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Utilization of Planning and Design Data in Drilling Automation and Model Based Process Control on Statfjord

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ABSTRACT

Drilling of oil wells has through time become increasingly difficult due to less accessible oil and depleted reservoirs. Well stability issues and other drilling problems are frequently experienced during drilling of challenging wells, resulting in large costs related to non-productive time. Automated drilling systems are developed to reduce excessive costs from non-productive time through model based process control.

The automated drilling system “Drilltronics” is selected for first use implementation of automated drilling at the Statoil operated Statfjord oil field in the North Sea. Model based process control systems such as Drilltronics uses advanced dynamic wellbore models to monitor the well during the drilling process and to take control of the operation if necessary to prevent incidents. Drilltronics continuously safeguards the well and provides safety triggers by comparing formation parameters to expected modeled values for the drawworks, the top drive and the mud pumps. Some functions of Drilltronics have already been tested in a pilot at Statfjord C with promising results, but some challenges related to data management, data quality and work processes were discovered. Real-time measured data can to some degree be controlled by the use of redundant sets of sensors, but system configuration data may be more challenging to both collect and verify.

This thesis suggests how planning and design data can be utilized as system configuration data in the implementation of Drilltronics on Statfjord. Challenges related to the quality of available planning and design data are also studied, in addition to challenges related to work processes.

The result of the analysis indicates that the quality of current planning and design data may be insufficient as input for model based process control. A suggestion for the utilization of actual data instead of or in addition to planning data is proposed, which will take advantage of offshore data acquisition and verification. Consequently there is a need for establishment of new work processes offshore with the implementation of Drilltronics. Suggestions to new work processes are presented.

SAMMENDRAG

Det har i økende grad blitt vanskeligere å bore lete- og produksjonsbrønner i petroleumsvirksomheten i senere tid. Grunner til dette er at de gjenværende oljereservene ofte befinner seg enten på steder der det er spesielt utfordrende å komme til, eller at en ny brønn krever boring gjennom et reservoar med redusert trykk. Utfordrende brønner kan føre til økt tidsbruk og økte kostnader som følge av uønskede hendelser i brønnen under boring. Automatiserte boresystemer er utviklet for å redusere kostnader ved mer problemfri boring ved hjelp av avanserte brønnmodeller.

Drilltronics er et system innen automatisert boring som skal rulles ut til første gangs bruk på det Statoil-opererte oljefeltet Statfjord i Nordsjøen. Modellbaserte prosesskontrollsystemer til automatisert boring som Drilltronics bruker avanserte dynamiske brønnmodeller for å overvåke brønnen under boreprosessen og ta kontroll over operasjonen dersom det blir nødvendig for å unngå uønskede hendelser. Drilltronics sørger for at drilleren ikke overskrider forhåndsbestemte verdier som kan medføre skade på brønnen ved å kontinuerlig beregne og sette opp grenseverdier på boremaskineriet ved hjelp av brønnmodeller. Systemet vil også kunne reagere hurtig dersom en uønsket hendelse blir oppdaget. Deler av funksjonaliteten til Drilltronics ble testet i den automatiserte borepiloten på Statfjord C i 2009. Utfordringer knyttet til databehandling, datakvalitet og arbeidsprosesser ble oppdaget i denne testen. Mens sanntidsdata i stor grad kan bli innhentet med ulike sensorer er det større utfordringer knyttet til innhenting, oppdatering og kvalitetskontroll av konfigurasjonsdata.

I denne rapporten blir det gitt forslag vedrørende bruk av planleggingsdata som konfigurasjonsdata i implementeringen av Drilltronics på Statfjord. Utfordringer knyttet til datakvaliteten av planleggingsdata er studert, og det er gjort en større undersøkelse av tilgjengeligheten og kvaliteten på denne type data fra noen brønner på Statfjord. I tillegg er det gitt forslag til nye arbeisprosesser for det automatiserte boresystemet.

Resultatet fra analysen indikerer at kvaliteten på dagens planleggingsdata er utilstrekkelig som inngangsdata for modellbasert prosesskontroll. I denne rapporten er det gitt forsag til bruk av faktiske data i stedet for eller i tillegg til planleggingsdata for å øke nøyaktigheten på konfigurasjonsdata som legges inn i systemet. Dette vil foreløbig kreve manuell datainnsamling utført av offshore personell.

PREFACE

This thesis is submitted in partial fulfillment of the requirements of the degree of Master of Science at the Norwegian University of Science and Technology. The work took place in the Statfjord department in Statoil in Stavanger during the spring of 2013. One month was also spent in the Statoil Research Center in Trondheim.

The thesis contains a theoretical part (Chapter 2 and 3) that introduces automated drilling and model based process control, and the relevant wellbore models used by such systems. The second part (Chapter 4 and 5) presents a study performed as part of this project work on the utilization of planning and design data as system configuration data for automated drilling in the Statfjord Drilling & Well department. Based on the results it was possible to suggest new procedures for data management and work processes.

