical Limit, Invisible Lost Time, Conventional Lost or Down Time, Actual well duration and the industry normal well time [12].

The philosophy is to identify the technical shortcomings and thereby develop improvements in terms of actions or changes rather than accepting the shortcomings as factors that always is going to be present, even if this is the case. One will most likely never reach the technical limit but through your actions you will need to implement measures that will take you closer than you have been [12].

Different operators apply different visions of the technical limit methodology but their main objectives is still the same: To make the hours and cost needed to drill a well as low as possible.

Regardless of if one is using the concept of the technical limit or some variant of this methodology there are some indisputable elements that will have a critical influence on the total well construction time. These are related to:

1. **The efficiency of the rig and drill crew** – How fast the rig and drilling crew are able to do standard operations related to the drilling operation. Normal Key Performance indicators related to this are: Casing/liner running speed, Connection time, tripping speed. They are vital operations that are repeated continuously through the well construction process and a large contribution to the total time usage [14].
2. **Equipment reliability** – Non Productive Time (NPT) caused by equipment failure. This may be vital surface equipment like mudpumps, topdrive, pipe handling equipment or downhole tools such as M/LWD tools in the BHA. They all have in common that their failure will either halt the drilling operation or cause an unintended trip out – trip in operation. Depending on the depth and the length of the well section it is not unusual that it takes 24 hrs before one can start drilling again. For M/LWD equipment this reliability is typically measured through the KPI: Mean Time Between Failure (MTBF). MTBF is the number of BHA component failures in a run, a section or a well divided on the operational, circulation, drilling or Below Rotary Table hours of the run/section/well [13].

3. **Formation Related add-on factors** – Additional operations or failures caused by the downhole environment that directly or indirectly slows down or increases the time needed to construct the well, collectively known as Drilling Challenges.

## 2.3. Drilling challenges - Direct and Indirect contributors

### 2.3.1. Vibration

Vibrations are the result of interactions between the bit and the formation under certain frequency's and conditions [16]. During the rotation of the drillstring (DS), mechanisms such as mass imbalance, misalignment, bent pipe or drillstring walkabout may cause excitations at the same or multiples of the same frequency as the rotational frequency [15]. These mechanisms may create forces and stresses that oscillate at the same frequency as the excitation mechanism. If these oscillations match the BHA or drillstrings own natural frequency, known as the critical speed, a resonance condition with growing stress in the BHA / DS is generated [17].

#### 2.3.1.1. Vibration Mechanisms

*The main content of this section on vibration mechanisms is taken from: Halliburton – Sperry Drilling, ADT Drilling Optimization Brochure, 2010: Drillstring Integrity Service -Vibration Sensors and Vibration Mitigation Guidelines. Other sources are listed with normal referencing.*

##### Stick-Slip – Torsional vibrations

Periodic acceleration and deceleration of the bit and Drillstring is triggered by frictional torque on bit and BHA and is the main cause of torsional vibrations. Low torsional stiffness of the drillstring, fluctuating downhole RPM, along with friction along string and at bit, causes a Non-uniform drillstring rotation in which the bits stops momentarily at regular intervals. This causes

the string to periodically torque up and spin free with RPM's that may be as large as 3 to 15 times surface average RPM [22]. Stick-slip is typically encountered in high angle and deep wells, when encountering hard formations or salt or when using aggressive PDC bits in combination with large WOB. Observable stick-slip effects are:

- More than 15% fluctuation in the average surface torque readings
- Damaged PDC Bit's
- Reduced ROP
- Connection over-torque
- Back-off and Drillstring spin-off's
- Mud Pulse telemetry detection problems
- Wear on stabilizers and Bit gauge

#### Bit Bounce – axial vibrations

In this mode large WOB fluctuation introduces an axial vibration that causes the bit to repeatedly lift of bottom, drop and impact the formation [19]. Bit Bounce it is often observed when drilling with tricone bit's that have unstable cutting patterns, in under gauge holes, through ledges and stringers, and generally in hard formations. The axial motion damages the bit cutting structure, seals and bearings. Topdrive and hoisting equipment may start to shake axially and if severe enough, lateral BHA vibrations may be introduced.

#### Bit Whirl – lateral vibrations

Lateral vibrations or walk of the bit is the eccentric rotation of the bit about a point that is not its geometric center. It is caused by PDC bit – wellbore gearing from having excessive side-cutting force. As a result the bit cut's itself a hole larger than its own diameter and is thereby allowed to walk around the hole, opposed to be rotating around its natural center. This vibration mode can't be seen on surface since the lateral vibrations are dampened throughout the string before it reaches the top [18]. Bit whirl can be seen when excessive side-cutting bits have been used or

when encountering soft and unconsolidated formations. The primary consequence of bit whirl is the damage it causes to the bit cutting structure. During the whirling motion the bit cutters are moving faster and are subjected to high impact loads. The high loads cause the cutters to chip thereby making the wear from abrasion and heat more prominent. The over gauge hole created by the bit whirling facilitate a downhole conditions that easily may cause the onset of BHA whirl.

### Backward & Forward BHA Whirl

Similar to the bit Whirl, BHA whirl is the eccentric rotation of the BHA about a point other than its geometric centre. The motion of the BHA is the same as described for bit whirl with both forward and backward whirling motions occurring. BHA whirl is a complex motion of the BHA generating lateral displacements, shocks and increased friction against the well bore wall. BHA whirl is onset as a consequence of bit whirl, rotation of a drillstring in imbalance or by the lateral movement induced from bit bounce. The consequences may be:

- MWD / directional equipment failure
- Localized tool joint and stabilizer wear
- Washouts
- Twist-off's due to fatigue crack's of connection(s)
- Increased average torque

### Torsional Resonance

More specifically this is drill collar torsional resonance, as this mode is related to the natural torsional frequency of the drill collars and is the consequence of the drill collars being excited. This very specific type of vibration is encountered when drilling in very hard rock's with PDC bits. This vibration mode is most damaging at higher rotational speeds. This is because at higher rotational speeds, higher amplitude resonance at the harmonics of the drill collar's natural frequency may occur. In some cases this high amplitude fluctuations may cause backward turning of the bit, damaged cutters as well as severe damage to downhole electronics.



### Parametric Resonance

Parametric resonance is severe lateral vibrations caused by the dynamic component of axial load. The dynamic component is primarily caused by bit – formation interactions and results in WOB fluctuations [23]. These fluctuations generate a mechanical instability that is evident through rapidly growing lateral vibrations at a specific frequency. As an analog the mechanism behaves the same way as you would see if you induce a snakelike motion in the end of a hanging rope by moving the end up and down at a specific frequency. This may generate severe lateral vibrations than may accelerate drillstring failure or create the opportunity of hole enlargement which in turn may cause poor directional control and onset of whirl. When Parametric Resonance is encountered it typically is in relation with interbedded formations and undergauge holes.

### Bit Chatter

Bit chatter is caused by the individual teeth of the bit impacting the rock. It is usually a low-level vibration with high frequency, 50 – 350 Hz, depending on the rotational speed and the number of bit teeth. Typical environment for this vibration mode is when using PDC bits in high comprehensive strength formations when the bit teeth have lost its shearing cutting action and the individual cutters are impacted on the formation. This results in cutter damage and high frequency vibrations as well as a bit dysfunction that may cause bit whirl.

### Modal Coupling

Modal coupling is when all the modes: axial, torsional and lateral are coupled together and there are vibrations in all three directions simultaneously [19].

This is the most severe mode of vibration. It generates axial and torsional oscillations along the BHA and large lateral shocks. It is usually onset due to the failure of controlling one of the vibration modes thereby allowing it to initiate one or more other mechanisms simultaneously. Environments where stick-slip, whirl or bounce can be initiated are typical modal coupling environments and consequences are typically: Measurements While Drilling (MWD) component

failures such as motor/3D RSS, M/LWD tool, localized tool joint and/or stabilizer wear, washout or twist-offs due to connection fatigue cracks and increased average torque.

Vibration Mechanism	Mode of vibration	Frequency	Real-Time Indications
<b>Bit Bounce</b>	Axial	1 - 10 Hz	- Shaking of surface equipment at shallow depths - Large WOB fluctuations - Possible SPP Fluctuations - Loss of tool face, poor directional control - Reduced or erratic ROP
<b>Stick-Slip</b>	Torsional	0.1 - 5 Hz	- Cyclic torque and RPM Rotary drive stalling - Loss of tool face, poor directional control - Reduced or erratic ROP - Interference with mud pulse, telemetry — signal loss
<b>Bit Whirl</b> <b>BHA Forwards Whirl</b> <b>BHA Backwards Whirl</b>	Lateral / Torsional	10 - 50 Hz 5 - 20 Hz 5 - 20 Hz	- Increase in mean torque - Loss of tool face, poor directional control - Reduced or erratic ROP
<b>Lateral Shocks</b>	Lateral	Irregular Impact	- Possible increase in mean torque - Possible associated torsional vibration — cyclic RPM and TRQ
<b>Torsional Resonance</b>	Torsional	20 - 350 Hz	- Possible increase in mean torque
<b>Parametric Resonance</b>	Axial / Lateral	0.1 - 10 Hz	- Possible increase in mean torque
<b>Bit Chatter</b>	Lateral / Torsional	20 - 250 Hz	- No surface indications
<b>Modula Coupling</b>	Lateral / Torsional and Axial	0.1 - 20 Hz	- Increase in mean torque - Loss of tool face, poor directional control - Reduced or erratic ROP - Interference with mud pulse, telemetry — signal loss

Table 1 - Frequency domain and Real-Time surface indicators for the different vibration mechanisms [21]

### 2.3.1.2. Vibration consequences

Vibrations will always be present but when severe enough they introduce a variety of direct and indirect negative effects. Some of the most severe are:

- **BHA Washouts**
- **Twistoff's**
- **Premature bit and drillstring failure**
- **Accelerated Failure of downhole equipment**

- **Excessive wear on tool joints**
- **Damage to topdrive and hoisting equipment**
- **Reduced ROP**
- **Hole Enlargement**

These events will further cause reduced equipment efficiency, increased repair and maintenance costs, additional trip's to change equipment, fishing operations or unstable hole conditions [18, 19]. They are all adding a significant time and cost of the total well construction for the operator company, the drilling service provider as well as the drilling contractor.

### **2.3.1.3. Mitigating Downhole Vibrations**

Mitigation of vibrations starts already in the planning phase where one attempt to design out vibrations as best possible. This is done by doing BHA simulations on critical rotary speeds and based on this optimizing the BHA design. Force, load and critical rotary speed analysis are carried out. Real-Time (RT)-modeling of RPM, WOB and vibrations allows for the avoidance of critical rotary speeds [24].

The mitigation strategy while drilling is: detect vibration – determine the mode / vibration mechanism – apply corrective action to operational parameters; RPM and / or WOB. To do this effectively one needs to monitor downhole vibrations. This is done by using e.g. a Drillstring Dynamics Sensor – DDS in the BHA that gives you average, peak and burst (instantaneous) vibration readings along all three axis's [21].

### 2.3.2. Borehole instability

Different formations have different properties and when we are drilling we are interfering with both the geochemical and the geomechanical equilibrium in the rock. In practice this means that the wellbore wall and downhole conditions will respond and change due to the disturbance.

Dependent on the formation properties this will be reflected in a diversity of undesirable scenarios:

- Naturally fractured formations, fractured formations close to a large fault, rocks with strong in-situ stress field or simply a mechanical failure of the borehole wall causes chips, chunks or boulders to fall into the well.
- Temperature changes may cause instability in the rock which further causes it to fracture and collapse into the wellbore.
- Some formations, like salt may behave plastically and slowly creep into the wellbore eventually close around the string.
- Sands may be unconsolidated and collapse into the wellbore
- Shale's may be geo-pressured and to a certain degree exhibit the same behavior as salt
- Shale's may also be reactive and form sticky mud balls known as gumbo clay that stick to its surrounding
- Breakage or softening of rocks due to interactions with the drilling fluid.

These events cause additional operations; reduced drilling efficiency and cause well control issues. Fractured and collapsed material may pack around the drilling assembly resulting in twistoff, increased torque and drag, packoff, stuck pipe, lost drilling assemblies and sidetracks. More material in the annulus may cause increased ECD and Packoff's, causing lost circulation events to further induce a kick. The wellbore wall may become severely overgauge, making LWD measurements inaccurate, cementing operations challenging, challenge directional control as well facilitate the onset of certain vibration modes. Undergauge hole makes the clearance to the wall smaller, reduces the surge free tripping speed when running casing, in worst case

making it impossible to get the casing string down at all. The picture in Figure 8 shows some of the scenarios described [20, 25, 30, 33, 49].

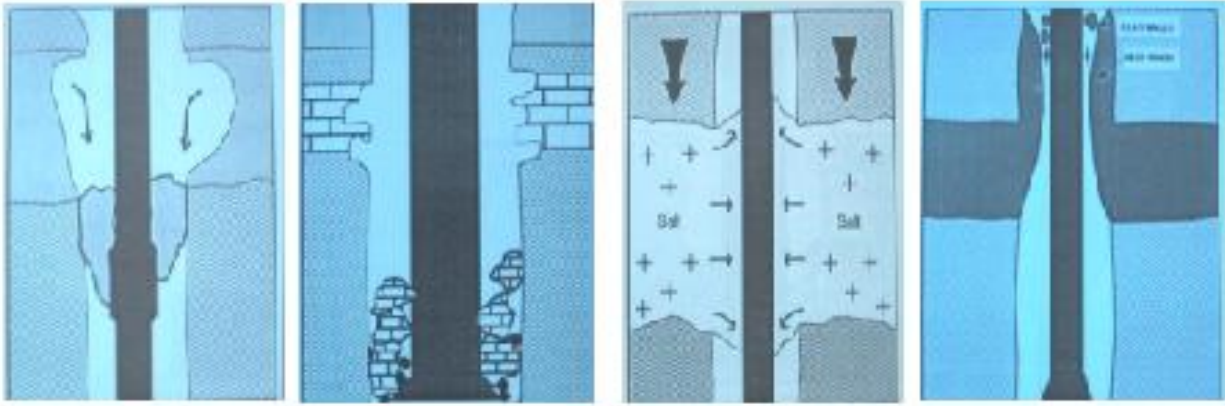


Figure 8 - Hole Instability scenarios

*From left: 1. Unconsolidated formation collapses and fall's into wellbore and jams DS. 2. Fractured formation collapses after drilled, falls into wellbore and jams DS. 3. Salt formation with plastic behavior packs around DS. 4. Reactive clay with some gumbo mud-balls [25][49].*

### 2.3.3. Insufficient hole-cleaning

Hole cleaning ability is how good we can remove drilled formation from the wellbore. Hole cleaning depends on flowrate, ROP, drillpipe rotation, hole size and hole angle to name a few [32]. As we go deeper the annular area is reduced and the flow rate needed to properly clean the hole is reduced. Though there are limitations due to ECD and equipment requirements, insufficient hole-cleaning is usually not a big problem in vertical sections. However in deviated and horizontal wells, insufficient hole-cleaning becomes a concern and higher annular velocities are required to clean the well. Are the hydraulics inadequate, cuttings start to accumulate. In the horizontal sections cuttings bed will keep growing with an accompanied increase in ECD until a pack-off occurs. This restricts the wellbore and can be seen as a spike in pressure. In the deviated sections especially between 45-60 degree inclinations, the bed will accumulate until the gravitational forces causes the bed to release and slide down the slope of the borehole wall and at some point pack-off the string. In either case, if the pack-off is severe enough the pipe may become stuck. To avoid avalanches, it is important to maintain circulation and mud properties [31, 28].

### 2.3.4. Lost Circulation

Lost circulation is the reduction or absence of fluid flow up the annulus when drilling fluid is circulated into the well through the drillstring. In this situation the entry volume rate does not equal the volume leaving the well. In some situations one may have small losses to the formation, typically 20 bbls/hr. The definition may vary among different companies, but seepage of an acceptable volume into the formation does not necessary mean a well control situation [27].

A Lost circulation situation during drilling is critical because the drilling fluid column acts as the primary barrier. Lost circulation then weakens your primary barrier or removes it completely. If the reduction in mud column height in the annulus is severe enough the BHP may drop below the pore pressure (PP) and induce a kick [25]. Lost circulation may be due to:

- Cuttings accumulation downhole may increase the hydrostatic head of the annulus mud column and create a too high average mud weight or ECD. This may fracture the formation and one start losing mud into the fractures.
- Karsts – big voids /caves in the underground that cause the loss of the complete mud column if drilled into.
- Naturally fractured formations - Carbonates often have natural fractures which may cause lost circulation.
- A surge pressure caused by tripping in the drill pipe to fast may be sufficient to fracture the formation and induce losses.
- Faults – Large faults may be active or be reactivated and provide large flow channels that direct the drilling fluid away from the bore hole causing the fluid level to drop and induce lost circulation

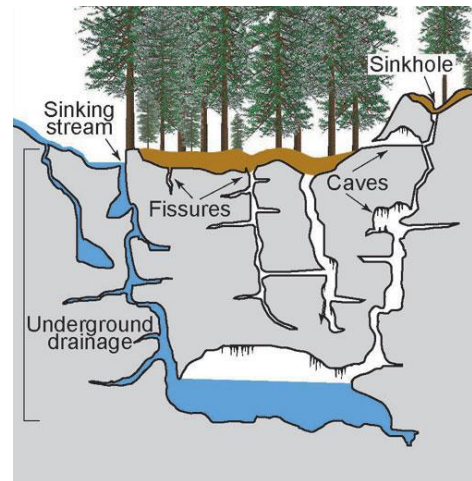


Figure 9 - Fracture network and karst formation [34]

- Fracture growth due to in-situ stress field may cause significant loss of drilling fluids

[20, 25]

### 2.3.5. Kick

A kick is defined as “a well control problem in which the pore pressure found within the drilled rock is larger than the mud hydrostatic pressure acting on the rock” [39]. When this occurs the formation pressure has a tendency to force formation fluids into the wellbore, this fluid flow is known as a kick. A kick that is not brought under control may easily develop into a blowout. This is the most severe incident that can happen in a drilling operation.

#### 2.3.5.1. Kick Sources

A kick is initiated when the borehole pressure (BHP) drops below the PP. During a drilling operation this may happen due to:

**Insufficient Mudweight** – Using too low density mud may at some point make the BHP lower than the PP.

**Swab & heave effect** – A negative swab-pressure may be created if a certain volume of mass/steel is removed from the hole too fast. This may be due to tripping out too fast or caused by the effect of heave when the drillstring is in slips on a floating drilling unit. The reduced pressure created may be sufficient to allow fluids to enter the wellbore.

**Improper fill-up** – As drillpipe (DP) is Pulled Out Of Hole (POOH) and the hole is not refilled the annulus mud-level will drop. At some level the hydrostatic head from the annulus fluid column will be insufficient to maintain the BHP above PP and a kick is introduced.

**Gas/Water Cut Mud** – During drilling the mud may get contaminated by saltwater or gas from the drilled formation. This lowers the average density of the mud-column and this reduction may be sufficient to drop the mud hydrostatic pressure below PP [40].



**Gas diffusion** - When using Oil Based Mud (OBM) in deep wells (high pressures and temperatures), gas may diffuse and completely dissolve in the base oil of the mud even if the well is in overbalance. The gas stays dissolved until it is circulated upwards and reaches the pressure and/or temperature conditions that allows it to boil out. This happens very fast and is a large concern particularly in HPHT wells [40].

**Lost Circulation** – As mentioned, lost circulation may occur due to a diversity of reasons. The concern is that the annulus mud-level decrease accompanied with a lost circulation event, may reduce the mud-column sufficiently to drop the mud hydrostatic pressure below PP and thereby introducing a kick [26, 42].

#### 2.3.5.2. Kick Potential

The severity of a kick will depend on several factors: The pressure differential between the formation pore pressure and the mud hydrostatic pressure, along with the permeability & porosity of the formation, are the main factors related to evaluation of the formations kick potential. To illustrate; in the same pressure regime, the kick potential of a sandstone may be high due to high permeability, whereas a shale may have the same porosity but almost zero permeability: This would give the shale almost the same pore volume as the sandstone, but the pores are not connected. The shale therefore have a low flow potential, hence the shale would have a low kick potential because a kick is an inflow [26].

#### 2.3.5.3. Kick Handling

When a kick is taken it needs to be circulated out of the well before safe drilling can continue. Depending on the kick size and the company kick handling procedures one can choose to gain well control / “kill the well” in three ways:

**Driller’s method** – Uses 2 circulations to kill the well. First the well is shut in ( BOP is closed). The Shut In DrillPipe Pressure (SIDPP) and Shut In Casing Pressure (SICP) is noted after pressure stabilizes. The kick is circulate out through the choke & chokeline

while maintaining a constant bottom hole pressure. Then sufficient mud weight is calculated and weighed up and pumped according to a calculated kill or pump sheet. This is done while maintain a constant bottom hole pressure. Usually at least one additional bottoms-up is circulated after well control is reestablished

**Wait & Weight Method** – Uses 1 circulation to kill the well. The well is shut in, pressures are read and sufficient mud weight is calculated and weighed up, pumped according to a calculated kill-sheet, while maintaining constant bottom hole pressure. Usually one additional bottoms-up is circulated after well control is reestablished. This is considered a more “advanced” method as it involves more calculations on the fly and is often referred to as the “The Engineer’s Method”.

**Bull heading** – This is often considered “the last way out” as in this situation the kick is not circulated to surface but pumped back into the formation. Significant bottom hole pressure increase is usually seen with the result of hydraulic fracturing of the formation. A bull heading operation in a reservoir section will in most cases destroy the flow potential of the near borehole area. In such a case one may need to plug back the drilled reservoir section and drill a sidetrack to get a productive reservoir section [35, 26, 42].

#### 2.3.5.4. Example: Kick Handling - Time & Cost

A kick situation is not only a critical situation when it comes to well control and safety, but also to time consumption. This can be illustrated by the following example;

A vertical well takes a kick at 13 000 ft TVD depth. The last casing shoe was set at 8200 ft. The drill collar section is 1000 ft long. The Well is killed using drillers method. Kill rate is 144 GPM; 4.6 gallons per stroke and 30 SPM (Strokes Per Minute).

Drillpipe inner capacity 0.74 gallon/ft

Drillcollar (DC) inner capacity 0.32 gallon/ft

Annular capacity

DP – Csg: 1.95 gallon/ft

DP – OH: 1.9 gallon/ft

DC – OH: 1.22 gallon/ft

Volumes	Calculation	Volume (Gallon)	Time (min)
Drillpipe section	$(13000-1000) \times 0.74$	8880	
DC	$1000 \times 0.322$	322	
<b>Drillpipe + BHA</b>		<b>9202</b>	<b>9202/4.6= 2000 Strokes</b> <b>2000/30= 67 Min</b>
DC - OH	$1000 \times 1.22$	1220	
DP - OH	$(4800-1000) \times 1.9$	7220	
DP - Csg	$8200 \times 1.95$	15990	
<b>Annulus</b>		<b>24430</b>	<b>24430/4.6= 5310 strokes</b> <b>5310/30=177 Min</b>
<b>Total</b>		<b>33632</b>	<b>243.7 min</b>

Table 2- Calculated time to displace the whole annulus with new mud

Using Driller's method; assuming this is a perfect operation where no time is wasted between pumping the 2 different displacements and one additional bottoms-up after the kill. This gives us a total of 3 annulus volumes and 1 drillstring volume to circulate before drilling can commence. The time usage on this kick will be  $(3 \times 243.7) + (1 * 67) \approx 798$  minutes or 13.3 hours. With an operational rig-rate of 0.9 MM \$ this kick cost's at the bare minimum  $\approx 0.5$  MM \$ or approximately 3 MM NOK.