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Stavanger, June 2013,

Runar Eike Toft

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List of Abbreviations

API	American Petroleum Institute
BHA	Bottom Hole Assembly
CBHP	Constant Bottom Hole Pressure
DBR	Daily Drilling Report (Daglig Borerapport)
DOP	Detailed Operation Procedure
ECD	Equivalent Circulating Density
EDM	Engineer's Data Model (Landmark software)
FEM	Finite Element Method
FIT	Formation Integrity Test
GWD	Gyro While Drilling
HWDP	Heavy Weight Drill Pipe
ID	Inner Diameter
ISWC	Intelligent and Safe Well Construction
LOT	Leak Off Test
LPM	Liters per minute (Flow rate)
LWCM	Live Well Configuration Manager
LWD	Logging While Drilling
MD	Measured Depth
MPD	Managed Pressure Drilling
MWD	Measurement While Drilling
NPT	Non-Productive Time
OD	Outer Diameter
PLC	Programmable Logic Controllers
PVT	Pressure Volume Temperature
PWD	Pressure While Drilling
RFID	Radio-Frequency Identification
RPM	Revolutions per minute
RSS	Rotary Steerable System
SPM	Strokes per minute
SPP	Stand Pipe Pressure
TD	Total Depth
TVD	True Vertical Depth
WOB	Weight On Bit
XML	Extensible Markup Language

Chapter 1

INTRODUCTION

1.1 Motivation

As residual hydrocarbon resources are becoming increasingly challenging to reach, the drilling industry has started to make investments in innovative solutions that make drilling possible in previously inaccessible reservoirs. New drilling technologies also tend to contribute to reduced costs by minimizing Non-Productive Time (NPT), because fewer adverse events are encountered. Another favorable factor of new technologies are the improvement of safety for personnel on the drilling rig. Repeatedly the new solutions turn out to contribute to several of the challenges.

The Intelligent and Safe Well Construction (ISWC) Project was commenced in Statoil in 2010 with the mission to increase efficiency and reduce cost through automation and reduction in human exposure offshore ("ISWC," n.d.). The ISWC Project comprises a bundle of carefully selected technologies, including Automated Drilling. Automated Drilling, or more specifically "Model Based Process Control", is a relatively new system that uses a bundle of interconnected dynamic physical models to estimate the current wellbore conditions and suggest limits for the operation of the drilling machinery in order to keep the well within the limits of wellbore stability during the drilling operation. A Model Based Process Control system will also intervene in the drilling operation by automatically taking action if deteriorating wellbore conditions are observed, with a significantly quicker reaction time than a human is capable of.

The Automated Drilling technology selected for the ISWC Project is called Drilltronics and is developed by The International Research Institute of Stavanger (IRIS). Drilltronics continuously safeguards the well and provides safety triggers by comparing formation parameters to expected modeled values for the drawworks, the top drive and the mud pumps (Cayeux et al., 2011). This way the automated system assists the driller in reacting to possible events and making quick decisions.

1.2 Scope of Thesis

The Drilltronics system is dependent on an amount of input parameters to work properly. A constant flow of real-time signals of the current well conditions is used by the system. Although several drilling parameters are measured continuously and will be automatically updated in Drilltronics, much of the required data is still managed manually. Configuration data, consisting of parameters from the design phase, are mostly entered manually and does also require manual updates if the actual drilling parameters start to deviate from the planned parameters during the drilling operation. The consequence of deviating configuration data is a gradual development of an inaccurate wellbore model that will result in safeguards and safety triggers that react on wrong premises. Real-time measured data can to some degree be controlled by the use of redundant sets of sensors, but planning and design data may be more challenging to both update and quality control.

Statfjord C is selected as site for the first use implementation of Drilltronics planned in 2013. A pilot of Drilltronics was performed on Statfjord C already in 2009 with promising results, but several challenges with the system were at the same time discovered.

- Is the required configuration data available prior to the drilling operation?
- Is the quality of available planning and design data adequate?

The introduction of new work processes for automated drilling systems is also an important topic. In many situations today several people do the same job, and the necessary data is stored in a number of different file systems. For the automated drilling system to run flawlessly it is necessary to have work procedures specifically established for this purpose. Some important issues related to roles and responsibilities of system configuration data for an automated drilling system are listed in Cayeux et al. (2010):

- Who shall be responsible for maintaining the different parts of the configuration data?
- How shall the configuration data be maintained?
- When shall the configuration data be updated?

1.2.1 Objectives

This thesis will suggest how planning and design data can be utilized in the implementation of Drilltronics on Statfjord. Challenges related to the data quality of available planning and design data are also studied, in addition to challenges related to work processes.

Planning and design data from three recently drilled wells at Statfjord C have been analyzed and compared with actual drilling data from these wells. Actual data is data that has been reported during the drilling operation, often collected in the Daily Drilling Report (DBR), as opposed to planning data which is made before the drilling operation. This analysis gave indications of the quality and availability of current planning and design data. The result of the analysis made it possible to propose new work processes for the implementation of Drilltronics on Statfjord in the near future.