## 2.3.6. Stratigraphic and Lithological challenges

### 2.3.6.1. Key Seating

Boulders, stringer, rapid formation changes or soft formations may cause the bit to deflect from the planned trajectory and the recovery back into the planned trajectory may cause doglegs of different severity. If the dogleg is severe enough this will cause the drillstring to make contact with the side of the wall. As drilling proceed, gradually a smaller diameter groove in the borehole wall will then wear away. A cross section view of the borehole at this point will show that the borehole have been shaped much like a “keyseat”. This does not introduce problems while drilling ahead, but may get the larger drill collar’s stuck on the way out [29].

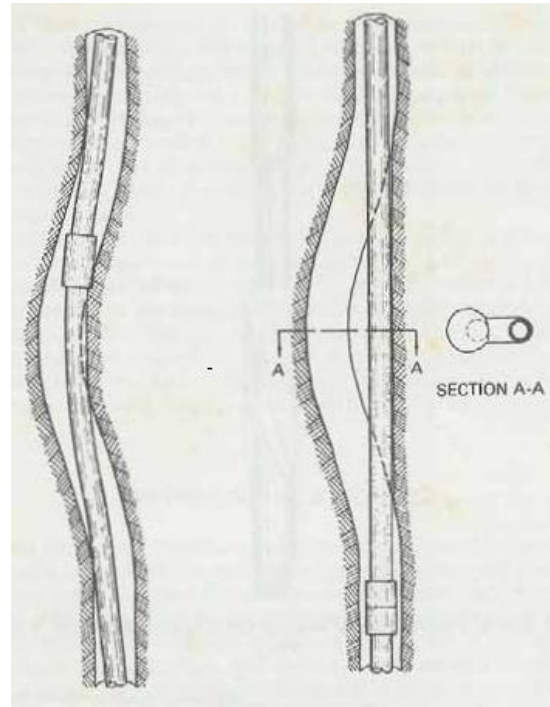


Figure 10 - Key seating [41]

### 2.3.6.2. Abrasive Formations

Some formation types are very abrasive. They are very hard and rough and which make them a challenge to drill through. Certain types of specialized drill-bits are able to drill through them but still it requires a lot of time to do so. Chert, hard sandstones and basalts are examples of abrasive formations. When they are encountered in small layers at the time they are referred to as stringers. They cause reduced ROP, bit wear, additional bit trips due to worn out bits and tight hole [25, 43].

### 2.3.6.3. Stringers - Natural Whipstocks

As mentioned, stringers are thin hard layers of rocks. In some cases the stratigraphy changes rapidly between hard and soft formations. When drilling hard formations one usually needs more WOB than in soft formations. If drilling through such formation layers a so called natural whipstock may be formed, and the bit will deflect from the planned wellpath [44]. Soft formation may in addition be unconsolidated or fractured. This may result in cavings, washouts and collapses. This produces a very unfavorable hole, which it can be hard to return back to the original wellpath from, create stuck pipe, issues with cementing the casing and in worst case not be able to get the casing down at all. Figure 11 shows an example [25].

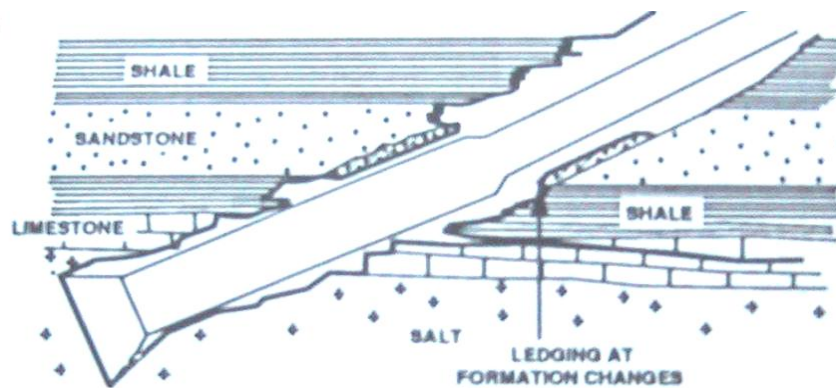


Figure 11 - Borehole instability due to interchanging formations [49]

### 2.3.7. Stuck Pipe

Stuck pipe is a critical situation. It adds on time usage and reduces flexibility. Stuck pipe may introduce large fishing operations and in worst case it may be required to shoot the string off. Then the well also needs to be plugged back and a sidetrack needs to be drilled. This will result in a major additional cost add-on.

There are large numbers of reasons why pipe may get stuck. Some of them are man-made, like when we get stuck in hardware or equipment placed in the well, but the far largest portion of reasons are due to the downhole environment and formation properties. A lot of the root causes of stuck pipe incidents have already been mentioned in sections above [25, 30].

- Insufficient hole-cleaning / Cuttings accumulation → Packoff
- Abrasive formation → Under gauge hole
- Wellbore geometry → Key seating
- Unconsolidated formations / Boulders / Fractured, formations / → Packoff & jamming of string
- Mobile, Reactive and Geo-Pressured formations → tight hole

In general, anything that can pack around the drillstring or drilling assembly may cause a stuck pipe incident. But there is also another way to get the drillstring stuck and that is due to a phenomenon called differential sticking.

#### 2.3.7.1. Differential sticking

When mud is circulated through an overbalanced well, the permeable formations will act as a filter for particles in the mud. Depending on the amount of clay particles in the mud and the differential pressure between the BHP and the formation PP, a mudcake of a certain thickness will build up. This mudcake will grow until the cake more or less seals off the formation. The differential pressure across the mudcake creates a normal force that can hold the drillstring to the wall and make it stick. This force depends on the area of the drillstring that the force is acting on, and the size of the differential pressure. Differential sticking usually occur when the reservoir (permeable formation) pressure is low, the BHP is high, or both. The longer time a differential stuck string stays stationary / stuck, the more likely it will remain stuck. This is because when the string is stationary the contact area increases and thereby the stuck force increases. This makes differential sticking a very time critical event in terms of response as well as terms of potential time loss, as the consequence will be to shoot off the string and sidetrack the well [36, 45, 49].

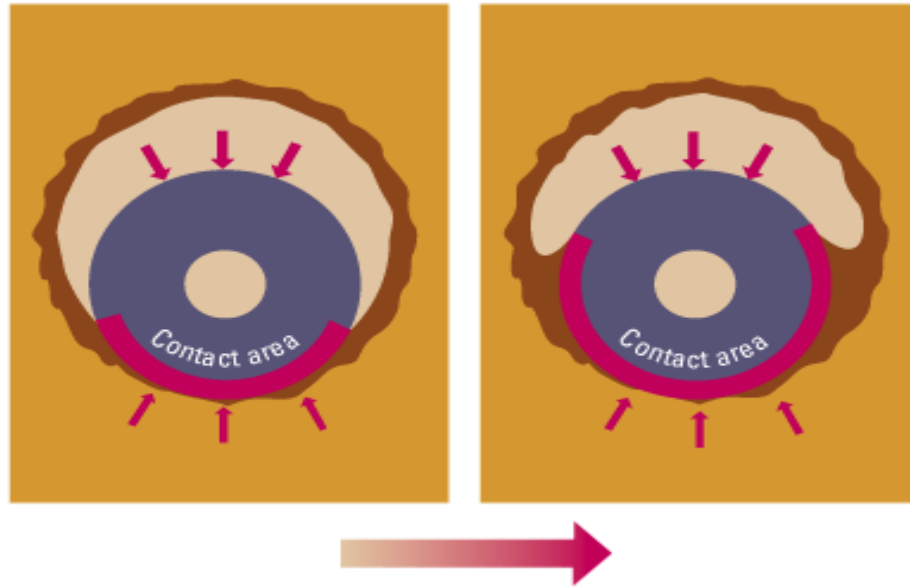


Figure 12 - Differential stuck pipe

The dark brown is the mudcake. From left to right you see how the contact area has increased [36]

### 2.3.8. Handling Drilling Challenges

To maintain an efficient drilling operation, it is inevitable to take action and plan to avoid, mitigate and handle the challenges the subsurface facilitate. The challenge is that one can never know what exact challenges the subsurface will reveal. What is “known” before the well is drilled is always very uncertain. Substantial work in the planning phase helps to prepare for, mitigate and avoid many of the challenges [46]. Still one need to consider the information received during the drilling operation, the Real-Time information. This is the real data from the subsurface and enables us to make good decisions, act preventive, mitigate risks and optimize the drilling process. These data are very valuable, but they need to be taken advantage of and used in the right way [4].

## 2.4. Drilling optimization

Drilling Optimization has been a subject that has been based on a lot of different concepts the last 4-5 decades. The first official application was in 1967 and James L. Lummus states in 1970 that:

*“Optimized drilling techniques have significantly reduced drilling costs....Results indicate that better data, more experience and confidence will result in greatly savings in the future” [3].*

Since then the technology, data availability and quality have developed drastically and in 2004 D. C-K Chen from Sperry Drilling in Halliburton defined traditional drilling optimization as:

*“Drilling optimization is a process that employs down hole and surface sensors, computer software, measurements while drilling (MWD), and experienced expert personnel – all dedicated to reduce trouble time and increase drilling efficiency” [4].*

The well construction cost profile has also developed and all though the drilling optimization has become significantly improved, still 15 - 35 % of the well cost is due to NPT associated with wellbore integrity, drillstring integrity and downhole failure [37]. A study showed that failure due to vibrations alone was in the range of \$300 million per year [47]. In other words, there is still work to be done, and as the economical margins on each well keep shrinking the significance of drilling optimization rises.

### 2.4.1. What is drilling optimization?

The term is today used in almost every aspect of the drilling industry. Measures as tools, software, procedures etc that either reduces the time used, the risk for encountering a problem or in some way improves anything in any part of the drilling process is seemingly termed drilling optimization. So, to clarify the further discussion of drilling optimization we will be referring to Halliburton and Chen’s definition [4].



## 2.4.2. Conventional Drilling Optimization

As Chen defined traditional drilling optimization, it is a process that uses down hole sensors, surface sensors, computer software, measurements while drilling (MWD) and experienced expert personnel to reduce trouble time and increase drilling efficiency. Figure 13 shows the conventional optimization process as a closed circle where you find the drilling optimization specialist in the center.

This cycle have been and is used by drilling optimizers and drilling engineers. It is a methodology that is universal and can be applied in some variant to most optimization processes.

Through the last decade new technologies within data transfer, storage capacity and IT software have allowed us to get more data with higher quality faster. In drilling optimization this is reflected through the development of new technologies related to information management and real-time decision making. The drilling optimization circle has changed from being related to the pre, real-time and post face of the operation to be a real-time circle consisting of Real-Time modeling, Integrated Real-Time Modeling and Data and Real-Time –Operation-Center (RTOC). Figure 14 shows the new circle [4, 50].

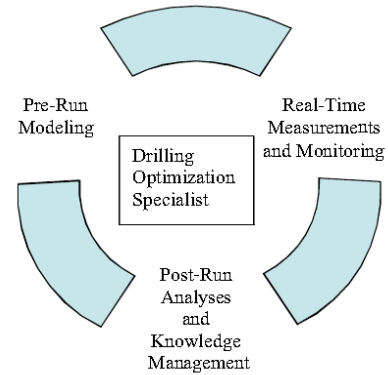


Figure 13 - The traditional Drilling optimization cycle [4]

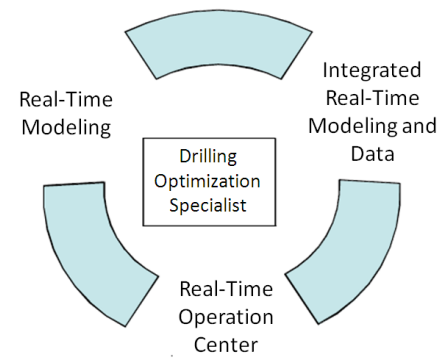


Figure 14 - The New Drilling optimization circle [4]

### 2.4.3. Real-Time Modeling

Conventionally modeling is done in the planning of the well to provide predicted data. When the drilling starts, this model needs to be continuously updated with the real data values and this is an impractical and time consuming way of working. Real-Time modeling is continuously running and automatically updating the model. The parameters being optimized and the categorization used are still the same, however, Real-Time Modeling allows for a more continuous and effective monitoring and thereby increases the ability to prevent drilling accidents or optimize drilling parameters [4].

### 2.4.4. Integrated Real-Time Modeling and Data

It is a fact that the Real-Time modeling procedures produces more reliable results than the conventional ones, but to assure that the information that is delivered from this process is useful and for the diagnosis of the downhole environment to be identified it is almost inevitable to integrate the modeling results with downhole data. Typically modeling and data integrations of benefit are [4]:

- BHA Dynamics models & downhole vibration data
- Pore pressure model & Pressure (PWD) and Formation test While drilling (FTWD) data
- Hydraulics model & PWD data
- Hole cleaning model & PWD data and mud solids
- Wellbore stability model & LWD imaging data

### 2.4.5. Real-Time –Operation-Center: RTOC

For the optimization process to be successful, a rig-to-office integration needs to be established. This allows the process to be monitored 24/7 by an asset team and allows an increased multidisciplinary level on critical decisions. The drilling optimization specialists in the RTOC

are usually experienced field staff and they serve as the communicator towards the drilling supervisor if precautions or interventions prior to an operation should be taken [4, 48].

The new cycle does however not suggest that the old one should be removed. The Drilling optimization process still starts in the planning phase with pre-run modeling etc. The integration of the two would incorporate the benefits from both cycles and allow for an even further optimization of the operations [51].

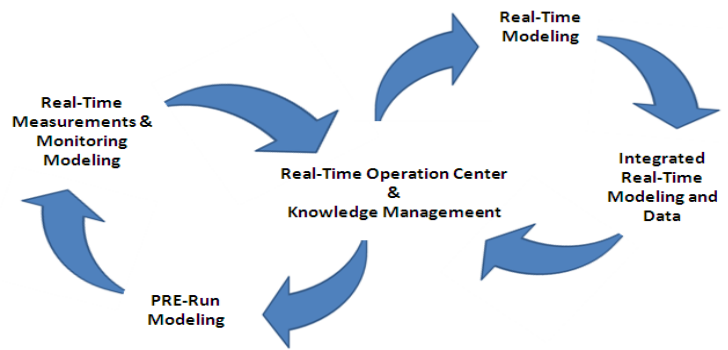


Figure 15 - A integrated circle of drilling optimization workflow

#### 2.4.6. The Drilling optimization Elements

The drilling optimization process has 3 main focus points: Drillstring integrity, Wellbore Integrity and Hydraulics Management.

##### 2.4.6.1. Drillstring integrity

Drill string integrity focuses on the prevention or reduction of mechanical overload, protection from fatigue and minimizing excessive shock and vibrations. The most important issues are downhole vibrations like BHA and bit whirl, stick-slip and bit-bounce but also BHA buckling and torque & drag. Specialized computer software provides dynamics and static BHA modeling for critical Rotary speeds and torque and drag modeling.

Downhole and surface vibration detection sensors allow the ADT service specialist to measure harmful vibration modes and identify active vibration mechanisms. Correlation with M/LWD data and surface drilling parameters enables corrective actions to be taken to reduce damaging

vibration and improve performance. Root cause analysis and effective documentation ensure continued improvement in bit and BHA design, and makes it possible to further design out vibration problems and deliver continued performance improvement [4, 50].

#### 2.4.6.2. Hydraulics management

Hydraulics management focuses on keeping the hydrostatic and dynamic pressures between critical upper and lower operating limits, optimizing circulating pressures, hole cleaning and clean-up cycles, optimizing ROP and tripping speed without exceeding the pressure limits.

This is done by the ADT and/or AFT (Applied Fluid Technology) specialist by using static and RT-models for hydraulics, hole-cleaning and Torque&Drag to predict the expected drilling environment.

Hydraulics models can predict the effect of temperature, pressure and compressibility on downhole mud properties and the resulting hole cleaning efficiency and system pressures [4, 50].

#### 2.4.6.3. Wellbore integrity

In Wellbore integrity the drilling optimization process concerns about determining the upper and lower wellbore pressure limits through simulation, modeling and prediction of PP, FP and Bore Hole Collapse Pressure (BHCP).

Pore Pressure Prediction and Geomechanical Analysis Software are used in the pre-well analysis and wellsite surveillance services to determine the mechanisms of pore pressure generation within a prospect. Advanced pore pressure, geo-mechanical and basin models can also be developed and updated in real time. Real-time formation evaluation data makes the Applied Drilling Technology (ADT) specialist able to update as well as refine the expected wellbore conditions. Based on this the ADT specialist makes recommendations to ensure wellbore integrity and stability, maximize ROP, extend target depth criteria and optimize or eliminate casing points. His prognosis is also used to reduce the uncertainty in mud weight decisions, and

can be integrated with the Hydraulics Management service to maximize performance conditions through selection of proper mudweight thereby indirectly assisting in maintaining a safe drilling operation [4, 50].

#### 2.4.6.4. Data sources and systems

- **LWD measurements** - sonic, density, resistivity, Formation-Pressure While Drilling FPWD, LWD imaging tools and seismic while drilling - SWD, significantly improve the quality of the optimization services [4]
- **MWD measurements**
  - o Downhole Annular pressure, Bore Pressure and temperature measurements - supplied by the PWD tool. Used in all analysis in all three elements of the DO
  - o Borehole dimensions – supplied by acoustic caliper tools, provide a detailed image of the borehole wall, increases accuracy of wellbore volume calculations
  - o Downhole vibrations – Supplied by vibration sensors like DDS, gives Average, Peak and Burst (instantaneous) vibration readings along all three axes provides information on loads of equipment and vibration mechanism.

**Surface Data-logging Parameters** – SPP (Stand Pipe Pressure), TT (Trip Tank) and pit volumes, Flow in/out, gas levels, block height, RPM, depth, WOB, Hookload, Surface torque and Mud temperature [4, 50].

### 3. The Well study

#### 3.1. Well selection Criteria's

The objective with this assignment was to see identify and quantify the value of doing drilling optimization and the processes it facilitates.

The first stage was to get a clear understanding of what drilling optimization is and what is considered drilling optimization. Drilling Optimization, as the services described in the theory chapter, are related to the drilling phase of the well construction. Figure 16 shows example of how a time schedule for the different phases of the well construction may look like. This is just to illustrate what time element of the well construction that drilling optimization primarily effects. There are additional secondary effects of drilling optimization that impact the other phases, as completion, but these will not be evaluated here. The ratio between the phases is also not a governing average; it will be very dependent on how technical advanced the well is in terms of both drilling, completion and environment.

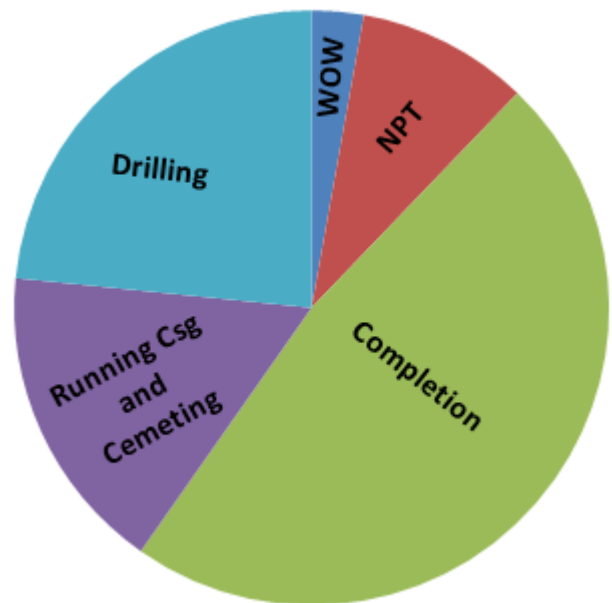


Figure 16 - Distribution of time consumption related to the different phases of the well construction process

Second, one needs to find data, in this case wells, which are comparable in the light of these objectives. This involves establishing selection criteria that need to be fulfilled for the well's to be considered comparable. The selection of wells was done based on the following criteria:

### 3.1.1. Technical aspects

#### Drilling Facilities

It was decided that the wells had to be drilled from the same drilling facility. This will remove the factor with different capabilities and specifications related to each drilling facilities. It would also remove to some extent the human skill factor, as this would keep the same people rotating the rig and thereby the well's would be drilled with people from the same skill pool. The differences between each crew would still be present, but it was considered as an impossible task to remove this element.

#### Well trajectory

The well trajectory is a major factor when it comes to the technical level of the drilling operation. Inclination, turns and dogleg's do to a large extent have an impact on the difficulty of hydraulics and hole-cleaning, directional control and torque & drag mitigation. It was therefore considered important to consider wells with more or less the same level of difficulty when it comes to well trajectory.

#### Hole section

There will be different challenges in different hole sections. In the 36'' hole section one need to take special concern about the level of consolidation of the formation, however this does not usually introduce the same level of concern in the 12 ¼ Section. The performance study in each well will therefore to a large extent be section like.

### 3.1.2. Geo-Technical aspects

There are a lot of different challenges related to drilling into the subsurface. Different formations may or may not have facilitated special conditions or properties which make them easier or harder to drill. This is a highly analyzed and debated theme and it was therefore made an effort

to select wells that was drilled in the same field and not too far from each other. In addition to the well trajectory criteria, this suggests that the general lithology the wells are encountering will to some extent possess the same properties and thereby introduce the risk for the same challenges.

### **3.1.3. Drilling Optimization services**

The idea behind the study is to try to quantify the value of drilling optimization. It was therefore imperative that the wells that were studied had been subject and exposed to the same level of drilling optimization services.

## **3.2. Source of Information**

The well study covered 15 North Sea Fields and involved 31 different drilling facilities, permanent as well as mobile. The End Of Well Reports made by the Directional Drilling, Measurements while drilling, Surface data logging and Advanced Drilling Technology service lines and the operator company's drilling program were used as the source of information in the study. Eight well's were selected and considered appropriate for comparison. These wells will be referred to as well #1 - #8 in further discussion.

The data presented in each section is based on the total runs needed to complete that particular holesection. This means that if it took 3 runs to drill a section the hours used in the analysis is the cumulative hours in these 3 runs. As an example, the Below Rotary Table (BRT) Hours will be the sum of the BRT hours from run 1, 2 and 3 in this particular hole section.

## **3.3. Operational planning & measures**

The wells considered were drilled from the same rig. The 8 wells were drilled in 2 batches. Batch 1 contained well #1 - #4 and batch 2 contained well #5 - #8. In both batches the 36" and 26" holes was drilled and cased off before the 17 ½ ", 12 ¼" and 8 ½" hole sections were drilled. All wells were subject to the same drilling optimization services. The drilling services for the first 4



wells were contracted and governed by a contract without performance incentives. The second batch, well #5 - #8, was governed by the same contract contact but with performance incentives. The rig spread rate is assumed to be 900 000 USD / Day, the spread rate includes all the services and is the operational dayrate the operator company face.

### 3.3.1. Planning

The formations in the upper part of the well were drilled through a low pressure gradient area. In the formation that was expected to be encountered in the lower part of the well, it was believed that high stress level in these formations would have the necessary strength to avoid drilling problems. However, considerable design and planning were undertaken to optimize the penetration through the lower stress zones and assure a stable and robust well design.

Expected fracture pressure, pore pressures and temperatures were simulated and estimated based on offset well data and LOT's.

Correction software for both local and external magnetic disturbance was used to calculate the expected magnetic field strength through the well trajectory to assure that survey accuracy could be verified when drilling and that anti-collision procedure would be valid.

Torque & Drag simulations was carried out with regards to: Helical buckling – rotating, Helical buckling – Non Rotating, Sinusoidal Buckling – all operations, Slide Drilling, Rotation on bottom and tripping out.

Critical rotary speed analysis was performed based on the planned BHA design.

Hydraulics simulations on circulation pressure, shear rate and shear stress was done based on BHA and drillstring design.

Optimal centralizer placement and spacing simulations was done for the planned well trajectory to assure optimum primary cementation.

### 3.3.2. Real-Time Monitoring

The following real-time monitoring was done by drilling optimization specialists:

- Real-time Hole cleaning; observed and theoretical volume changes
- Real-Time Torque & Drag; rotating weight, up weight, down weight and off bottom torque
- Real-Time SPP, flowrate and ECD
- Real-Time MSE – Mechanical Specific Energy: A pure drilling efficiency indicator based on the ratio of effort put into the drilling action (RPM, WOB, and Torque) and the effect of that effort (ROP). Higher MSE indicates lower drilling efficiency.

### 3.3.3. Optimization

The same optimization services were applied to all wells. However, after drilling the first 4 wells some lessons were learned. This information was used to further improve the performance on the 2<sup>nd</sup> Batch, well #5-#8:

- Lessons learned regarding rig logistics and limitations was taken into account when preparing for the second batch
- Directional control was optimized through WOB, RPM, flowrate and ROP, from study and experience gained from batch 1
- Analysis and RT measurements confirmed that several stabilizers in the BHA could be removed, BHA design was optimized.
- Identified operational effects on MWD measurements – made aware of this so no halts would occur due to a “false alarm” of an event occurring downhole.
- Mud properties and displacement procedures was optimized based on hole cleaning and hydraulics analysis
- Data from the first batch indicated that it was possible to safely operate with a higher flowrate

In addition to implementing the experiences a large focus was put on improving the performance on a wider operational scale. The M/LWD coordinator described that the focus on performance and clear communication was increased. All three parties (service provider, operator and rig contactor) involved in the operation engaged in a very good teamwork. The targets were clearly communicated and the positive experiences from the first batch were highlighted and adopted. There was a continuous loop of feedback during the operation and a focus on standardizing the operations. Rig crew helped MWD crew, MWD crew helped rig crew and so on. All together this created motivation and unity among all three parties and resulted in everyone “pulling in the same direction”.

### 3.4. Well description

#### 3.4.1. Well trajectory

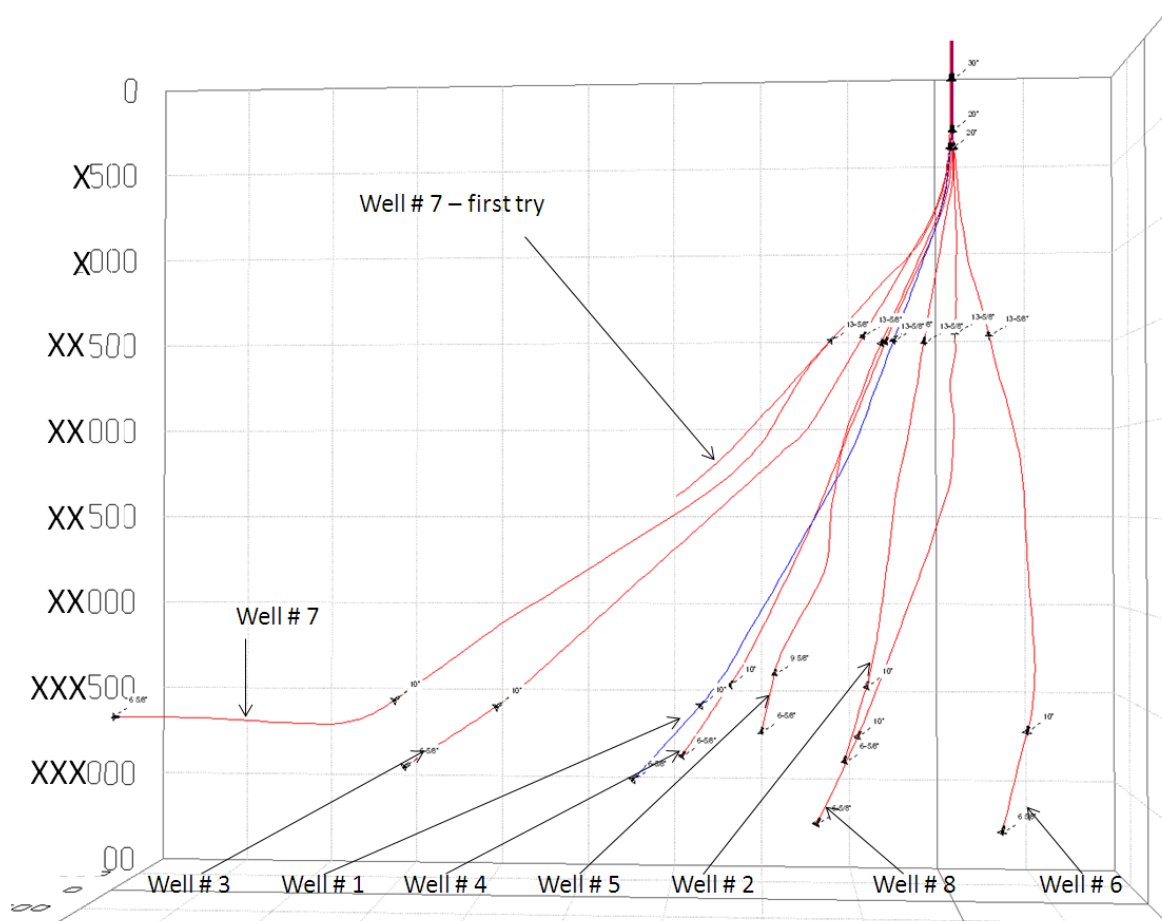


Figure 17 - 3D plot of the 8 wells final well trajectory

### 3.4.2. General Well Schematics

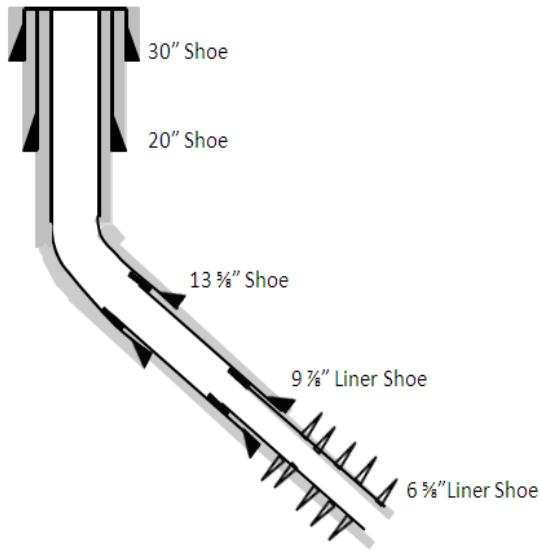


Figure 18 - General wells schematics excluded well #7

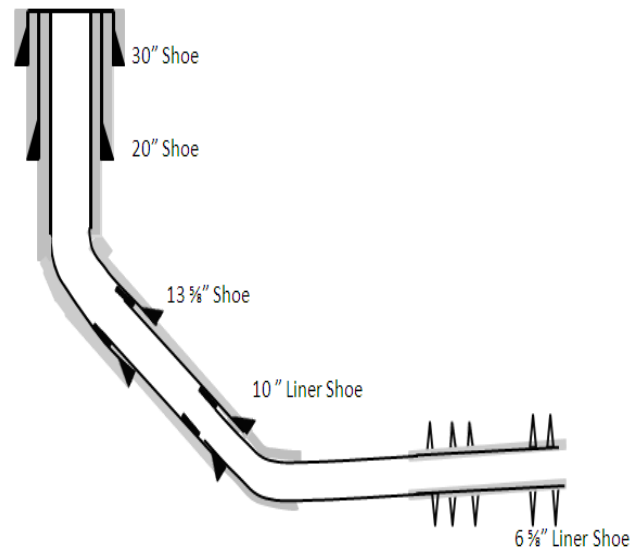


Figure 19 - well schematic of well #7

### 3.5. Operational Overview

All the 36" and 26" hole sections were drilled to TD with returns to seabed. They were cased and cemented without any problems. The operational overview for the lower sections is given in the following sections:

### 3.5.1. Well # 1

#### 17 ½” Hole section

The 17 ½” section was drilled with a Roller cone bit with a 3D Rotary Steerable System (RSS) assembly. The BHA was also supplied with Gyro, Gamma Ray (GR), Directional (DIR), Drillstring Dynamics (DDS) and Pressure (PWD) MWD sensors. The Well was displaced to OBM before the cement was drilled out. One Formation Integrity Test (FIT) was performed and the section was drilled to target depth (TD) while gradually increasing mud weight. No incidents were encountered during drilling. Problems with hole packoff and stuck pipe was encountered when POOH. The 13 5/8” casing was run and set without incidents.

#### 12 ¼” Hole section

The 12 ¼” hole section was drilled with a long gauge 12 ¼” Polycrystalline Diamond Compact (PDC) bit with a 3D RSS with Near Bit Gamma sensor (NBG). The BHA was also supplied with DIR, DSS, GR, Resistivity (RES) and Pressure MWD. The well was displaced to heavier OBM before starting drilling cement. Float, cement, shoetrack, shoe and new formation were drilled and an unsuccessful (FIT) was made. Pulled out of hole (POOH) and Ran In Hole (RIH) with a cement string to carry out a squeeze cement job. A new FIT performed and was accepted. Drilling commenced until a MWD-tool failed and the need to pull out of hole. At surface it was established that the bit was severely worn. A new long gauge PDC bit was installed and was RIH. The new bit drilled to section TD. The 9 7/8” liner was set with only minor mud losses.

#### 8 ½” Hole section

The 8 ½” hole section was drilled with an 8 ½” PDC bit with a 6 ¾” mud motor and DIR, GR, RES, DSS, Density (DEN) and Neutron Porosity (NP) MWD and a Formation-Pressure and PWD tool. The cement and shoe track was drilled out while the well was displaced to a lighter OBM. Mud weight was gradually increased towards TD and pressure points were taken during the run. Frequent flow-checks were performed. Some significant losses was observed through the

section but handled with LCM pills. After reaching TD the well was circulated and flow checked at two different locations before POOH. The 6 5/8" liner was run to setting depth, landed and set without any problems.

### **3.5.2. Well #2**

#### **17 1/2" Hole section**

The 17 1/2" hole section was drilled with a 17 1/2" Roller cone bit with a 3D RSS assembly. The BHA was also supplied with Gyro, GR, DIR, DDS and PWD MWD. The well was displaced to OBM while drilling out the cement. One unsuccessful FIT was made but the section was drilled to TD without any incidents. Hole instability problems and packoff was observed when POOH. A cleanout trip was performed before the 13 5/8" casing was run in hole and cemented. No incidents occurred during the setting and cementing of the casing.

#### **12 1/4" Hole section**

The 12 1/4" hole section was drilled with a 12 1/4" long gauge PDC and a 3D RSS with NBG. The BHA was also supplied with DIR, GR, RES, DDS and Pressure MWD. The cement and shoetrack was drilled out before displacing the well with a heavier OBM. One successful FIT was made and drilling commenced until it was required to POOH due to directional sensor problems. A new identical assembly was run in hole. Drilling continued until losses were encountered. The section was drilled to planned TD while managing losses. The 9 7/8" liner was then run and cemented without problems.

#### **8 1/2" Hole section**

The 8 1/2" hole section was drilled with an 8 1/2" roller cone bit with a 6 3/4" mud motor and DIR, GR, RES, DEN, DDS, NP MWD with a Formation-Pressure and PWD tool. Cement and shoe track was drilled out while displacing the well to a lighter OBM. The section was finished 212 ft

shorter than planned due to problems with low ROP. Significant losses were seen through the section but they were handled with Lost Circulation Material (LCM) pills.

### **3.5.3. Well #3**

#### **17 ½” Hole section**

The 17 ½” hole section was drilled with a 17 ½” tricone bit and a 3D RSS assembly. A Gyro MWD tool was used for surveys. The well was displaced to OBM whilst drilling out the cement and the MudWeight (MW) was increased gradually towards TD. One successful FIT was made. The section was drilled to TD without any major incidents. The hole was washed and ream out while pooling the string out of hole. The 13 ⅝” casing was run and set without any incidents.

#### **12 ¼” Hole section**

The 12 ¼” hole section was drilled with a 12 ¼” long gauge PDC bit with 3D RSS assembly with NBG. The BHA was also supplied with DIR, GR, RES, DDS and Pressure MWD. Cement and shoe track was drilled out while displacing the well to heavier OBM. One successful FIT was made. The section was drilled to planned TD without other problems than low ROP through hard stringers. The Mud weight was increased after reaching TD and the string POOH. On the way out one well volume was circulated after reaching the depth of a “flowing” formation layer. Mud weight was additionally increased at the same point and the string was pumped out of hole and to surface. The 10” liner was run in hole and cemented. During running the liner into the well, 175 bbl was lost and an additional 90 bbl was lost while circulating prior to the cement job. A total of 1200 bbl was lost during the cement job.

#### **8 ½” Hole section**

The 8 ½” hole section was drilled with an 8 ½” long gauge PDC bit with a 3D RSS assembly and NBG. The BHA was also supplied with RES, GR, DEN, NP and DDS MWD plus a Formation-



Pressure and PWD tool. The well was displaced to a lighter mud and washed down to the shoe. The shoe track was drilled out and an inflow was test performed. During drilling a higher formation pressure was indicated by pressure points that were taken. This resulted in the section being finished 311 ft shorter than planned. One unexpected gain was experienced but handled through procedures and an increase in MW. A cut and slip of the drilling line on drillfloor was performed during this time a total of a 1.8 bbl static loss was observed. The string was run back in hole to TD and the well was circulated bottoms up twice before a flow checked was performed. The string was then pulled to surface and the 6 5/8" liner was run and set without any problems or losses.

#### **3.5.4. Well #4**

##### **17 1/2" Hole section**

The 17 1/2" hole section was drilled with a Roller cone bit and a mud motor. The BHA was also supplied with Pressure, GR, DDS and DIR MWD. The formation was proved to be too soft to follow planned build rate but the target was still reached. A clean out run to TD was performed and confirmed good hole conditions. A (small) static loss of 2 bbl's/hr was observed. The 13 5/8" casing was run to setting depth and cemented without problems.

##### **12 1/4" Hole section**

The 12 1/4" hole section was drilled with a PDC bit with a 3D RSS. The BHA was also supplied with DIR, GR, RES, DDS and Pressure MWD. Then the float, cement, shoe, shoetrack and new formation were drilled, before a successful FIT was performed. Drilling was continued until a stringer was encountered and it was not possible to drill ahead. The 12 1/4" section was drilled to TD after POOH 2 times due to stringers. The Well was flow checked prior to POOH. The 9 7/8" liner was RIH and set with 51 bbl's loss during the cement job.

### **8 ½” Hole section**

The 8 ½” hole section was drilled with an 8 ½” Roller Cone Insert bit and mud motor. The BHA was also supplied with RES, GR, DEN, NP and DDS MWD plus a Formation-Pressure and PWD tool. The well was displaced to lighter mud and the float, cement, shoe, shoe-track and new formation was drilled before an inflow test was performed. Hard formations was encountered through large parts of the section and restricted the ROP through these. Six pressure points were taken while drilling. The section was drilled to TD and four pressure points were taken when POOH. The 6 ⅝” liner was set with slight mud losses observed prior to the cement job. The cement job was performed with full returns.

### **3.5.5. Well #5**

#### **17 ½” Hole section**

The 17 ½” hole section was drilled with a 17 ½” PDC bit with a 3D RSS assembly. BHA was also supplied with Gyro, GR, DDS and Pressure MWD. The well was displaced to OBM before drilling out the float, shoe track and cement. MW was gradually increased towards TD of the section. One successful FIT was performed and the section was drilled to TD without any incidents. The 13 ⅝” casing was also run and set without incidents.

#### **12 ¼” Hole section**

The 12 ¼” hole section was drilled with a 12 ¼” long gauge PDC bit with a 3D RSS with NBG. The BHA was also supplied with DIR, GR, RES, DDS and Pressure MWD. The well was displaced to heavier OBM while drilling out the float, cement, shoe, shoetrack and new formation before a successful FIT was performed. The 12 ¼” section was then drilled to TD without any problems. At TD the well was circulated bottoms up. After one bottoms up circulation two stands were reamed back and the bit run back to bottom where a flow check was performed. The Flow check showed 1.5 bbl/hr static loss rate. The 10” liner was then RIH; 589

bbl's was lost while tripping the liner in, 180 bbl's was lost while pumping LCM and spacer and 1073 bbl's was lost while cementing the liner in place.

### **8 ½” Hole section**

The 8 ½” hole section was drilled with an 8 ½” PDC bit with a 6 ¾ “mud motor. The BHA was also supplied with RES, GR, DDS, DEN and NP MWD, plus a Formation-Pressure and PWD tool. The cement was drilled and the well closed in due to gain of mud caused by nitrogen gas expansion. The nitrogen was circulated out before drilling continued. The well was then displaced to lighter MW prior to drilling out shoe, shoetrack and new formation. One inflow test was performed and pressure points was taken before entering the target formation. The MW was raised before drilling into the target formation. The section was then drilled to TD without any incidents. At section TD, the hole was circulated clean with 3 x bottoms up. The 6 5/8” liner was run and set without incidents and the cement job was conducted with full returns.

### **3.5.6. Well #6**

#### **17 ½” Hole section**

The 17 ½” hole section was drilled with a 17 ½” long gauge PDC bit with a 3D RSS. BHA was also supplied with Gyro, GR, DDS and Pressure MWD. The well was displaced to OBM before drilling out the float, shoe track and cement. New formation was drilled and a successful FIT was performed. High erratic torque readings were experienced and were traced back to the top drive. The string /BHA were reamed back into the 20” shoe before the top drive was repaired. After the top drive was repaired drilling commenced and TD was reached without drilling problems. The 13 5/8” casing was run and set without incidents.

## **12 ¼” Hole section**

The 12 ¼” hole section was drilled with a 12 ¼” long gauge PDC bit with 3D RSS with NBG.

The BHA was also supplied with DIR, GR, RES, DDS and Pressure MWD. The well was displaced to heavier OBM while drilling out the float, cement, shoe, shoetrack and new formation. 1 x bottoms-up was then circulated and a successful FIT was performed. The 12 ¼” section was then drilled to TD with some packoff’s and several stringer intervals. During drilling, problems with the Pipe Racking system caused a halt in the operation. In addition the weather conditions worsened and caused 1 day of WOW. At TD a flow check showed a static loss rate of 2.4 bbl’s/hr. The losses were with treated LCM pills before pulling out of hole. The 10” liner was run in hole. Some gain was observed when picking up the hanger. The well was then circulated bottoms-up (B/U) and flow checked. The situation was stable and running in liner continued. In total an effectively loss of 15 bbl’s were recorded while running in and cementing the liner.

## **8 ½” Hole section**

The 8 ½” hole section was drilled with an 8 ½” long gauge PDC bit and a 6 ¾” mud motor. The BHA was supplied with RES, GR, DEN, DDS and NP MWD plus a Formation-Pressure and PWD tool. No data was recovered from the Formation-Pressure and PWD tool during the first run. The cement was drilled and nitrogen was circulated out before drilling proceeded. The well was displaced to lighter OBM prior to drilling out the shoe, shoe track and new formation. A inflow test was performed. Drilling commenced and the MW was increased 3 times before reaching TD. At TD the well was again flow checked. The Flow check showed underbalanced conditions and 2 more MW increase’s was carried out before acceptable loss conditions were achieved. A total of 14 bbl were lost when tripping out of hole. A new bit, a rock bit, was then run with the same 6 ¾” MWD suite as used in the previous run. The bit did not drill any new formation as the purpose was to take the six pressure points that were not accomplished during the last run. The pressure points were taken and the 6 ⅝” liner was run and set without any problems

### 3.5.7. Well #7

#### 17 ½” Hole section

The 17 ½” hole section was drilled with a 17 ½” long gauge PDC bit and a 3D RSS. The BHA was also supplied with Gyro, GR, RES, DDS and Pressure MWD. The well was displaced to OBM while drilling out the float, shoe track and cement. New formation was drilled and a successful FIT was performed. Drilling commenced with relatively high ROP until cuttings handling on surface required a halt for sorting out jammed cuttings. The MW was increased gradually towards TD. Except for the jammed cuttings event, the bit drilled to TD without any problems or incidents. After reaching TD 1 x B/U was circulated before starting to POOH. The string was pumped out of hole until the depth of the 20” shoe was reached. A total loss of 18 bbl’s was observed while POOH. The 13 ⅝” casing was run and set without incidents.

#### 12 ¼” Hole section

The 12 ¼” hole section was drilled with a 12 ¼” long gauge PDC bit and a 3D RSS. The BHA was supplied with GR, RES, DDS and Pressure MWD. The well was displaced to heavier OBM while drilling out the float, cement, shoe, shoetrack and new formation. Pack-off and heavy losses were seen after a short period of drilling lead to POOH in order to perform a cement squeeze job. The cement squeeze job was performed and the same BHA was run back in hole. A successful FIT was performed and drilling continued until pack-off and wellbore breathing was observed. Gas was circulated out and drilling continued until MWD tool failed and POOH. Heavy losses and high connection gas readings was observed during the whole trip out of hole. It was decided to plug back the section and to do a side track. The section was cemented back and the new 12 ¼” section was kicked off. Problems with hole packing off were observed in the top of the new section. After reaching TD the hole was circulated clean with 5 x B/U before POOH. Only minor mud losses were observed when POOH but some tight spots were seen. The 10” liner was run and set with high mud losses recorded during the cement job.

### **8 ½” Hole section**

The 8 ½” hole section was drilled with a 8 ½” long gauge PDC bit and a 3D RSS assembly with NBG. The BHA was supplied with RES, GR, DEN, DDS and NP MWD plus a Formation-Pressure and PWD tool. The well was displaced to lighter OBM and the cement and shoe was drilled out. The rathole was cleaned out and an inflow test which proved static conditions was performed. Drilling commenced while pressure point while drilling was taken. The section was finished 387 ft before planned TD due to losses. The well was circulated clean and the string was pulled out while taking pressure points. The 6 ⅝” liner was run and set without any problems and no losses were recorded during the tripping or cementing of the liner.

### **3.5.8. Well #8**

#### **17 ½” Hole section**

The 17 ½” hole section was drilled with a 17 ½” long gauge PDC bit with a 3D RSS. The BHA was supplied with Gyro, GR, DDS and Pressure MWD. The well was displaced to OBM while drilling out the float, shoe track and cement. Drilled into new formation were a successful FIT was performed. The MW was increased gradually towards TD. The section was drilled to TD with average drilling rate 210 - 230 ft/hr and there were no incidents encountered. The hole was washed and reamed on the way out of hole. No problems were encountered while reaming/tripping out of hole. The 13 ⅝” casing was run and set without incidents and losses.

#### **12 ¼” Hole section**

The 12 ¼” hole section was drilled with a 12 ¼” long gauge PDC bit and a 3D RSS assembly with NBG. The BHA was supplied with GR, DIR, RES, DDS and Pressure MWD. The well was displaced to heavier OBM while drilling out float, cement, shoe, shoetrack. A successful FIT was performed after drilling xx ft new formation. Occasional stringers were encountered with signs of hole packoff when drilling through these. At some point a rapid increase in torque and pressure was seen. The string was pulled off bottom but it was not possible to get back on

bottom. Rotation and loss-free-circulation were re-established. A total loss of 110 bbl's of mud was recorded during the event. Indicators of insufficient hole cleaning led to the decision to limit the ROP which had a good effect. Directional problems were encountered and attempts to control the wellpath were unsuccessful. The hole was circulated clean with 2.5 x B/U before POOH to replace the 3D RSS and the bit. The remainder of the section was drilled with restricted ROP to be able to evaluate a good setting point for the 10" liner. Cuttings caused the string to hang up but one was able to work the string free. The MW was held constant through the whole section but flowrate adjustments were made frequently. After reaching TD and POOH the hole proved to be in a good condition. The 10" liner was run and set without incidents.

### **8 ½" Hole section**

The 8 ½" hole section was drilled with an 8 ½" PDC bit and a mud motor. The BHA was supplied with RES, GR, DEN, DDS and NP MWD plus a Formation-Pressure and PWD tool. The float was tagged, drilled out and the well closed to circulate out nitrogen. The well was displaced to lighter OBM while drilling cement. The shoe and new formation was drilled before a flowcheck was performed. Drilling continued and pressure points while drilling was taken. The MW was increased in steps up to the planned MW prior to drilling into the target formation. A flowcheck was performed in the top of the target formation. The section was drilled to TD without problems. Before POOH 3 x B/U was circulated and a flow checked performed. The flowcheck showed slight underbalanced conditions and the MW was increased prior to tripping out of hole. Four additional pressure points were taken on the way out. The bit was pulled bit to surface without problems. A total loss of 6.24 bbl's was seen when pulling out. The 6 ⅝" liner was run and set without any problems.

## 3.6. Performance Targets

As mentioned, the real value is added to the well construction process when the total time used to drill a well is reduced. This is because the biggest and primary cost driver is related to keeping the rig in operation. The total cost of the rig including all additional services is the rig spread-rate. To see the real value of the drilling optimization one need to look at how much time is saved by the increased focus and measures that the drilling optimization process emphasis. The following section describes the parameters and target that have been used in the performance development study.

### 3.6.1. Parameters

**NPT** – Non Productive Time is measured in hours and is the number of hours that the operation is in halt and not adding any value in terms of operational progress due to a failure.

**Avg. ROP** – Average Rate Of Penetration is the average rate one get when dividing the total footage drilled and divide it by the number hours drilling. This may be calculated for each run and for each section. The numbers used in this study is hole section averages.

**Drilling hours** - is the number of hours where the bit is on bottom and rotating / drilling.

**Circulation hours** – This is the number of hours where there has been circulation. The drilling hours will be included in circulation hours since one always circulate while drilling.

**Operational hours** – Operational is the time the tools in the BHA are operational. It is counted from the time the tools are initialized until they are out of hole and the memory data has been downloaded from the tool. The download may occur while the toolstring is in rotary table or after the toolstring and BHA has been layed down. This depends on what operations are planned and if the BHA is to be re-run. The operational hours include the circulation and drilling hours. It will also include static time when not circulating or drilling.

**BRT** – Below Rotary Table is the time the BHA is below the rotary table. This value is usually very close to the operational hours and will include the same time phases as the operational hrs.



**Footage** – The number of ft or meters formation that have been drilled in measured depth (MD).

### 3.6.2. Targets

To study the performance the following targets was used:

#### **Avg. ROP**

Avg. ROP has been used because it is one of the classic KPI for drilling efficiency. It has been debated how ROP may be an unjust KPI, but in this case the wells have the same trajectories in terms of inclination, turns, and horizontals. They are drilled through the same formations, from the same rig and by people with the same competence (to a certain degree). This suggests that the ROP in each section will reflect the drilling efficiency in a just way.

$$\mathit{Avg\ ROP} = \frac{\mathit{Footage}}{\mathit{Drilling\ hr's}}$$

Equation 1 - Average ROP

### **Drilling hours per foot**

Equation 2 shows drilling hours normalized on the footage drilled. The amount of hours needed to drill a section is directly related to the length of the section. By normalizing the drilling hours on the footage of the section it removes the influence of section length and the resulting parameter: drilling hours per ft can be compared between wells. As this number increases we are spending more time drilling each ft and vice versa. It is the inverse of the ROP but is included as it adds value when compared in relation to the same target for circulation and operational hrs.

$$hr's/ft = \frac{\text{Drilling hr's}}{\text{Footage}}$$

Equation 2 - Drilling hours per ft

### **Circulation hours per foot**

Equation 3 shows circulation hours normalized on the footage drilled. Also here are the section length and the hrs used directly related. By normalizing the circulation hours on the footage, the resulting parameter can be compared. As this number increases we are spending more time circulating per ft of formation penetrated and vice versa.

$$hr's/ft = \frac{\text{Circulation hr's}}{\text{Footage}}$$

Equation 3 - Circulation hours per ft

### **Operational hours per foot**

Equation 4 shows operational hours normalized on the footage drilled. Again, by normalizing the Operational hours on the footage the resulting parameter is comparable. As this number increases we are spending more operational time per ft of formation penetrated and vice versa.

$$hr's/ft = \frac{\text{Operational hr's}}{\text{Footage}}$$

Equation 4 - Operational hours per ft

### **Drilling to circulation hours ratio**

Equation 5 shows how the drilling to circulation hours ratio is calculated. It's a dimensionless parameter that shows what fraction of the total circulation hours that was used in the drilling phase. The closer the number is to 1, the smaller amount of hours is spent on circulating while not drilling.

$$\text{Ratio} = \frac{\text{Drilling hr's}}{\text{Circulation hr's}}$$

Equation 5 - Drilling to circulation hours ratio

### **Circulation to Below Rotary Table hours ratio**

Equation 6 shows how the circulation to BRT hours ratio is calculated. This is also a dimensionless parameters showing what fraction of the total time below rotary table were used for circulation. The closer the number is to 1 the fewer hours have been spent in static conditions.

$$\text{Ratio} = \frac{\text{Circulation hr's}}{\text{Below Rotary Table hr's}}$$

Equation 6 - Circulation to Below Rotary Table hours ratio

### 3.6.3. How to Interpret the Target Definitions

To clarify the following sections some expressions and use of words should be clarified.

**Displacement** – Is referring to the vertical distance between two curves for the same horizontal axis value (for the same “x” value in the coordinate system). The displacement can be constant, increasing or decreasing. The displacement is referring to how the relationships between two curves are developing.

**The value** – This is the numeric value that the graph is displaying for each horizontal axis value. This may be constant, increasing or decreasing. The value is referring to one graph and its development.

The only difference between the drilling hours and circulation hours is the non-drilling circulation hours. The displacement between these two curves therefore reflects the need or use of non drilling circulation. This should ideally be as low as possible.

The only difference between the operational hours and the circulation hours is the static hours. The displacement between these two curves therefore reflects the use of static time. This is mainly related to tripping out of the hole and connection time, but FIT, LOT and flow tests would also be included in this element.

As explained in chapter 3.6.1 and 2, the different targets are dependent on different time elements. The following examples are made to illustrate the meaning and relation between the targets. However, this is meant as supplement to understand the general relation between the targets. This is not an absolute truth and the curves development need to be seen in relation to the operational overview as well as possibility for discrepancies.

## Increasing and decreasing value

Figure 20 show an increasing value for all three curves. The displacement is assumed to be constant. The interpretation of this situation is that the total time to drill the section is increasing. Since the displacement is constant there is no events occurring that contribute to additional non drilling circulation time or static time. This curve development would typically be the result from gradually decreasing the ROR, where same add-on in time is experienced in all three targets.

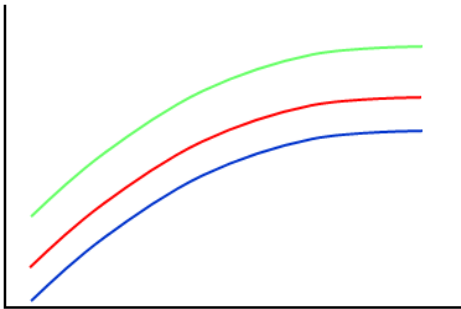


Figure 20 - Increasing absolute value

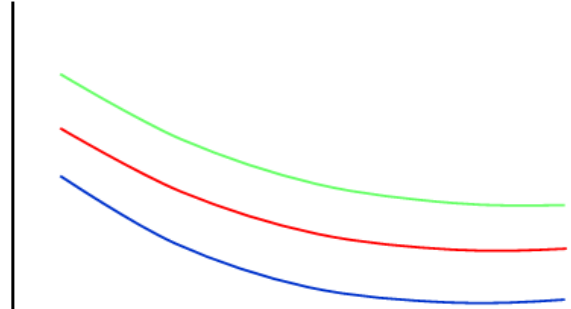


Figure 21 - Decreasing absolute value

Green curve represent the operational hours used per ft. Red curve circulation hours per ft and blue curve drilling hours per ft.  
Horizontal axis represent time section was drilled oldest to newest.

Figure 21 show the opposite development with a decreasing trend. The same explanation would be valid here, except here the ROP is gradually increasing. The ROP increase does not introduce any problems.

The operational hours and BRT hours are usually very similar in terms of hours. This is because the start and end times that they are measured between usually is very similar. In both the above cases the circulation hours to BRT hours ratio would be constant as long as the measurement of BRT hours are consistent. Both parameters would then increase by the same factor and the ratio remains the same.

### Increasing value and decreasing displacement

Figure 22 show that the values of all three curves are increasing and more time is spent in each section. In addition the displacement between all three curves is decreasing. The increasing drilling hours per ft – blue curve, can be explained by a decrease in ROP. But the circulation and operational hours per ft (red and green curve) does not increase by the same amount, they are increasing less.

The only difference between the circulation and drilling hours is the non drilling

circulation hours. The only difference between the circulation and operational hours is the static time element. This leaves us with an improvement within the time used in the static and non drilling circulation time elements. This implies that earlier they were spending more time with non-drilling circulation as well as more static time. As long as no events occurred the explanation for this curve development could be: the ROP is reduced, hole cleaning is less of a concern so the non drilling circulation hours is reduced and they are tripping faster hence less static time is used.

For this situation we could expect to see the ratio between the circulation and BRT hours to decrease. As mentioned the operational hours and BRT hours are usually very similar in terms of hours.

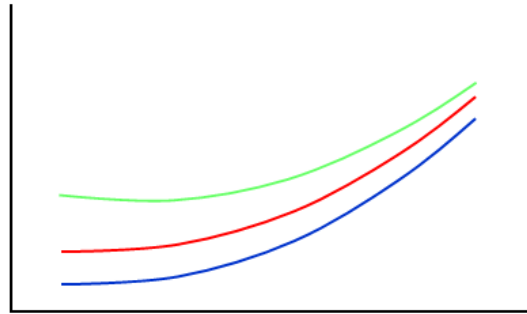


Figure 22 - Increasing value and decreasing displacement

Green curve represent the operational hours used per ft. Red curve circulation hours per ft and blue curve drilling hours per ft. Horizontal axis represent time section was drilled oldest to newest.

### Increasing Value and increasing displacement

Figure 23 show that the values of all three curves are increasing and the displacement between the curves is increasing. The increasing drilling hours per ft – blue curve, can be explained by a decrease in ROP. The circulation and operational hours per ft (red and green curve) does not increase by the same amount, they are increasing more. This causes an increase in displacement. This leaves us with a negative development within the time used in the static and non drilling circulation time elements. This development implies that earlier they were spending less time with non-drilling circulation as well as more static time.

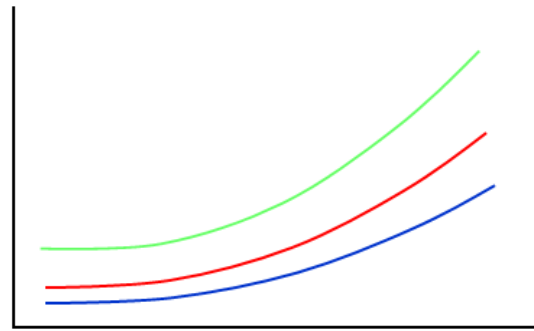


Figure 23 - Increasing value and decreasing displacement

Green curve represent the operational hours used per ft. Red curve circulation hours per ft and blue curve drilling hours per ft. Horizontal axis represent time section was drilled oldest to newest.

The explanation for this curve development, as long as no events occurred may be: that the ROP is decreasing, hole cleaning has become a concern so the non drilling circulation hours is increased to assure better cleaning and they are tripping slower hence more static time is used. For this situation we could expect to see the ratio between the circulation and BRT hours to increase.



### Decreasing value and increasing displacement

Figure 24 show that the values of all three curves are decreasing and the displacement between the curves is increasing. The decreasing drilling hours per ft – blue curve, can be explained by an increase in ROP. The circulation and operational hours per ft (red and green curve) are decreasing less. This causes an increase in displacement. Overall the development is positive because the value of all three curves is decreasing. However, the increase in displacement also indicates that the drilling efficiency is decreasing. More static and non-drilling circulation time is required to finish the section as the ROP increases. This is not how one ideally wants the development to be, we would like to have both positive trends, like in Figure 25. However, in a real life situation where one is optimizing the drilling performance, the development in Figure 24 may actually reflect a very healthy approach. The ROP is increasing; this means that more cuttings need to be removed from the well in the

same period of time. Sufficient hole cleaning is an important factor in maintaining trouble free drilling and possesses a large risk in terms of additional time usage. Figure 24 show that the circulation hours are not decreasing with the same amount as the drilling hours and are maintained on a higher level. This means that the non-drilling circulation hours are actually being increased. This may be a strategy to confirm that the hole is being cleaned properly before starting to gradually reduce the

non-drilling circulation time. It's a safe play which makes it possible retreat if one sees that the increase in ROP is too high and the hole cleaning strategy is not working. The operational hours show the same trend as the circulation hours curve, but it is not reduced by an amount of hours equal to the circulation hours. All the circulation hours are included in the operational time usage so if the reduction is not equal, the static element is stalling the reduction by an increase. The increase in static time in this case would be due to a slower tripping speed. In a hole cleaning point of view, cutting beds may have formed in parts of the well, and one may not have been

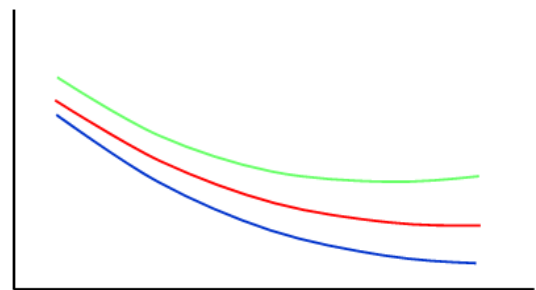


Figure 24 - Decreasing value and increasing displacement. Green curve represent the operational hours used per ft. Red curve circulation hours per ft and blue curve drilling hours per ft. Horizontal axis represent time section was drilled oldest to newest.

able to remove these. As the bit is being pooled trough one of these beds, it will act as a dart being pushed through a pipe and potential cuttings will accumulate around the BHA and in front of the bit. If the amount of accumulated cuttings is large enough they may plug around the BHA and bit, and jam the string. By reducing the tripping speed one will more easily be able to see if the hookload starts to increase more than expected when pooling out of the hole. In such case, circulation and reciprocation can then be engaged to clean out the cuttings and avoid potential stuck pipe scenarios. The two explanations provided here is an example of what drilling optimization is all about. A tradeoff where an optimal situation in one aspect of the operation are sacrificed to produce an overall higher performance.

#### Decreasing value and decreasing displacement

Figure 25 show that the values of all three curves are decreasing and the displacement between the curves is decreasing. The decreasing drilling hours per ft – blue curve, can be explained by an increase in ROP. The circulation and operational hours per ft (red and green curve) does not decrease by the same amount, they are decreasing more. This causes a decrease in displacement.

This leaves us with a positive development within all aspects of the operation. The ROP is increasing so one is drilling faster. The non-drilling circulation used is reduced and one is spending less static time. As long as the static time element is reduced more than the non-drilling circulation hours, we would see an increasing circulation to BRT hours ratio.

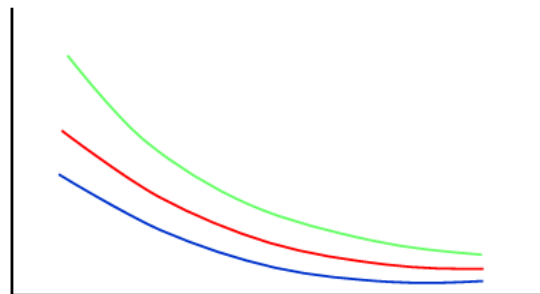


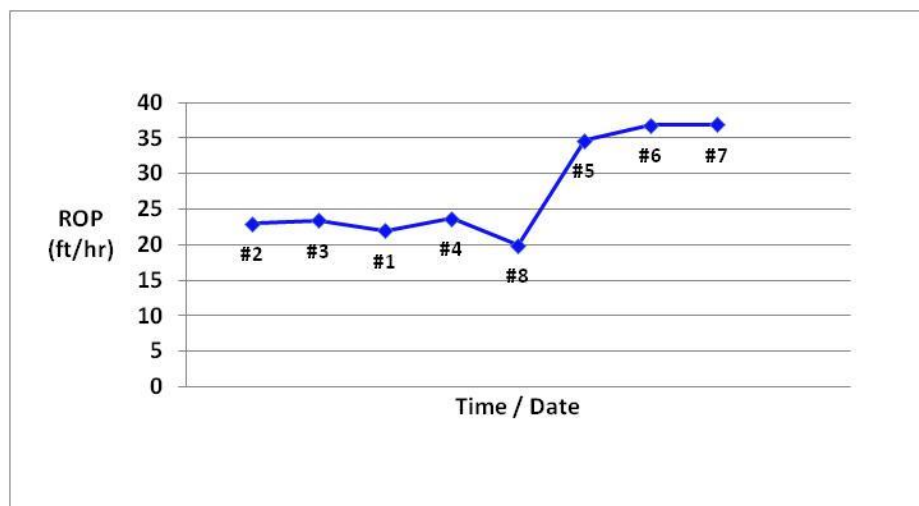
Figure 25 - Decreasing value and decreasing displacement  
Green curve represent the operational hours used per ft. Red curve circulation hours per ft and blue curve drilling hours per ft. Horizontal axis represent time section was drilled oldest to newest

## 4. Results

The following section presents the results from the performance study from the selected wells. The results are briefly described and will be further evaluated and debated in the discussion chapter of the thesis. The analysis has been carried out on each hole section size. The performance targets used are as described in the previous chapter. Each well represents each performance target with one value for each hole section. E.g. for well #1 only one ROP value will be used to represent the ROP in the 36” hole section and only one for the 26” section and so on. Based on the date which drilling of the relevant section started the targets for each hole section are presented chronologically from the first (oldest) to the last (youngest) section start date. Next to each performance target value, the well that the value comes from is displayed.

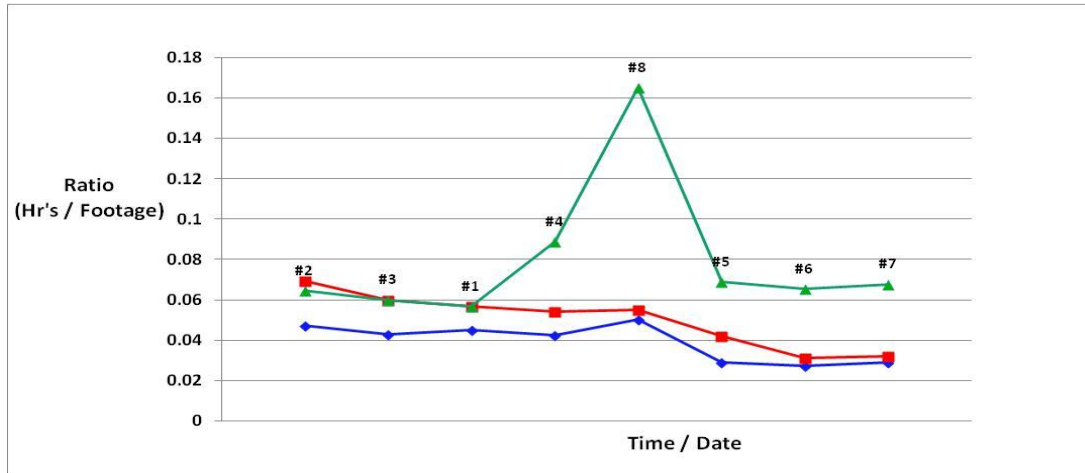
### 4.1. 36” Hole section

No NPT have been recorded in the 36” section.



Graph 1 - Average ROP through the 36” hole section for the 8 sample well’s chronologically arranged after section start date

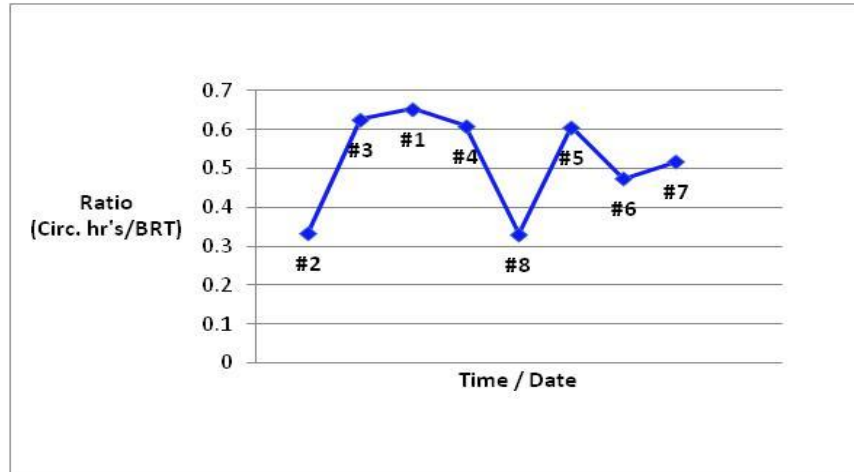
Graph 1 shows a stable ROP for the first 4 wells with an average ROP of 23 ft/hr. Then the ROP decreases by 15.7 % to 19.9 ft/hr followed by an increase of 57% from the baseline ROP of 23 ft/hr to a new baseline average of  $\approx 36$  ft/hr.



Graph 2 - Operational, Circulation & Drilling hours per ft for the 36" hole section.

Arranged from oldest to youngest section start date the green graph shows the operational hours, the blue curve the drilling hours and the red curve shows the circulation hours, all normalized on the footage drilled in the 36" hole section.

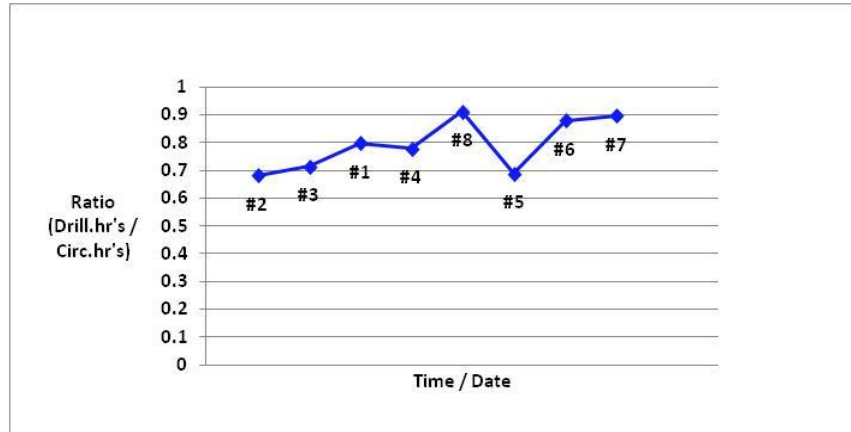
The graphs show how much drilling, operational and circulation time we are using per foot we drill. Considering the red and blue curve – circulation hrs and drilling hrs – we see that the spread is reducing as we move from left to right. From left to right, the first 4 wells show a reduction in displacement. For the last 4 wells small increase in displacement can be seen on well #5 but well #8, #6 & #7 are almost overlapping. In the same time we see that the operational hours (green) displacement from the circulation hrs (red) is almost zero for the first 3 wells but then peaks on well # 8 and stabilizes on a new higher baseline. The displacement between the operational and circulation hrs curves is increasing with time after the peak.



Graph 3 - Ratio between Circulation hours and BRT hours for the 36" hole section

Graph 3 shows the ratio of hours circulating to the total hours the BHA is below rotary table.

Well #2 and #8 have far lower ratios than the other wells. There seems to be a reducing trend and if we don't account for well #2 and #8 we can establish two averages. Well #3, #1 & #4 have an average of 0.61 (61%) and the last 3 wells 0.53 (53%) circulation time to BRT time. This is a  $\approx$  15 % reduction.

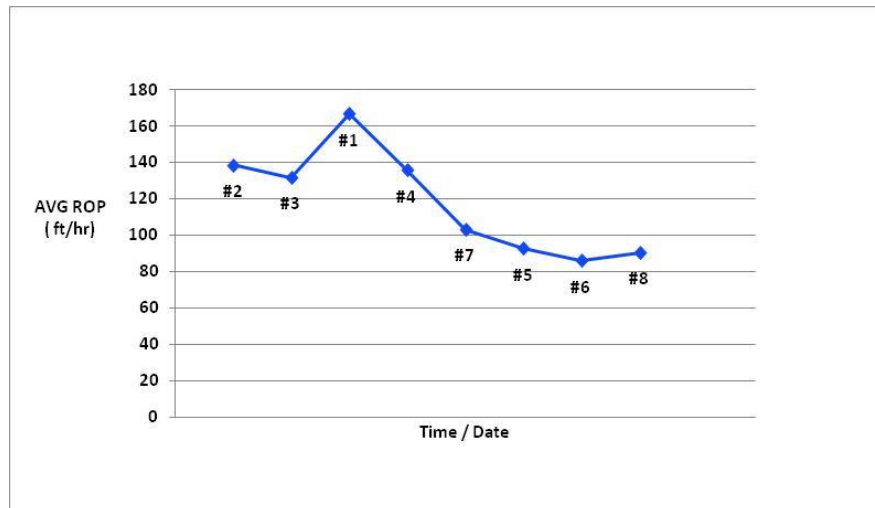


Graph 4 - Ratio between drilling hours and Circulation hours for the 36" hole section

Graph 4 shows an increasing trend. The 4 first well from left have a 0.7-0.8 ratio this is equivalent to  $\approx 70 - 80\%$  drilling time out of the total circulation time. The last 4 wells have a ratio of 0.9 where only well #5 has a ratio on 0.7. Excluding well #5, the drilling time out of the total circulation time is roughly 90%.

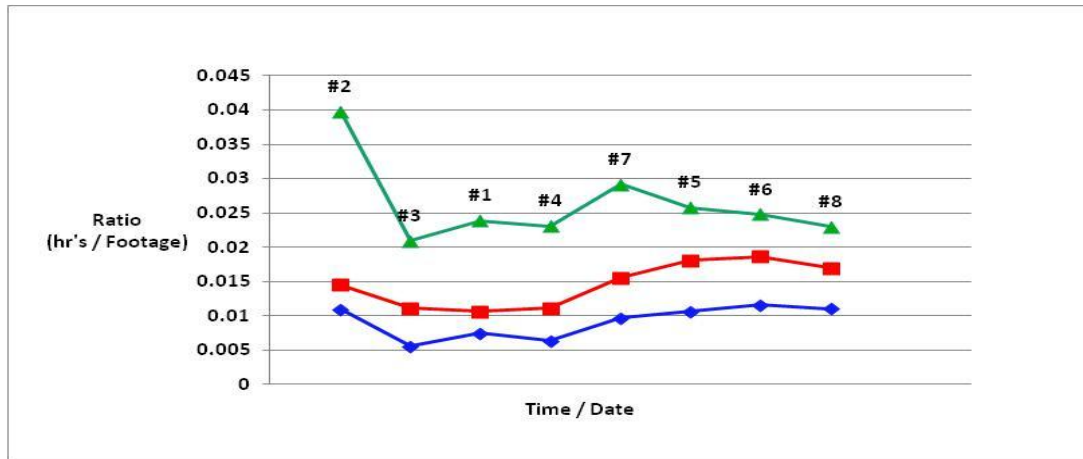
## 4.2. 26 "Hole section

No NPT have been recorded in the 26" section.



Graph 5 - Average ROP through the 26" hole section for the 8 sample well's chronologically arranged after section start date

The ROP show a decreasing trend. With the exception of well #1 (>160 ft/hr) the first wells (from left to right) show a ROP of approximately 140 ft/hr. Then the ROP decreases fast until it starts to stabilize on a ROP of  $\approx 90$  ft/hr for the last 3 wells.

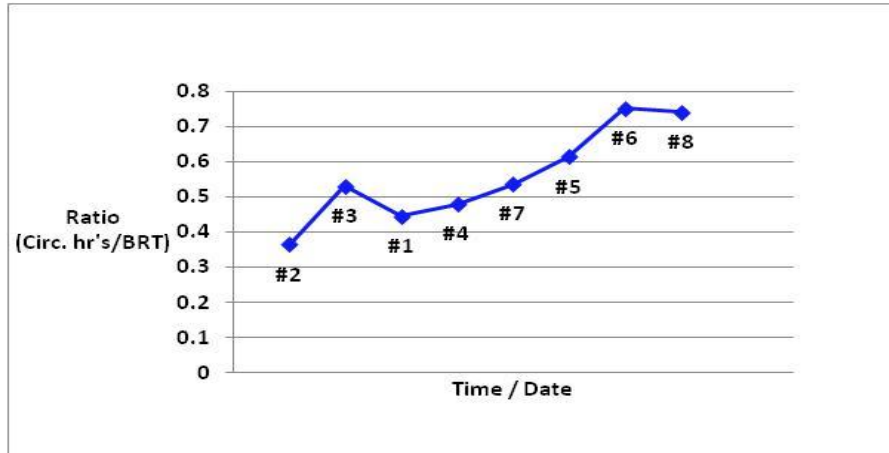


Graph 6 - Operational, Circulation & Drilling hours per ft for the 26" hole section.

Arranged from oldest to youngest section start date the green graph shows the operational hours, the blue curve the drilling hours and the red curve shows the circulation hours, all normalized on the footage drilled in the 26" hole section.

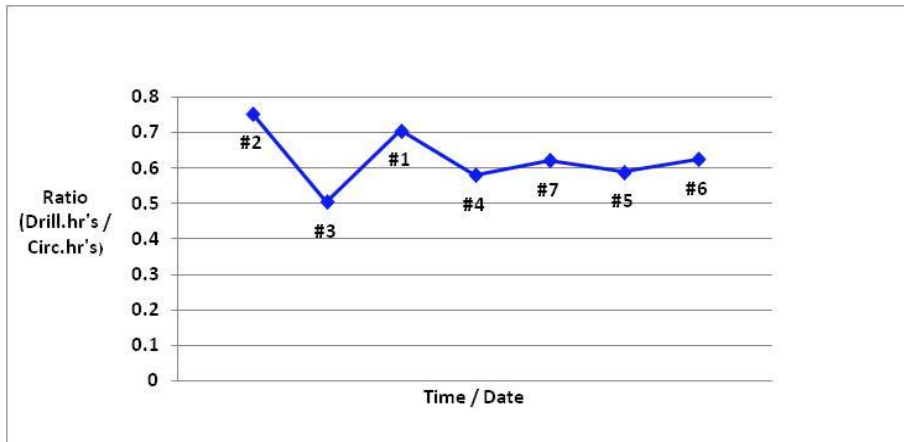
The graphs show how much drilling, operational and circulation time we are using per foot we drill. Considering the red and blue curve – circulation hrs and drilling hrs – the displacement between the curves are increasing with time. The average displacement considering the 2 first wells is 0.005 and for the last 2 average is 0.007, an increase in displacement. The Operational hours per/ft is not changing much if one doesn't consider well #2 and #7. The average of the first 4 (excl#2) is 0.023 hours/ft and for the last 4 (ex. #7) 0.025 hrs/ft. This is equivalent to  $\approx 8.5\%$  more operational hrs per ft for the 26" hole section on the last wells than the first wells. The operational hrs displacement in regard to the circulation and drilling hrs is decreasing with time.





Graph 7 - Graph showing the ratio between Circulation hours and BRT hours for the 26" hole section

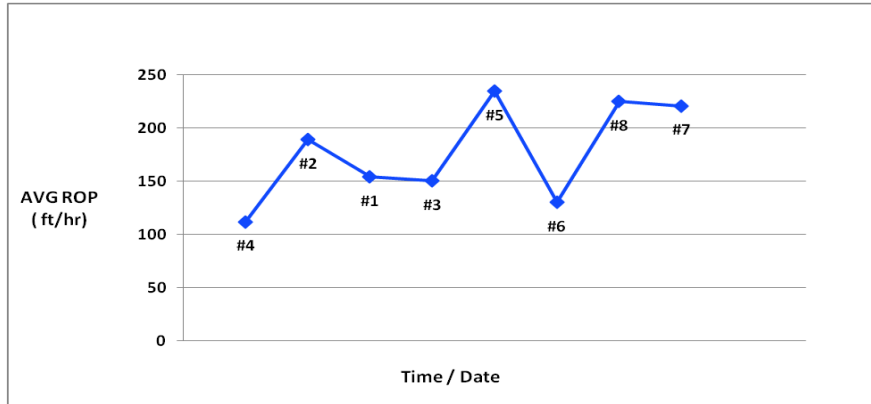
Graph 7 shows that the number of hrs that circulation is occurring among the total hours the BHA is below rotary table is increasing with time. The first 3 wells have ratio of approximately 0.45 ( $\approx 45\%$ ) and the last 2 wells ratio is  $\approx 0.75$  ( $\approx 75\%$ ). Roughly this is a  $\approx 65\%$  increase.



Graph 8 - Graph showing the ratio between drilling hours and Circulation hours for the 26" hole section

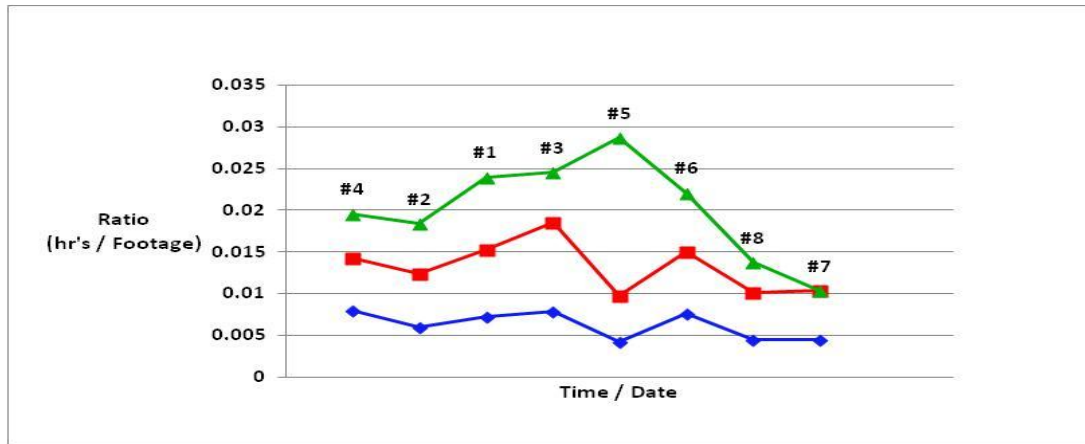
The number of drilling hours to circulation hours is fluctuating through the first 4 wells before it stabilizes on approximately ratio of  $0.6 \approx 60\%$ .

### 4.3. 17 ½" Hole section



Graph 9 - Average ROP through the 17 ½" hole section for the 8 sample well's chronologically arranged after section start date.

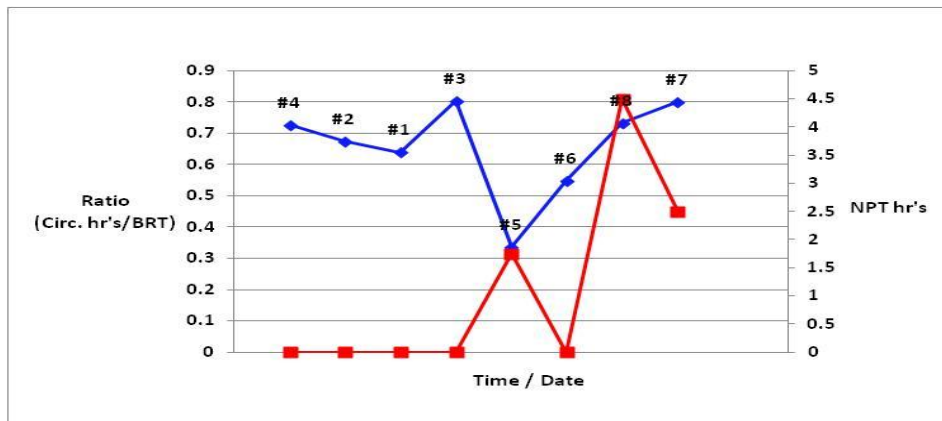
The ROP show a general increasing trend with time. The increase is in plateaus, the first plateau is on ≈150 ft/hr for well #1 and #3. The second plateau is within the last 4 wells, which is in the range 221 - 235 ft/hr if not considering the fall back on well #6. The second plateau is close to 50% higher than the first plateau.



Graph 10 - Operational, Circulation & Drilling hours per ft for the 17 ½ " hole section.

Arranged from oldest to youngest section start date the green graph shows the operational hours, the blue curve the drilling hours and the red curve shows the circulation hours, all normalized on the footage drilled in the 17 ½ hole section.

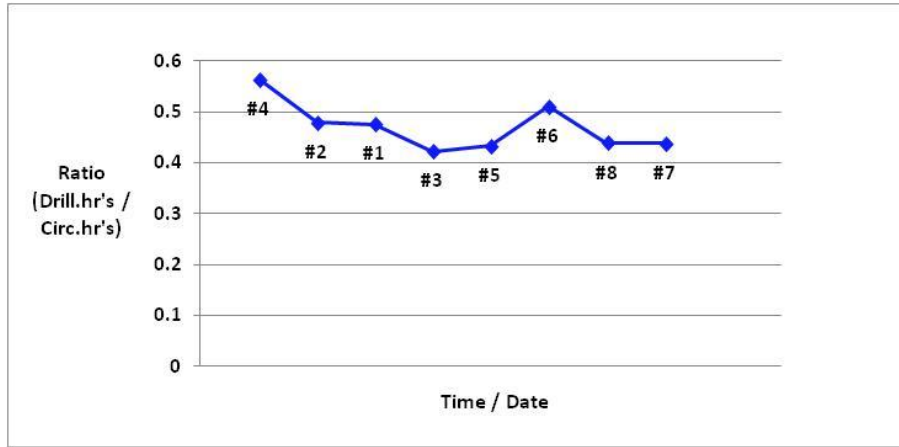
The graphs show how much drilling, operational and circulation time we are using per foot we drill. Considering the red and blue curve – circulation hrs and drilling hrs – the displacement between the curves seem to be constant with time except well #3 which have slightly higher circulation hours than one would expect if considering the curve trend. The absolute values of the curves still show a slight decrease with time. The Operational hours per ft is increasing to a maximum at well #5 and then drops consistently until it reaches a minimum on well #7. The displacement from the circulation hrs curve seems to be more or less constant on the first 4 wells before it decreases with time after a peak on well #5.



Graph 11 - Circulation to BRT hours ratio and NPT for the 17 ½ hole section

Blue curve shows ratio of circulation hours spent to BRT hours spent. Red curve NPT hours. Both curves chronologically arranged by time for the 17 ½ hole-section's start date.

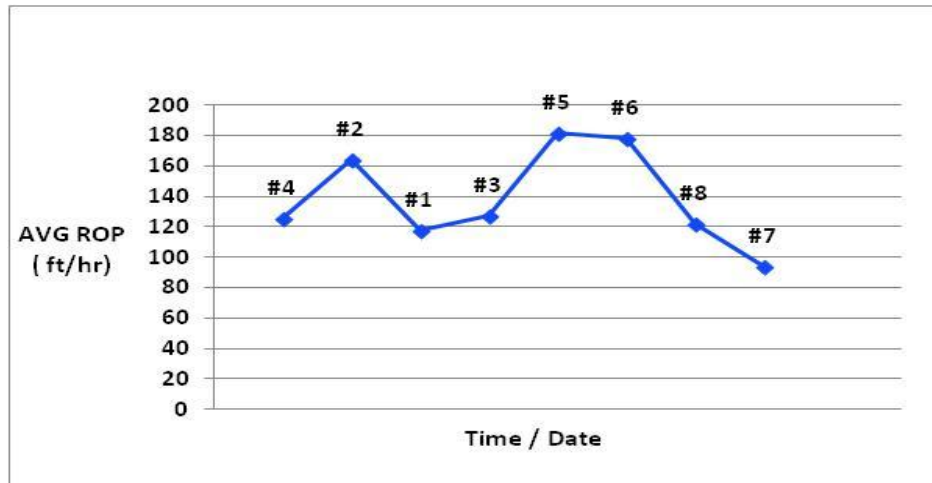
The circulation hrs/BRT hrs ratio is fluctuating in a range of 0.65 – 0.8 (65 – 80 %) through the first 4 well's. Well #3 has the highest ratio of 0.8 (80%). After the 4 first wells, in well #5, the ratio drops dramatically to just above 0.3 (30%). At the same time the NPT curve spikes. After the drop on well #5 the ratio increases significant with time, until it again reaches a ratio of 0.8 (80%) on well #7. NPT is also present on well #7 and #8 but it does not seem to have an impact on either the BRT or the circulation hrs, potentially they are equally affected.



Graph 12 - Graph showing the ratio between drilling hours and Circulation hours for the 17 ½ hole section

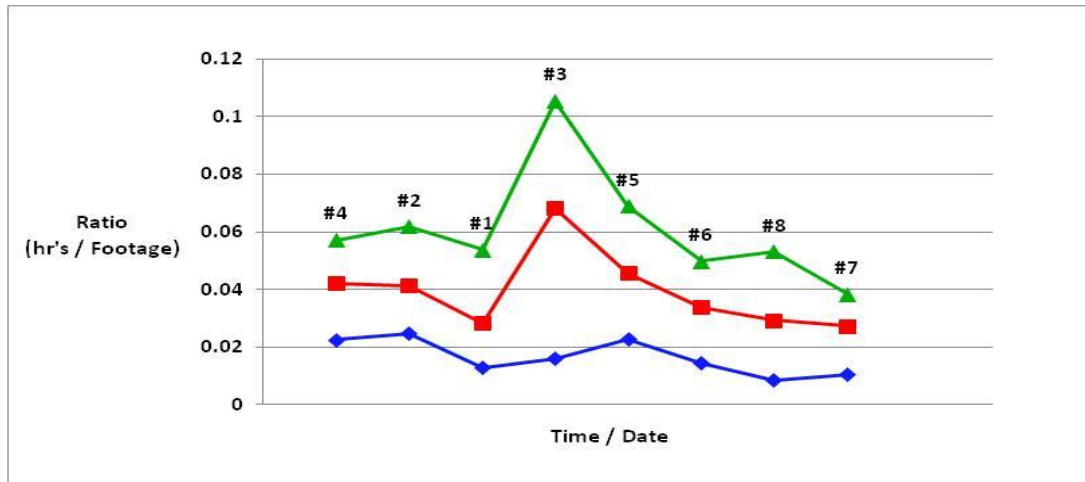
The drilling hours to Circulation hours ratio are showing a decreasing trend. In the first well the ratio is 0.56 (56%) and for the last 2 wells it is 0.43 (43 %). The best fit linear relationship for the curve suggests a decrease in the ratio of 0.012 for each new well.

#### 4.4. 12 ¼" Hole section



Graph 13 - Average ROP through the 12 ¼" hole section for the 8 sample well's chronologically arranged after section start date.

The ROP in this section is in a range from 90 to 180 ft/hr. For the first 4 wells the ROP is approximately 120 ft/hr with the exception of well #2 which generates a spike of  $\approx 160$  ft/hr. For the last 4 wells the variation is larger, but here we find a trend with decreasing ROP in time.

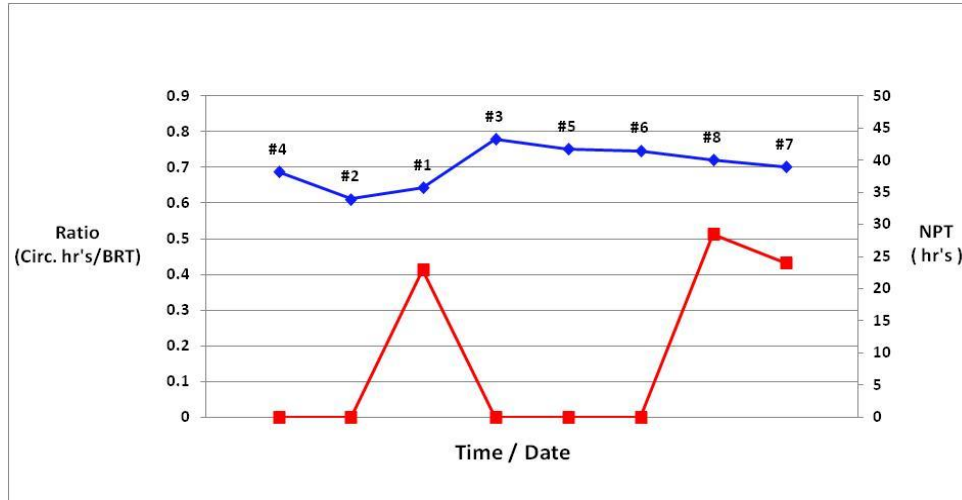


Graph 14 - Operational, Circulation & Drilling hours per ft for the 12 1/4" hole section

Arranged from oldest to youngest section start date the green graph shows the operational hours, the blue curve the drilling hours and the red curve shows the circulation hours, all normalized on the footage drilled in the 12 1/4" hole section.

All three curves are following more or less the same trend. The displacement between the green and red curve (operational and circ. hrs) shows a general decrease with time. The average displacement for the 3 first curves is 0.008 hr/ft and the average from the last 5 wells is 0.0043 hr/ft.

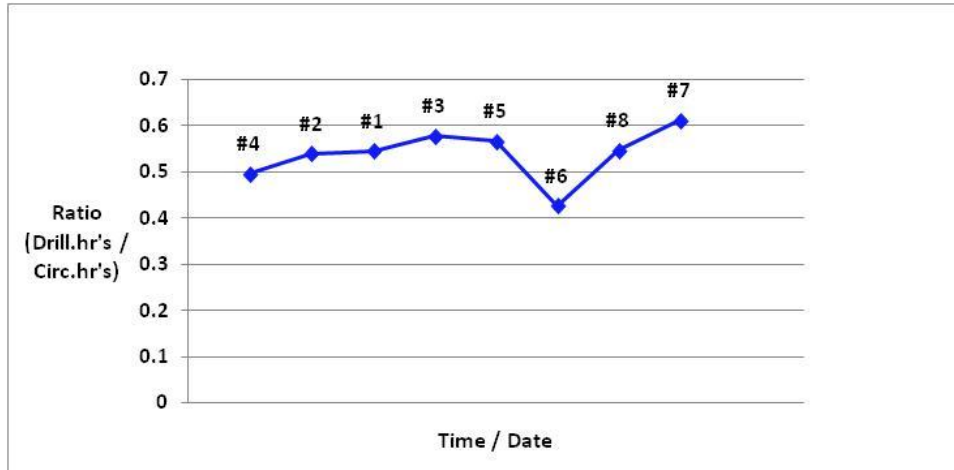
The red-blue curves (circulation and drilling hours) have a fluctuating displacement with time. No apparent trend in displacement, decrease or increase can be established.



Graph 15 - Circulation to BRT hours ratio in the 12 ¼" hole section

Blue curve shows the ratio of circulation hours spent to BRT hours spent. Red curve show NPT hours. Both curves chronologically arranged by time for the 12 ¼" hole section s start date.

The number of circulation hours to BRT hours has an increasing trend in the 4 first well's and a clear decreasing trend through the last 4 wells. If comparing the average ratio for the 4 first wells: 0.68 (68%) with the last 4 wells: 0.73 (73%), we see that there is a slight increase between the batches. There is recorded NPT on well #1, #8 and #7, this does however not seem to affect either there BRT or circulation hrs. Potentially they are equally affected.



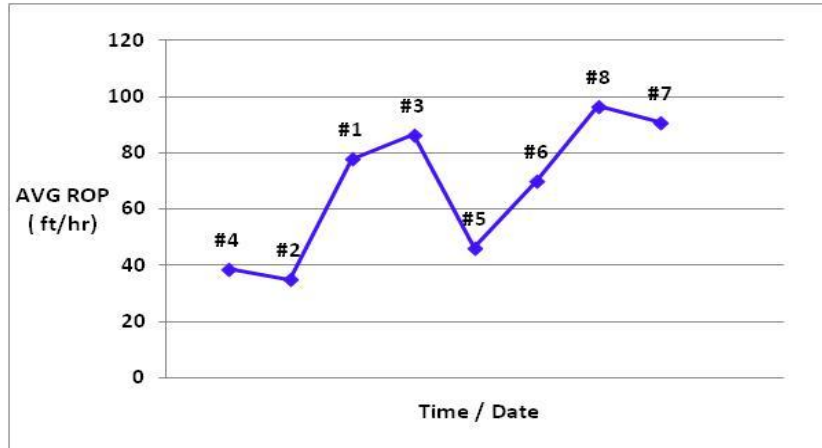
Graph 16 - Graph showing the ratio between drilling hours and Circulation hours for the 12 ¼" hole section

The drilling hours to circulation hours ratio shows a positive trend. With the exception of well #6 there is a clear increase. Less time is spent on circulation when not drilling. The first well has just below 0.5 (50%) drilling time and the last well more than 0.6 (60%) drilling time. The ratio decreased to 0.42 (42 %) on well # 6, with this exception the increase in almost linear in time.



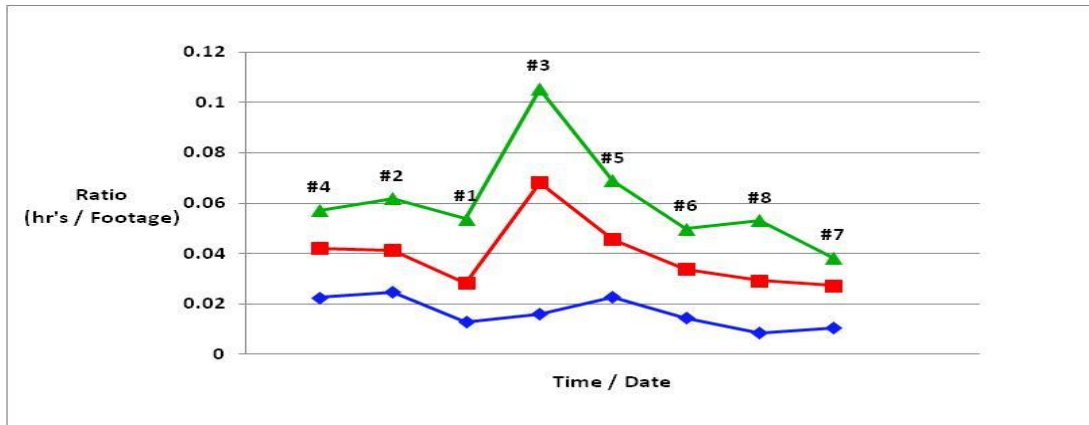
#### 4.5. 8 ½" Hole section

No NPT have been recorded in the 8 ½" section.



Graph 17 - Average ROP through the 8 ½" hole section for the 8 sample well's chronologically arranged after section start date.

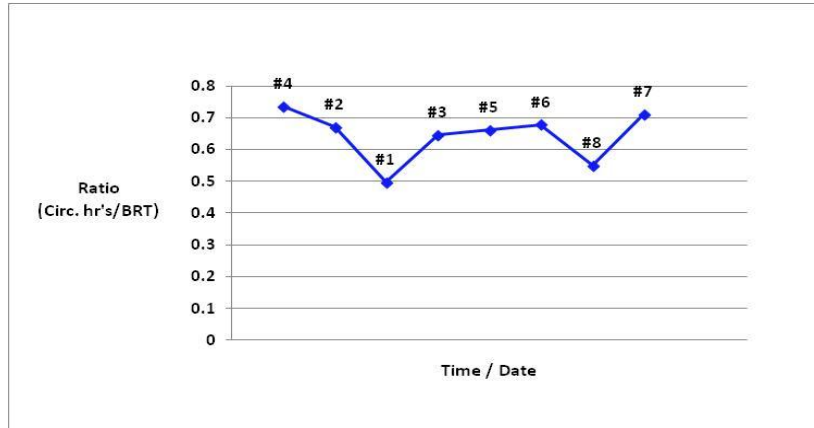
The first 4 wells, batch 1, are showing an increasing trend with time. This is also the case for the last 4 wells, batch 2. The ROP in the first well in batch 1 - #4 is 38 ft/hr. The last well in batch 1, well #7, have a ROP of 86 ft/hr, this corresponds to a 126 % increase. If considering the second batch, the first well (#5) is drilled with 46 ft/hr and the last well is drilled with a ROP of 91 ft/hr, which corresponds to a 98% increase in ROP. Considering all wells together and applying the best linear-relationship, the ROP increases by 7.3 ft/hr for each new well drilled. The general trend in the plot is an increasing ROP.



Graph 18 - Operational, circulation & Drilling hours per ft for the 8 ½" hole section.

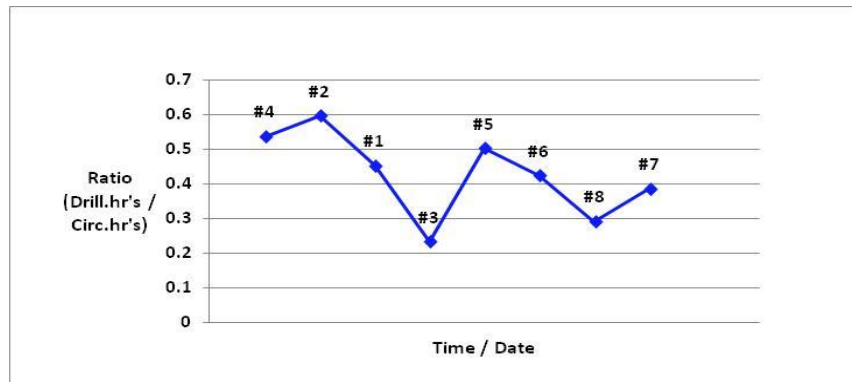
Arranged from oldest to youngest section start date the green graph shows the operational hours, the blue curve the drilling hours and the red curve shows the circulation hours, all normalized on the footage drilled in the 8 ½" hole section.

There are some variations but the general trend is that the absolute value of the curves is decreasing with time. The displacement for the first 4 wells, between the operational hours and circulation hour curves, is increasing. This can be seen when looking at the displacement on well #4 which is 0.015 hr/ft and compare it to the displacement on well #3; 0.037 hr/ft. On the last 4 wells the displacement is decreasing from 0.023 hr/ft on well #5 to 0.011 hr/ft on well #7. The displacement between the circulation and drilling hour curves does not show the same pattern. Except for the large increase in displacement on well #3 and partly #5 the displacement fluctuates between 0.016 - 0.020 hrs/ft with no consistent trend.



Graph 19 - Graph showing the ratio between Circulation hours and BRT hours for the 8 ½ " hole section

The circulation hours to BRT hour's ratio does show some variations but in general does not change much. Slightly lower values can be observed on well # 1 and #8. A linear relationship suggests a decrease in the ratio of 0.0025 for each well with time. This is a very small value that only makes up  $\approx 0.4\%$  of the first well (#4) Circulation / BRT time ratio.



Graph 20 - Graph showing the ratio between drilling hours and Circulation hours for the 8 ½" hole section

Graph 20 shows a decreasing trend. When considering all the wells, the application of a linear relationship suggests a decrease in the ratio of 0.029 for each new well. When considering the first 4 wells separately the same linear relationship suggest a decrease in the ratio of 0.11 for each new well. When separately considering the last 4 wells a linear relationship suggest a

decrease in ratio of 0.05 for each new well. The drilling / circulation time ratio is in the range 0.55 – 0.6 (55-60%) for the first 2 wells (#4 and #2) and 0.3-0.38 (30-38%) for the last 2 wells. These results show that there is more non drilling circulation hours recorded in the newest wells compared to the old ones.

#### 4.6. The value of the Total Improvement in an Average well

In an attempt to generalize the study an average well has been designed. The well has the same trajectory – Build & Hold, as the majority of the sample wells. The section lengths are averages of 7 of the 8 sample wells. Well #7 was left out because it has a different trajectory. The 8.5” horizontal section is much longer than it is in the rest of the wells. Figure 18 & 19 confirms the difference in well trajectory. The well is assumed to be drilled in the same formations and with the same rig.

The aim of this study is to try to measure the effect of drilling optimization. The study therefore focuses on the phase of well construction where drilling occurs. Based on this it was decided to use the BRT hours/ft parameter to reflect total drilling operation time and not include other operations like casing running etc. BRT hours has generally less fluctuations than the operational hours. It shows the hours from when the equipment goes below rotary table, finish drilling the section and is back above the rotary table. It is a good measure of the total drilling time.

One could argue that the operational hours is more suitable for reflecting total time, since it includes the time used on drill floor to initialize (pre) and read the tool memory data (post). The justification of the selected approach is that there exists an inconsistency related to when this time is measured; both start and end. This will be elaborated further in the discussion. Although there are some uncertainties related to all the times used, they were considered smaller for the BRT hours, thereby favoring the BRT / ft measurements.

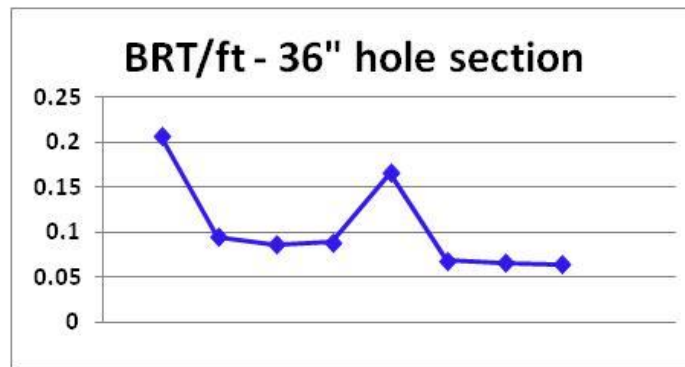
For each hole section 4 averages are calculated:

- Average BRT/ft for the 4 first wells (batch 1)
- Average BRT/ft for the 4 last wells (batch 2)
- Average BRT/ft for the 3 closest measurements from the 4 first wells (batch 1)
- Average BRT/ft for the 3 closest measurements from the 4 last wells (batch 2)

The last 2 is used to remove the extremities. This is believed to produce a more representative estimate of the time usage in the average well. The calculated BRT/ft averages from each hole section was used to calculate the BRT hours used to drill each section of the average well.

Finally the time consumption for each section was added up to generate the total BRT hours used to drill the average well. Based on the number of days (hours) that was saved and an assumed rig spreadrate of 900 000 USD / day a theoretical value of the improvement was calculated. The following section shows the results.

#### 4.6.1. Hole section Averages & Improvement Calculations

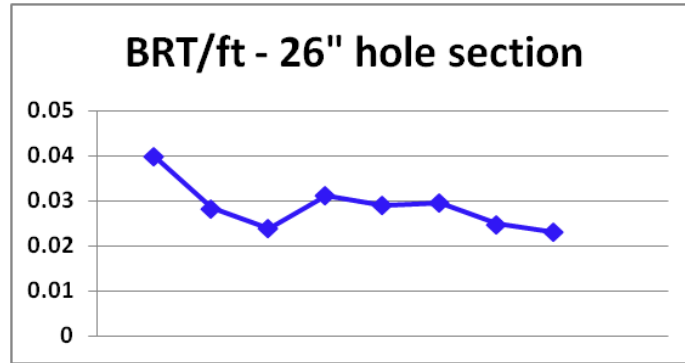


Graph 21 - The development of BRT hrs/ft chronological arranged in time for the 36" hole section

Average Batch 1	0.119	Closest 3 Average Batch 1	0.090
Average Batch 2	0.091	Closest 3 Average Batch 2	0.066
Improvement	0.237	Improvement	0.266
<b>Percentage improvement</b>	<b>23.7</b>	<b>Percentage improvement</b>	<b>26.6</b>

Table 3 - The calculated BRT hrs/ft averages and percentage improvement for the 36" hole section.

Graph 21 shows that the Below Rotary Table Hours / ft decrease with time. The hours used to finish the 36" hole section starts on  $\approx 0.21$  hrs/ft for the first well and decreases to a value of 0.065 hrs/ft for last well. Table 3 shows that there is a 23.7 % improvement in the average BRT hrs/ft from batch 1 to batch 2 when the average is calculated based on the results from all the wells in each batch. It also shows that if the average is calculated based on the 3 closest BRT hrs/ft values the improvement from batch 1 to batch 2 increases to 26.6 %. The most reasonable claim is to say that the time to drill the 36" hole section in the average well is reduced by 26.6 %.



Graph 22 - The development of BRT hrs/ft chronological arranged in time for the 26" hole section.

Average Batch 1	0.031	Closest 3 Average Batch 1	0.028
Average Batch 2	0.027	Closest 3 Average Batch 2	0.026
Improvement	0.137	Improvement	0.079
<b>Percentage improvement</b>	<b>13.7</b>	<b>Percentage improvement</b>	<b>7.9</b>

Table 4 - The calculated BRT hrs/ft averages and percentage improvement for the 26" hole section.

Graph 22 shows that the Below Rotary Table Hours / ft decrease with time. The hours used to finish the 26" hole section starts on  $\approx 0.04$  hrs/ft for the first well and decreases to a value of 0.022hrs/ft for last well. Table 4 shows that there is a 13.7 % improvement in the average BRT hrs/ft from batch 1 to batch 2 when the average is calculated based on the results from all the wells in each batch. It also shows that if the average is calculated based on the 3 closest BRT hrs/ft values the improvement from batch 1 to batch 2 increases to 7.9 %. The most reasonable claim is to say that the time to drill the 26" hole section in the average well is reduced by 7.9 %.



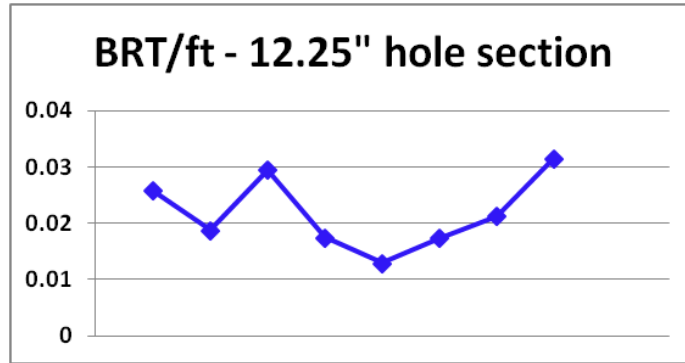
Graph 23 - The development of BRT hrs/ft chronological arranged in time for the 17 ½ "hole section.

Average Batch 1	0.021	Closest 3 Average Batch 1	0.020
Average Batch 2	0.021	Closest 3 Average Batch 2	0.018
Improvement	0.011	Improvement	0.103
<b>Percentage improvement</b>	<b>1.1</b>	<b>Percentage improvement</b>	<b>10.3</b>

Table 5 - The calculated BRT hrs/ft averages and percentage improvement for the 17½" hole section.

Graph 23 shows that the general trend in Below Rotary Table Hours / ft in a decrease with time. However the decrease is not as consistent as in the two previous sections. The hours used to finish the 17 ½" hole section starts on ≈0.022 hrs/ft for the first well and decreases to a value of 0.013 hrs/ft for last well. Table 5 shows that there is a 1.1 % improvement in the average BRT hrs/ft from batch 1 to batch 2 when the average is calculated based on the results from all the wells in each batch. It also shows that if the average is calculated based on the 3 closest BRT hrs/ft values the improvement from batch 1 to batch 2 increases to 10.3 %. The most reasonable claim is to say that the time to drill the 17 ½" hole section in the average well is reduced by 10.3 %.



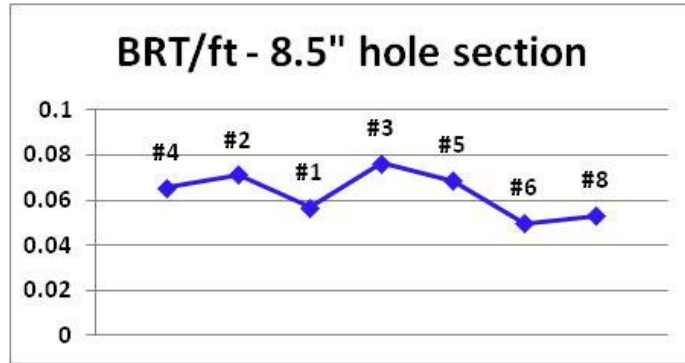


Graph 24 - The development of BRT hrs/ft chronological arranged in time for the 12 ¼"hole section

Average Batch 1	0.023	Closest 3 Average Batch 1	0.0219
Average Batch 2	0.021	Closest 3 Average Batch 2	0.0207
Improvement	0.091	Improvement	0.0571
<b>Percentage improvement</b>	<b>9.1</b>	<b>Percentage improvement</b>	<b>5.7</b>

Table 6 - calculated BRT hrs/ft averages and percentage improvement for the 12 ¼" hole section.

Graph 24 does not show a clear decreasing or increasing trend. The graph indicate that the Below Rotary Table Hours / ft is decreasing with time in the first Batch (first 4 values from left) and increases with time for the second batch. The hours used to finish the 12 ¼" hole section starts on  $\approx 0.025$  hrs/ft for the first well and decreases to a value of 0.013 hrs/ft for the fifth well (from left) before it increases to 0.032 hrs/ft on the last well. Table 6 shows that there is a 9.1 % improvement in the average BRT hrs/ft from batch 1 to batch 2 when the average is calculated based on the results from all the wells in each batch. It also shows that if the average is calculated based on the 3 closest BRT hrs/ft values the improvement from batch 1 to batch 2 is 5.7%. The most reasonable claim is to say that the time to drill the 12 ¼" hole section in the average well is reduced by 5.7 %.



Graph 25 - The development of BRT hrs/ft chronological arranged in time for the 8 ½” hole section.

Average Batch 1	0.068	Closest 3 Average Batch 1	0.0712
Average Batch 2	0.053	Closest 3 Average Batch 2	0.0471
Improvement	0.223	Improvement	0.3380
<b>Percentage improvement</b>	<b>22.3</b>	<b>Percentage improvement</b>	<b>33.8</b>

Table 7 - The calculated BRT hrs/ft averages and percentage improvement for the 8 ½” hole section.

Graph 25 shows that the Below Rotary Table Hours / ft decrease with time. The hours used to finish the 8 ½” hole section starts on  $\approx 0.065$  hrs/ft for the first well and decreases to a value of 0.038 hrs/ft for last well. Table 7 shows that there is a 22.3 % improvement in the average BRT hrs/ft from batch 1 to batch 2 when the average is calculated based on the results from all the wells in each batch. It also shows that if the average is calculated based on the 3 closest BRT hrs/ft values the improvement from batch 1 to batch 2 increases to 33.8 %. The most reasonable claim is to say that the time to drill the 8 ½” hole section in the average well is reduced by 33.8 %.

#### 4.6.2. Total Time Savings & Estimated Value

**BRT/ft - Average - Batch 1**

Section	BRT_HRS	Start	End	Footage	Max - Inc	BRT /ft
36	26.8733407	423	658	225	0	0.119
26	29.0626477	648	1592	944	0	0.031
17.5	144.043761	1592	8432	6840	40	0.021
12.25	135.434822	5432	11348	5916	45	0.023
8.5	89.505056	11348	12672	1324	45	0.068
<b>Sum</b>	<b>424.9196</b>					

**BRT/ft - Average - Batch 2**

Section	BRT_HRS	Start	End	Footage	Max - Inc	BRT /ft
36	20.4999999	423	658	225	0	0.091
26	25.0865916	648	1592	944	0	0.027
17.5	142.441558	1592	8432	6840	40	0.021
12.25	123.130627	5432	11348	5916	45	0.021
8.5	69.5611341	11348	12672	1324	45	0.053
<b>Sum</b>	<b>380.7199</b>					

**BRT/ft - Closest 3 Average - Batch 1**

Section	BRT_HRS	Start	End	Footage	Max - Inc	BRT /ft
36	20.3311209	423	658	225	0	0.090
26	26.2339781	648	1592	944	0	0.028
17.5	137.378651	1592	8432	6840	40	0.020
12.25	129.57953	5432	11348	5916	45	0.022
8.5	94.2352437	11348	12672	1324	45	0.071
<b>Sum</b>	<b>407.7585</b>					

**BRT/ft - Closes 3 Average - Batch 2**

Section	BRT_HRS	Start	End	Footage	Max - Inc	BRT /ft
36	14.9166665	423	658	225	0	0.066
26	24.1622142	648	1592	944	0	0.026
17.5	123.264796	1592	8432	6840	40	0.018
12.25	122.174067	5432	11348	5916	45	0.021
8.5	62.3838139	11348	12672	1324	45	0.047
<b>Sum</b>	<b>346.9016</b>					

Table 8 - The calculated total BRT hours for each hole section and the total average well BRT hours based on the 4 different averages.

Table 8 shows the calculations that were made to generate the theoretical BRT hours to drill the average well. The table show 4 blocks with the same calculations. As indicated in each block heading, the block contains the calculations made based on 1 of the 4 average calculations. The governing average BRT hrs/ft calculation method in each block produces a BRT hrs/ft value for each hole section. This value is multiplied with the length of this section in the average well. This generates the theoretical BRT hours needed to construct each section. The BRT hours are summed to generate the total BRT time used to drill the average well. This number is highlighted in red in each table block. The total BRT hours from the 4 average calculations is then combined in 4 different ways to generate the theoretical time savings between batch 1 and batch 2.

Table 9 show how many hours and days are saved on drilling the average well for different combinations of the average BRT hrs/ft values that was calculated. The rig spread rate is assumed to be 900 000 USD/ day and 1 USD = 6 NOK. The most reasonable comparison is, as suggested in the introduction of this chapter, when removing the extreme values and averaging based on the 3 closest values in each batch. In this case, the time saved when drilling the average well with batch 2 drilling efficiency / performance, a theoretical time saving of 2.54 days is generated.

<b>Comparison</b>	<b>Difference (hr's)</b>	<b>Difference (Day's)</b>	<b>Cost Savings (USD)</b>	<b>Cost Savings (NOK)</b>
<b>Average : Batch 1 v.s Batch 2</b>	44.20	1.84	\$ 1 657 489	kr 9 944 936
<b>Average : Closest 3 - Batch 1 v.s Closest 3 - Batch 2</b>	60.86	2.54	\$ 2 282 136	kr 13 692 817
<b>Average : Batch 1 v.s Closest 3 - Batch 2</b>	78.02	3.25	\$ 2 925 678	kr 17 554 066
<b>Average: Closest 3 - Batch 1 v.s Batch 2</b>	27.04	1.13	\$ 1 013 948	kr 6 083 688

Table 9 - The hours and day's saved for different combinations of the 4 different averages of BRT/ft calculated for each hole section and its related cost saving for the average well

## 5. Discussion

### 5.1. The effect of Batch drilling

The effect of batch drilling suggests that due to the gained experience one get by performing the same operation / drilling the same section repeatedly, one will naturally improve the efficiency and performance of the operation. In this case, the same operations are performed and the well design is more or less the same. The batch effect should then be seen as a continuous improvement for each new well drilled.

With respect to ROP this improvement should give a higher ROP. The drilling, circulation and operational hours used per length unit should decrease, as long as no other events influence the parameters.

The displacement between the circulation hours and operational hours ratios should ideally decrease. The same behaviors would be preferred for the displacement between the drilling hours and circulation hours ratio. However, this also need to be seen I relation to if the hours used per ft in each of these time categories is increasing or decreasing. Another thing worth mentioning is that when considering the displacement between these ratios one need to remember that they do not necessarily increase by the same factor for a given length of new formation drilled. Both the circulation hours and the operational hours may be improved but the improvement may not be apparent in regards to curve displacement. If one of the two is improved more than the other it may result in the displacement increasing between the curves, indicating that the efficiency is reducing when the overall time consumption is decreasing.

The drilling hours / circulation hours ratio reflects how much time is spent drilling of the total time spent circulating. In a perfect world this ratio is 1, and then there had been no circulation needed when not drilling. In the real world one need to clean the well and maintain hole stability etc so a value as close as possible to 1 is preferred. With respect to the batch effect the improvement one would expect to see is a continuous increase of the ratio as new wells are drilled.

The circulation hours / BRT hours ratio reflect how much time is spent circulating compared to the total time the BHA/Bit is Below Rotary Table. This ratio can never become 1 as we need to trip out the string after finish drilling. However, a continuous increase in the ratio for each new well drilled in combination with a reduction in the hours spent per ft could potentially be a batch effect.

The question arises to whether the batch improvement is a continuously improvement or if it first is seen when the wells in the second batch was started? In theory the batch effect is a continuous improvement for each repeated section / well. If the operation is just carried out as planned and no measures are taken before the next batch is started, then the effect of batch drilling would only be seen as a continuous increase in performance trough batch 1 and batch 2. The problem is that this will contribute to camouflages the identity of potential other performance contributors. The only way to separate drilling optimization is if there is seen a jump in performance from batch 1 to batch 2. In theory this does not coincide with principle of becoming better each time you perform a task and therefore is likely to be due to drilling optimization measures. However it may be argued that since the information and experience gathered trough the first batch is what enables drilling optimization, this could be considered an indirect batch effect. In further discussion, the batch effect is considered to be a source of improvement related to a continuous improvement for each new section / well drilled. Potential jumps in performance between the batches will be assumed be due to drilling optimization.

## 5.2. Hole Section Performance

### 5.2.1. 36" Hole section

For the first 5 wells the ROP is stable and then it increases by more than 50% after well # 8. There is clearly an improvement here; looking at the first 5 wells the ROP is more or less stable, suggesting that the reason for the increased ROP is due to an adjustment done after the first batch was drilled and the second batch started. The lessons learned notes from batch 1 described in chapter 3.3.3 confirms that data from batch 1 showed that it was possible to use higher flowrate than planned. A higher flowrate would allow a higher ROP while maintaining sufficient hole cleaning. Based on this information it seems natural to first start gradually increasing the flowrate and confirms stable conditions before also increasing the ROP. One scenario could be that well #8 was used to verify a higher flowrate rate, and when the flowrate was confirmed safe to use the ROP was increased in the next wells: #5, #6 and #7. The results do not oppose this theory and the procedure fits well with the definition of what drilling optimization concerns about. However, as mentioned, this is an example where one can argue that this an indirect batch. Regards of the classification, the improvement is clearly noticeable and the development improvement in ROP when averaging the 2 ROP plateaus on the curve was more than 61 %

Considering also the other measures, we see that the displacement between the drilling and circulation hours curves in graph 2 is decreasing. The decrease is apparent already from the first wells. The hours used per ft also show a decreasing trend with time, for the circulation hours curve, but starts first in batch 2 for the drilling hours curve. The continuous improvement could be a batch effect. The reduced drilling hours is due to the increase in ROP and as mentioned not to consider a batch effect. The time spent circulating when not drilling is being reduced. Circulation without drilling is typically initiated when there is a need to clean the well due to cuttings accumulation, reduce amounts of cuttings in the return flow because it causes high ECD or if one are concerned about hole conditions. The decrease then may be a indication that hole cleaning is evaluated to less of a concern than expected and that less cleanup circulation is needed. It may also be that the hole conditions proved more stable than initially expected and allowed for higher flowrate. Higher flowrate would contribute to better and faster hole cleaning.



These kinds of evaluations are usually not made by the driller and it then seem reasonable to suggest that the continuous improvement is rather an optimization effect than a batch effect.

The efficiency so far seems to be improving, but the operational hours per ft curve does not show the same positive trend. There is a good trend for the first 3 wells before it increases dramatically on well #4 and #8. After this it stabilizes on a higher level and on the last wells where one are spending more operational hours per ft than initially. The difference between operational hours and circulation hours is the static time element. This result confirms that this element has increased. Consider the BRT hours per ft curve in graph 21 in chapter 4.6.1. The interesting thing here is to see that except for the first well this curve has more or less the same trend as the operational hours per ft curve, but after the peak in operational hours on well #8 it stabilizes on a lower level than its initial level. The operational hours per ft stabilizes on a higher level. As mentioned earlier there exists an inconsistency in when the operational hours is measured. The stop time is considered to be when the tool memory data is downloaded. This may be done on drillfloor, in such case the operational hours and the BRT hours will be very similar, or after the tools are layed down on deck. Depending on the ongoing rig operations the tool data memory may not be downloaded before several hours after the tool was taken out of operation.

Considering the BRT hours per ft curve and the other performance targets it seem highly likely that this is the cause of the unexpected increase in operational hours used per ft. The Significant higher BRT hours on the first well may be due to some problems encountered after the tool memory data was downloaded on drillfloor. A problem encountered after the tool was downloaded while in the rotary table would result in an addition in BRT hours equal to the time it would take to fix the problem and pull the rest of the string out of the hole. However no such events have been reported. Another possibility is that it is a human error where the wrong above rotary time have been noted.

The drilling hours to circulation hours ratio are increasing with time which is as expected as the ROP is increasing and the hole cleaning seems to be improving. The circulation hours to BRT hours ratio have a general decreasing trend which in addition to the fact that the total BRT hours/ft is decreasing indicate more efficient drilling and hole cleaning.

The reports states that all the 36” hole sections was drilled trouble free. Taking this and the discussion so far into account it then seem likely that the improvement comes from the optimization of hole-cleaning and the hydraulics. Optimizing the hole-cleaning and hydraulics would remove the need for additional cleanup circulation time, allow higher ROP and explain the observed trend of the different time element curves. The increased use of operational hours does not fit with increased ROP and the BRT hrs/ft curve suggests that the discrepancy is a cause of a change in tool memory download procedure has occurred.

In total, the 36” hole section show a more efficient drilling operation. It is still not possible to confirm what improvements is due to drilling optimization or what is a batch effects. The only clear statements that can with certainty be made is that there is a clear improvement in drilling efficiency; reflected by a  $\approx 70\%$  reduction in Below Rotary Table Hours used when comparing the first to the last well drilled (graph 21).

### **5.2.2. 26” Hole section**

The ROP in the 26” hole section does with the exception of well #1 show a stable high ROP for the first 4 wells and then decreases in the last 4 wells. Looking at the drilling, circulation and operational hours per feet there is an increasing trend of drilling and circulation hrs per ft, and a decreasing trend of operational hours per ft. This is clear when looking at the last 4 wells while the first 4 wells are not as obvious. The circulation hours to BRT hours ratio clearly show an increasing trend. The drilling to circulation hours ration varies for the first 4 wells but stabilizes in the second batch; the last 4 wells.

The ROP is decreasing, this cause the drilling hours to increase because it takes more time to drill the same footage. The increase in drilling hours per ft also increases the circulation hours per ft, this is because we need to circulate while drilling. When considering the shape of these two curves the circulation hours per ft are increasing slightly more than the drilling hours per ft. This may indicate that there is also gained more non drilling circulation hours, not just the added drilling hours. However, the drilling hours to circulation hours ratio is at the same time stabilizing, opposing this suggestion.

The operational hours needed per ft is very high for the first well but decreases and show a slight increase until the first batch is finished (#4 is last well in batch 1). The first well in the second batch show a higher operational hours per ft value than well #4, but after this a steady decrease can be observed. The operational hours per ft curve is again a source of confusion. When looking at graph 22 one can observe that the BRT hours per ft curve is decreasing with time. As discussed in the 36” holesection performance chapter, also here does it seem to be an inconsistency related to when the tool memory were downloaded.

Considering the BRT hours per ft curve instead of the operational hours per ft curve one can conclude that there has been an improvement in efficiency. The Below rotary Hours used per ft on the first well in batch 1 is 0.04 hrs/ft and it reduces to 0.023 hrs/ft on the last well in batch 2. This is more than a 40% reduction.

It is not easy to identify the source of this improvement. The reduction in BRT hours used is apparent from the first well in batch 1. This fits well with the improvement being a batch effect. At the same time the results fit an optimization scenario where a tradeoff between ROP and drilling hours per ft is made. In addition to slightly increasing the non drilling circulation hours, good and stable hole conditions could be assured. This could allow faster tripping speed out of the hole and thereby explain the reduction in Below Rotary Table hours spent to drill the section. However the improvement in efficiency is apparent when looking on the total improvement in the use of BRT hours.

### **5.2.3. 17 ½” Hole section**

The ROP shows a stepwise increase. It stabilizes in both batches but the ROP stabilizes on a value  $\approx$  50% higher in the second batch, although well #6 shows a setback to 130 ft/hr the other 3 wells in batch 2 is fairly stable.

There is an increasing trend and displacement between the drilling, circulation and operational hrs per ft for the first 4 wells. With the exception of the displacement between the drilling and

circulation hours per ft, which only show small variations, a clear decreasing trend and displacement can be seen for the last 4 wells.

Well #5 shows a very clear spike in operational hrs per ft that may be explained by a NPT event adding on extra operational time. The NPT event is also reflected on the circulation to BRT hours ratio, but here as a drop. The spike in operational hours per ft and the drop in circulation to BRT hours ratio indicate that the NPT resulted in added static time. If the nature of the failure had also created additional circulation hours, the spike and drop severity would have been less. In addition, the drilling to circulation hours ratio is unaffected by the NPT and decreases with time. This also supports that NPT only caused additional static time.

The operational overview from well #1 reports that there was problems with packoff and stuck pipe when POOH, this may explain the increase in operational time that can be seen on well # 1 compared to well #2 and #4. Well # 3 was drilled after well #1, and displays an increase in both operational hours and circulation hours. There are no reported problems in this section, but the hole was washed and reamed while pooling out of hole. This is a normal preventive action if one suspect there is a potential for getting stuck, and explains why the both circulation time and total operational time is higher for well #3.

Well # 6 also show higher operational and circulation hours per ft than expected considering that there is no drilling problems reported. The operational overview reports the event of a failing topdrive which resulted in the string being reamed back to the shoe and the well left static until the topdrive was repaired. While reaming back there was circulation and while waiting the well was static. This explains why the operational and circulation hours are high in well #6. It should also be noted that no NPT is recorded for well #6 and that the ROP is significantly lower on this well than the other batch 2 wells. The failing topdrive seem to be a reasonable explanation for why the ROP is not maintained on a 220-230 ft/hr level in well #6.

In total the operational hours per ft reduces by almost 50 % from the first to the last well. Graph 23 also confirms that the BRT hours per ft are decreasing.

Finally, an overall comparison between batches 1 and 2 reveals an increased ROP, reduced drilling, circulation and operational time usage and a reduction in the amount of circulation hours

used outside drilling mode. There are some variations but considering the results from 2 first and last wells one can see that the 2 last wells are drilled more efficient than the first 2. Again, an identification of the source of improvement cannot confidently be made.

#### 5.2.4. 12¼" Hole section

With the exception of well #2 the ROP for the first 4 wells are stable around 120 ft/hr. For the first 2 wells in batch 2 (#5 and #6) the ROP starts out on 180 ft/hr before it starts gradually decreasing to a minimum of 90 ft/hr for the last well.

The drilling, circulation and operational hours per ft follow more or less the same curve trajectory. The BRT hours per ft curve (graph 24) and the operational hours per ft also follow the same trend, suggesting that there is consistency in when (where) the tool memory data was downloaded. The displacement between the curves does not change much. The increases and decreases of the curves follow the opposite response of the ROP. This is natural as long as no events that create additional time in usage occur. Graph 14 show that there is larger time usage on all 3 time curves for well # 1, especially the operational and circulation hours are large.

The circulation to BRT hours ratio decreases and then increases when moving from left to right through the first 4 wells. For the last 4 wells it shows a steady decreasing value.

The drilling to circulation hours ratio has with the exception of well # 6, a stable increase. The decrease in time usage on well #6 can be traced back to problems with the Pipe Racking system and that one additional day of WOW that was encountered (see operational overview 12 ¼" section well #6). In the 12 ¼" section there is generally a higher risk of a well control situation if the circulation is stopped, as this reduces the BHP. By the increase seen in both operational and circulation hours it is reason to believe that circulation was maintained as long as possible before the weather conditions required the well to be left static. This would explain the significantly lower drilling to circulation ratio on well #6 as no drilling hours would be recorded during these events.

The most obvious positive trend that may be observed in this section is the increase in drilling to circulation hours ratio, which shows almost consistent increase. It is spent less hours of non drilling circulation with time. This improves the drilling efficiency as long as it doesn't induce extra drilling problems such as consequences of bad hole cleaning. This also indicates that the circulation to BRT hours is a positive indicator since the drilling hours are implemented in the circulation hours. The other curves do actually indicate a worsening situation with time, with increased time per ft drilled and lower ROP.

However, if we see the section performance in relation to what kind of challenges they had to battle during the 12 ¼" section the results can be justified. Stringers, Packoff's, minor to severe losses were encountered and this way a concern in all the wells. 5 of 8 wells had to POOH due to drilling problems or failures. Well #1 and #4 had to POOH unexpectedly twice. In well # 6 surface equipment failed and the operation halted to WOW. In well #7 they battled so heavy losses that the well had to be sidetracked after performing a cement squeeze job. Taking this into consideration, the higher time usage and lower ROP makes more sense. Restricting the ROP would help to properly clean the hole and reduce the chances for getting into new packoff events, stabilizes ECD and the borehole stability. To indentify challenging downhole environment one need to evaluate the drilling parameters and look for indications of onset of unfavorable conditions, onset of packoff etc. Slowing down don't just allow better hole cleaning but also lowers the response time in terms of formation drilled and enhances the drilling optimization specialist's ability to respond.

The increase in the drilling to circulation hours ratio means that less time is spent with only circulation. In addition it was only recorded slight loss of circulation and only onset of packoff in the last well. Despite all the problems and challenges that were battled, these two elements are at least positive ones. Without being to conclusive, these 12 ¼" sections at least serve as a reminder that we can never 100% "know" what kind of challenges the subsurface will facilitate before we actually have drilled it.

### 5.2.5. 8 ½” Hole section

The ROP curve development show an increasing trend for both batches, the second batch having the largest ROP's. Well# 4, #2 and #5 have considerably lower ROP than the other wells. In well # 4 and #2 it was encountered hard formations. In well# 2 the progress was so low that the section was finished 212 ft shorter than planned. This explains the lower ROP in these two wells. Well #5 was also drilled with restricted ROP but the reason is not stated.

The circulation and operational hours per ft curves in graph 18 have increasing displacement through the first 4 wells and a decreasing displacement on the last 4 wells. This indicate that in the first batch the efficiency is not improving, rather the opposite. On the last 4 wells the displacement is decreasing with time while the absolute value is also decreasing. This reflects an increased efficiency as less hours of circulation is needed per ft.

All three curves in graph 18 show a decrease in time usage per ft in the second batch. The first batch has a more irregular pattern and well # 3 show significantly higher values for all three curves, compared to the first three wells. In well # 3 it was performed a Cut & Slip of drilling line in the middle of the section. This causes additional operational and circulation hours and explains why these two curves have a large increase compared to the drilling hours used per ft in well #3.

The circulation to BRT hours ratio does not change much, it has a couple of drops but it is more or less stable around 70 %. Seen in relation to the circulation and operational hours per ft, this suggests that the time reduction is more or less equally affecting both circulation and operation hours used.

The drilling to Circulation hours has a decreasing trend. Since the ROP is increasing and the circulation hrs to BRT hours does not change much, this indicate that we are spending the same number of hours circulating but less time is spent drilling due to the increasing ROP.

It seems that even if they are able to drill faster they do not risk reducing the additional circulation hours. This is likely because this is the reservoir / target section and it will be very critical both in regards of production and completion to maintain a clean and stable hole.

Sometimes there is also a requirement to take cuttings samples every 3 -10 ft in the reservoir, this also limits the ROP.

In total the results show a positive development when considering the time spent. If considering an average, all time usage curves are lower for the last 3 wells than the first 3 wells. The ROP is also showing an increasing trend and the circulation hours to BRT hours ratio is stable while we are spending less hrs drilling the well. The drilling efficiency has clearly been improved.

### **5.3. Reporting structure and challenges**

#### **5.3.1. Level of detail**

As the discussion on each hole section performance shows it is almost impossible to identify the effect of Chen's drilling optimization as defined in the introduction of this thesis. To do so one needs very detailed information on what measures and actions that was taken. The level of detail observed in the reports studied in this thesis was in general not high or consistent enough to make a quantification of the effect. This creates an uncertainty element related to identifying or explaining measures or performance target development. If there is a large level of detail in a report this allow for identification of the root cause of discrepancies. One can confirm if the discrepancy is due to a lower performance or a direct measure taken to mitigate a problem. If the detail level is too low one will not be able to identify reasons for potential discrepancies and may assume that no measures were taken. This may easily cause unfavorable or an incorrect picture of the drilling optimization service or where the improvement potential for the operation actually is situated. This has been the case in this study and as a result, the discussion has become more general and moves towards evaluating trends and averages.

One point worth mentioning is that this may not be a bad approach, because it reflects the total or real drilling efficiency seen from an economical point of view. For the oil company the optimization doesn't add real value before it actually reduced the time used to drill the well thereby reducing their costs or losses.



### 5.3.2. Consistent measurements

Another challenge is the uncertainty related to the operational hours reported. As mentioned and shown in the discussion, it may occur that the end time noted is reported after the tools have been layed down on pipedeck instead of when they come out of the rotary table. This may create a difference of up to several hours that produces an incorrect picture of the operation efficiency.

A similar issue is related to measuring the BRT – Below Rotary Table hours. Some starts counting from when the bit is below/above rotary. Others start when the BHA is below/above. Looking on one well this doesn't have a large impact, but when comparing wells it may create inconsistencies and again an incorrect impression of the situation. This creates an inconsistency that can be seen as a different value recorded for operational and BRT hours. In some cases it shows that the operational hours are larger than the BRT hours like when comparing the first 4 wells in graph 24 and 14. In other cases the operational hours are less than the BRT hours as when comparing the first 4 wells in graph 25 and 18. It is hard to say which one is more correct but in general the fluctuations are less for BRT hours than for operational hours and is why, as also elaborated in chapter 4.6, BRT hours have been used to reflect total time usage.

A solution for both these problems would be to incorporate a note in the handling procedures and specify that BRT is to be counted from bit or BHA is below rotary table. In addition a note should be added in a comment if the tools are layed down on deck before the tool memory data is downloaded.

### 5.3.3. Further work

The value of drilling optimization is not easy to study. This is because one never drill the same well twice. Even if wells are very similar, like the wells in this study, the reference will be debatable. Nevertheless, it would be very interesting to be able to say more confidently something about the value of Drilling Optimization as per Chen's definition [4]. In relation to this it seems natural to involve statistics and probability.

If one could assure consistent reporting of the correct information, one would after a certain period of time have the possibility to use the information to generate a relation between the jobs performed by the drilling optimization specialist, time spent drilling the section and the number of drilling challenges and unfavorable events. The probability distribution of different unfavorable events could be established based on the number of occurrences of the event in a certain period of time or number of wells. These occurrences could further be separated into categories based upon what drilling optimization services that were used. Simulations could then be made on the probability of the event occurring. The value of the drilling optimization could then be displayed in terms of the difference in the probability of occurrence for different time consuming events, with and without drilling optimization specialist. Further, the probability for an event to occur depending on what formation it was drilled through, what hole size etc. could be made to broaden the analysis.

The reporting structure would need to be set up with an easy-to-use interface and allow for easy exportation of the data into spreadsheets and simulation software. The “extra” work for the personnel required to perform the reporting should be minimized to avoid the phenomenon “reluctance to change”.

## 5.4. Performance Study Reflections

As the discussion on hole section performance reflects; it is very hard even to identify who or what contributes to improved performance based on the information available for this study. So far the study has shown that there have been improvements in the efficiency, but this is seen mainly as total improvement, especially when considering the development between the batch 1 and batch 2. To further quantify the improvement related to specific services or actions then becomes an impossible task, and the value of drilling optimization as: *“a process that employs downhole and surface sensors, computer software, Measurements While Drilling (MWD) and experienced expert personnel – all dedicated to reduce drilling trouble time and increase drilling efficiency”* [4], is not possible to measure in this study. However, the total improvement in drilling efficiency can be measured. This will at least give an estimate of the total value the measures and actions in these wells have. The following discussion on The Value of the Average well elaborates on this value estimation.

## 5.5. The Average well

The absolute value for the operator company's point of view is generated first when they spend less time finishing the complete drilling operation with the same or better quality than they normally would do. The average well gathers the result from this study into one complete picture and show the difference in performance between batch 1 and batch 2. Based on the different average calculation methods (described in the introduction to the "the average well" result section) two different average values for the BRT hours per ft was calculated for each holesection, in each batch. Based on the lengths of each section of the average well and these averages, the total Below Rotary Table hours used to drill the average well was calculated. Four total BRT hours values was then generated, two from batch 1 and two from batch 2.

Table 10 shows that even with the least favorable combination 1.13 day's was saved in BRT hours on batch 2 compared to batch 1. The most reasonable combination gives 2.54 days saved and the most favorable one gives 3.25 day's saved. This is only on the drilling process, running casing, cementing and completions is not included. With the assumed rig spread rate of 900 000 USD / day, this equals a minimum savings of  $\approx 1$  MM USD, most reasonable:  $\approx 2.3$  MM USD and most favorable;  $\approx 2.9$  MM USD.

The least favorable value is calculated based on the average performance in each hole section among all the wells in each batch. This is called "least favorable" because it includes all extreme values. Some of these wells had large time additions due to WOW and surface equipment failing, this caused the BRT hours in certain sections to be significantly larger in some of the wells. These kind of events where present in both batches. They are not considered as something that can be affected by optimization and does create an unrighteous picture in the discussion on increased performance. Still even with these time elements included, batch 2 performance would finish drilling the average well 1.13 day's faster.

The most reasonable combination was considered to be when the extreme values were excluded. When analyzing samples of data it is accepted praxis to remove extremities, so to be consistent the 3 closest values was used in the calculations. As the results in table 9 shows, there 2.54 day's less time used using batch 2 performance.

The most favorable combination was obtained when the averages calculated from batch 1 was based on all 4 wells and batch 2 averages was calculated on the closest 3 values. This gave 3.25 day's less time used using batch 2 performance. This cannot be considered as a valid comparison as it include extremities in the first batch performance and not in the second batch facilitate a larger difference between the batches that favor batch 2 performance.

Based on these results from the average well, we see that there is generally a better drilling performance on the wells in the second batch and the most reasonable time saving is 2.54 days. By multiplying this number with the rig spreadrate of 900 000 USD, savings of 2.3 MM USD is generated.

The value of the total improvements that has taken place during drilling of these 2 batches can't directly be reflected by this number. This number is for the average well and will also serve as an average estimate. However, as an example, let's look back at Figure 6. The number of planned wells in 2012 is approximately 110. After 2012 it is assumed to follow a  $\approx 17\%$  increase in the number of wells needed to be drilled per year. A 17% increase results in an additional 18.7 wells. Assuming the time distribution for the well construction process shown in Figure 16, drilling will make up 25% of the total time usage. Table 8 shows that the time to drill the average well with batch 2 performance is 346.9 hours. If all 110 wells were drilled with batch 2 performances - 2.54 days faster (table 9), this would equal a time saving of 6694.6 hours (110 wells x 2.54 days x 24 hours). This is equivalent to the drilling time in 19.3 average (6694.6/346.9) wells. In terms of well total construction time, where drilling time make up  $\approx 25\%$  of the total, the time savings would be equivalent to 4.8 complete well constructions. So the time saved in only the drilling phase of the well would allow almost 5 extra wells to be drilled in the same period of time. This is of course only an estimate of what the time and cost improvement that can be achieved, but it clearly reflects that optimization does add value both in terms of drilling and cost efficiency.

## **5.6. The Contract Set-ups effect on Drilling Performance**

### **5.6.1. Standard Contracts Setup**

So far this study has shown that there is an improved drilling efficiency between the two batches. Tracing the improvement to a specific measure or action can't be done. The total improvement seen when using drilling optimization specialists, batch drilling and a performance focused organization, is reflected as a 2.54 day savings in drilling the average well. The last thing that not yet has been discussed is the contract set-up that these two batches was governed by, and if it could be related to the increased performance.

As in all business, prior to any services is performed, the terms and conditions of the agreement is settled in a contract. When the operator company has developed the scope of the work, the drilling service providers receive an Invitation To Tender – ITT. The drilling service contractors then receive the contract set-up and the job description. Each individual contractor then submits a response to this ITT and the operator decides who is awarded the contact. This is a time consuming process and I will not go into far details of how a “winner” is chosen, but such factors as price, HSE record, technology, competency, track-record/experience, organization etc, all come into play. However the general contract structure is of some interest when it comes to our discussion of the value of total improvement and optimization.

There are 4 main revenue generation structures that the drilling service contracts are based upon:

### **5.6.2. The Flat Rate Rental**

This is the “old” contact structure that descends from the early days of the oil industry. At this time the majority of the competency's was located in the operator companies and the contactors only supplied the equipment, much like a rental-car company provides you with all you need but you have to operate the car yourself. This contract provides a flat rate in the whole period the drilling package is mobilized, independently of how long the tools is below rotary, drilling etc, the total number of days the tools are occupied on the job ( the 16 days line in figure 27) is what generates revenue.

### **5.6.3. Standby Rate & Operational Rate**

The revenue is generated by a standby rate and an operational rate with some contracts also offering a bonus if the job is performed faster than planned. Based on days or hours there will be an agreed rate for standby and operation. This contracts are usually used for exploration well's where the scope of the job are more uncertain; meters to be drilled, length of section, etc is a lot harder to predefine than for production wells.

### **5.6.4. Standby Rate & Meter Rate**

Revenue is generated based on a standby rate and the amount of meters drilled, or in some cases circulating hours. A bonus may be included as an additional \$\$\$/ Meters drilled and based on the drilling performance time wise. This kind of contracts is normally used when the scope is very well predefined.

### **5.6.5. Pure Meter Rate - \$\$\$/Meter**

Here all the value for the drilling contractor is generated when drilling. These contracts are high risk - high impact contracts and is not very common.

### **5.6.6. Contracts Risk Distribution**

The contract setup described can be considered as the standard lay-out. Additional risk's and circumstances are always present and may be treated as own sections in the contract, usually related to the job scope level of detail. However, the fight is always how much risk the service providers is to hold, or are willing to take in regards to the success of the operation and thus revenue generation.

When the drilling service provider bids on a contract he need to have a clear understanding on what costs he is facing. Figure 26 illustrates a typical job and the related cost generation for a drilling service provider. A large part of the fixed cost is equipment depreciation but also such as

facilities, organization etc. The Variable cost only relates to cost that comes as a consequence of the tools being operational, repair and maintenance, consumption of parts etc.

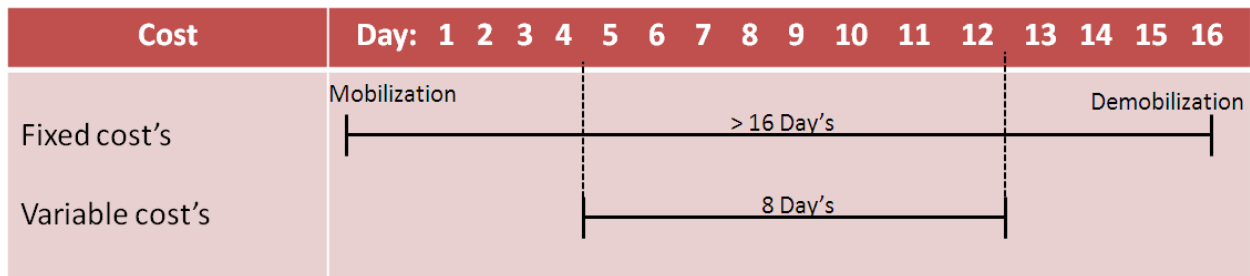


Figure 26 - Example of cost Generation for a drilling service contractor

Depending on the contract setup the revenue generation will be based on the activity or a combination of activities related to the operation. This is usually set up such that different amounts of revenue are generated in the different phases. As mentioned earlier the cost generation and work starts long before the drilling operation, and during the operation there is never 100% drilling time. So, the cost generation structure and the revenue generation structure are not the same and this is where the risk element becomes an important factor. Who is to hold the risk of operational success?

Figure 27 shows an example of the time consumption in the different phases of a drilling operation.

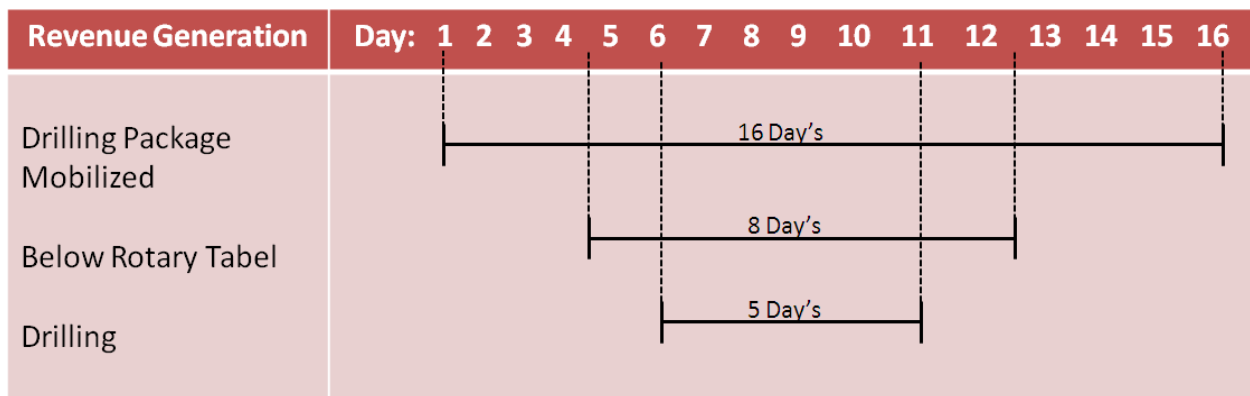


Figure 27 - Example of the main revenue generating phases for a drilling service contractor



If we go back to the different contact set-ups we can point out some interesting facts. On the flat rental rate the service provider is making his revenue based on how long the drilling package is in use. The level of success of the operation in the operators view does not influence the revenue; actually the longer and more inefficient the drilling operation becomes the more revenue is generated for the drilling service provider. This does not encourage increased performance, more the opposite, and the operator is bearing all the risk related to operational success.

On the far other side we have the meter / ft rate set-up. If we look at the examples of the different phases we see that the revenue now needs to be made on 5 day's instead of 16 days, less than a third of the time. If the price on this job was 30 000 USD the income would change from a daily amount of 1875 USD, to 5 days where the charge would be 6000 USD. In addition the service provider also holds the risk related to unexpected events like WOW, rig equipment failure, connection time etc. At the same time the fixed cost of the operation for the service provider is still related to the time from mobilization to demobilization. This possesses an additional risk because there is uncertainty to how large both the fixed and the variable cost of the job will be. This uncertainty is usually managed by an addition in price to account for some unexpected costs. But the competition in the market does not allow this amount to be nearly as large as it naturally would be, so the risk related to revenue remains high. The upside here is that if the section / well is drilled faster than the planned, the revenue is still the same. If this results in the drilling package being demobilized earlier this serves as a bonus because the drilling package now also can generate value on the saved days. In total this set-up requires the drilling service provider to take a far higher risk, because they now need to make his money on only 5 days and face the uncertainty related to how long the operation will take. If the topdrive fails and it takes 24 hrs to fix it, the extra fixed cost and variable costs is lost revenue. However, it also facilitates the opportunity to increase revenue. This kind of incentives put a high value on performance and encourages the service provider to perform at the absolutely top of their ability.

### 5.6.7. Incentive effects on Batch 1 and Batch 2 Performance

The 2 batches that have been drilled were on the same contract setup, but batch 1 was drilled without any performance incentives. On Batch 2 on the other hand, it was incorporated performance incentives affecting both the drilling service provider and the rig contractor.

It is interesting to see the difference in performance on the 2 batches in relation to this. Because the most reasonable comparison shows that the second batch performance numbers results in 2.54 days less drilling time on the average well. This is excluded the time it takes to run and cement the casing in place. Moving back to our discussion on the value of drilling optimization, the results may actually imply that the performance will to a large extent be governed by the contract structure. Except for the experiences gained from the first batch and the optimization that was made based on this information, the same service was supplied in all the wells. The difference between the two batches was the performance incentives and a higher performance is recorded for the wells affected by these incentives. This suggests that there is a strong relation between the contract set-up the service providers have to relate to and the performance they deliver. One could argue that the improved drilling efficiency had to be a batch effect since all the other services provided was the same, and that the optimization did not add any value. This would however suggest that performance incentives are useless and do not take into account the measures that were described by the coordinators in the chapter 3.3 - “Operational Planning and Measures”: Focus on performance, all three parties (service provider, operator and rig contractor) engaging in strong teamwork, clear communication and adoption of targets and experiences, focus on standardizing the operations and at last: all three parties was “pulling” in the same direction. In addition it would suggest that the improvements the drilling optimization specialist did, as the majority of the points in chapter 3.3.3 mentions , was pointless and had no effect on drilling efficiency. The discussion on hole section performance does however oppose this, and we see repeatedly a significant improvement in batch 2 wells compared to batch 1. With all this in mind, it does not seem very conclusive to suggest that also performance incentives do play a large part when it comes to drilling performance.

## 6. Summary

It is clear that when seeking to identify the root causes of increased performance, we can't dismiss one effect or the other. Batch effect, performance incentives or drilling optimization, the most reasonable is that the result is a combination. The experience gained from the first batch, the improvements and advisory support from the drilling optimization specialist as well as the incentives that made the organization "wake up", all together added up to the improved performance we see here.

This thesis has not achieved its objective to find The Value of drilling Optimization as defined by Chen [4]. However, an estimated "average" value of the total optimization has been found. As mentioned earlier this may not necessarily be a bad approach?

Drilling in terms of drilling for oil is when we drill a hole into the earth subsurface to extract hydrocarbons. If you check the online dictionaries available you will find a diversity of definition for "optimization". To mention a few it may be defined as:

*"To make as perfect or effective as possible"*

*"To take the full advantage of"*

*"To find the best compromise among several often conflicting requirements" [52]*

The last one is taken from the field of engineering design so let's go with that one. If we think about what drilling optimization then actually should mean it should be; "the process of finding the best way of drilling a well when considering the conflicting requirements". The best way is then further defined by the operator company's who buy the services needed for the construction process. Briefly this can be summarized as *"As fast and cheap as possible in a safe way"*. In regards to this approach, can it be that defining drilling optimization as the processes that CHEN describes is a too specific?

When you think about it, the rig crew and the drilling crew are just as important *"to take the full advantage of"*. It doesn't help if you can drill completely trouble free if you spend the saved time on rig logistic problems or extra tripping time.

It doesn't matter if the drilling optimization specialist manages to increase the ROP with 100% if it results in an additional 3 bottoms-up circulation before it's safe to pull out of hole.

And it doesn't matter how fast you drilled the 12 ¼" hole, if the casing collapses due to insufficient well design, then you still need to drill another one.

To optimize the drilling of a well everyone needs to be working together, trust each other, communicate and be consistently focused on performing at their best ability. Thus, the real value of drilling optimization is seemingly not the root cause of a selected service or a few expert personnel. The real value is related to the total approach, the total measures and the will to perform.

According to the coordinators and personnel involved in drilling these wells the key factors weren't their superior services or software. They claim that very high focus on performance, consistency, team effort and constant feedback was the key. It became a team effort between all three parties to deliver the best possible performance and this created motivation and will to perform and improve.

The results from this study confirm that this worked, but it was not until there was a reward in place. The extra will and effort did not come for free. This is maybe the most relevant issue that this study reveals.

The potential is there, but "The juice needs to be worth the squeeze" for all parties involved. When it comes to the drilling service providers they are in a very tough market and in a constant squeeze on price. This makes performance based bonuses very appealing to them. The rig contractor isn't in the same squeeze at the time, but more money on less time spent is good business for any company. When it comes to the operator company, lower cost seems to be their major incentive, but should this be their main focus?

If we take a glance back to the status on the NCS we find the following:

- The production is declining
- ≈ 43% of our future production is to come from additional wells
- The number of wells we are actually drilling is declining

- The time we use from spud to well is online is increasing
- The estimated increase in wells needed drilled per year is  $\approx 17\%$

The inconsistency seems to be unavoidable to take notice of: The additional recovery is to come from new wells, but we are drilling less than we should because rig rates are making them so expensive. The majority of the future production is to come from the big existing fields that were constructed and built with a life expectancy of 25-30 years. These fields have installations that now need large investments and upgrades to keep going. These investments contribute to further increase the installations breakeven point, meaning the minimum production it needs to cover its expenses. If the production is not maintained the investments move the break-even point of the installation up to an earlier date. This will cause the installation to become unprofitable earlier which will cause a loss in the field's tail production. This is loss of future revenue that is accounted for in the market value of the operator companies today. An earlier break-even point also affects the existing undeveloped marginal resources that depend on an installation to already be in place to be profitable. These resources now become unprofitable, hence even more future revenue is lost. This money is already accounted for and considered as "money in the bank" in an economic point of view. Losing these reserves cause degradation of the company's market value followed by a drop in the company's stock price. The most important measure to battle this development is to drill more wells and with today's limited rig availability the only way to do this, is to drill them faster.

So right now, the overall concern for an operator company on the NCS shouldn't be that the wells are getting more expensive, it should be the time squeeze they are in. The primary concern should be to decrease well construction time, because if not the wells required are drilled fast enough the economic loss will be unavoidable.

This is where the total approach to drilling optimization should come in. This approach includes the optimization done by all parties involved, not just the drilling optimization specialist. This approach, as shown by this study, is able to reduce the time consumption.

As the example in chapter 5.5 shows; the time savings earned by using a total improvement approach to optimization, allows the operator / oil company to drill more wells in the same time.

If the operator company is able to create this “total performance is what matters” mentality in the service industry, the cost reduction will follow. Because as such processes become adopted and its acceptance grows, the bar for “target performance” is set higher. In the beginning the service providers collect bonuses for their increased performance, but they are also creating high performance reference wells. With time, these wells make up the fundament that governs the target performance. As the efficiency grows the target performance grows and so is also the case for what is considered “above target performance”. As this development continues the well construction time reduces and more and more drilling will occur in the same amount of time. The reduced day’s on each well contributes to reduce both time and cost. The breakeven point is pushed back into the future and the resources that generate future revenue for the company stays in the bank.

As long as the operator recognize that “The juice needs to be worth the squeeze” and understand the time squeeze they are in they can start a mentality change. Focus on reducing the total time, then the cost reductions will follow.

## 7. Conclusion

The Value of Drilling optimization has been studied by using end-of-well-reports from 8 well's from the North Sea with the same fundamental technical, geotechnical and drilling optimization service base. The wells was drilled in two batches, with batch 1 contracts (well #1-#4) not containing performance incentives and batch 2 contracts (well # 5- #8) containing performance incentives. The incentives affected both the drilling service provider and the rig contractor. The value of Drilling Optimization has been studied, but it was not possible to quantify the effect of drilling optimization as per Chen's definition although a clear total improvement was seen in the second batch. The source of the improvements could not be clearly identified but the study still visualized valuable elements both regarding the development in total drilling efficiency and displays key elements related to the process of optimizing the drilling efficiency:

- The optimization often gets camouflaged by other events affecting the performance targets.
- The absence of an identifiable effect of drilling optimization in the performance targets does not necessarily imply that they have not been present. An apparent negative development in one target may have caused a positive in another.
- The well reports need to have a high(er) level of consistency and detail regarding the performed actions and improvements to reduce the uncertainty and allow identification of the different improvement measures.
- The wells in batch 2 had a higher total drilling efficiency compared to batch 1
- The most reasonable average, when considering drilling time, excluded running and cementing of casing, showed that the time to drill the average well was 2.54 days faster using average batch 2 performances.
- Contract Incentives affects performance - Increased performance does not come for free and needs to be encouraged through contract incentives that impact all parties involved.

- The study further suggests that the real Value of Drilling Optimization is when all parties involved are working together while using their best of knowledge and ability to reach the required targets.
- To assure future production and success on the NCS, operator companies and oil companies need to reduce well construction time, and a Total approach to Drilling Optimization, as the processes and measures described in this thesis, may facilitate the required measures for future success.



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