1.2.2 Contents

Chapter 2 gives an introduction to automated drilling and model based process control. A description of physical wellbore models, which is a primary ingredient of model based process control systems, is also included. The basic theory underlying the dynamic wellbore models that are basis for the automated drilling system Drilltronics are given here.

Chapter 3 presents the functions of the automated drilling system Drilltronics. In order to operate properly the system requires a comprehensive set of system configuration data. Experiences relating to data quality of input data and work processes from the offshore pilot of Drilltronics, which was run on Statfjord C during three months in 2009, are also described briefly.

Chapter 4 presents a study of planning and design data on three wells on Statfjord C. The study was performed as a part of this project. The current data management and work procedures on Statfjord are described briefly.

Chapter 5 discusses the results from the analysis of planning and design data from Chapter 4. Challenges regarding acquisition of configuration data are discussed, in addition to a comparison of the current data quality compared to the required quality. This chapter also suggests new work processes in relation to the implementation of automated drilling and model based process control on Statfjord. Finally a short discussion is given concerning future possibilities for collection of configuration data to an automated drilling system.

Chapter 6 describes the conclusions drawn based on the work in this thesis.

Chapter 2

MODEL BASED PROCESS CONTROL

Industrialization of a drilling rig through mechanization and automation enables drilling of challenging wells with increased efficiency and reduced risks. One of the main motivations for the industrialization of the drilling process is to enhance safety by removing personnel from the rig floor. Industrialization is also beneficial for increased efficiency, reduced possibility of adverse events, and reduction in non-productive time (NPT). Increased efficiency has already been proven after the mechanization of the rig floor (Abrahamsen, 2005). A number of new solutions within drilling automation have been introduced and taken in use in recent years. Some techniques are based on safeguarding, ensuring that some parameters are staying within acceptable limits, while other techniques are based on active control of one or several parameters of the process. In both cases active safety triggers are an integral part of the solution in order to get a correct response in case of abnormal conditions. *Managed Pressure Drilling (MPD)* is a modern drilling automation technology which provides automatic active control of the downhole pressure by topside choking and active backpressure pumps. *Model Based Process Control* systems, sometimes referred to as *Automated Drilling* or *Drill-by-Wire*, implements safeguards and safety triggers that control the drilling machines based on wellbore models in order to stay within acceptable limits for both the formation and the drilling machinery. Model Based Process Control can very well be used in an MPD context to protect the well from excessive acceleration of mud pumps or drill string movements that in several situations cannot be handled completely by the MPD topside chokes and backpressure pumps.

2.1 History of Drilling Industrialization

The oil & gas industry has, similarly to industries in general been industrialized in several areas. The manufacturing industry was among the first industries to implement mechanization, which led to an optimization of productivity, quality and efficiency. Mechanization is the utilization of machinery to assist humans with the physical requirements of work. Mechanization is, along with computerization, defined as a component of and a prerequisite for automation (Thorogood, Aldred, Florence, & Iversen, 2010). One of the first forms of mechanization in the manufacturing industry was the introduction of the assembly line by Henry Ford in 1913. With that invention the efficiency of car manufacturing increased dramatically. Automation is a step beyond mechanization by assisting humans in sensory and mental work. Automated systems use machines, control systems and information technologies to increase productivity and quality beyond what is possible with human labor, and to reduce the mental workload of humans. A well-known automated system is the aircraft automatic pilot which was first demonstrated by Lawrence Sperry in 1914 (Scheck, 2004). The first autopilot let the aircraft fly straight with a constant altitude, and could also manage take-off and landing.

The rig floor has been strongly industrialized through mechanization in the recent decades. The early rigs from the 19th century involved manual operations with dangerous and unguarded equipment. The entire 20th century was a great period of inventions and new-developments on drilling rigs. Mechanization in exploration and production drilling has developed steadily especially since the 1970s to seek improved efficiency and reduced risks (Aldred et al., 2005).

Table 2.1 shows an overview of some of the important improvements from the last century. Mechanized roughnecks and slips were taken in use in the 1970s. In the 1980s local automated systems were developed for repetitive and tough operations like roughneck and pipe-handling. The 1990's was the decade when the modern driller's workstation was developed. The drilling workstation "Cyberbase" (Figure 2.1) was connected to a computer network that for the first time interconnected all drilling machinery and sensors to one unit (Tonnesen, Berg, Stromsnes, Kvalvaag, & Pedersen, 1995). That way, the mud pumps, the iron-roughneck and the top-drive could be remotely controlled from a control room. The invention revolutionized the drilling process, and the information flow went from being isolated and separated to becoming more easily accessible. The mechanization of the rig floor from the 1970's led to a great increase in safety, because less work on the dangerous drill floor had to be done by humans. Human derrickmen and roughnecks were exchanged by human-controlled machines that were able to perform the same jobs consistently and safe.

The development of advanced technology continued in the 00's, and various methods to provide automation to the drilling process itself were introduced. Managed Pressure Drilling (MPD) and Drill-By-Wire systems are the most promoted of automated drilling systems:

- In MPD operations the downhole pressure is automatically controlled by topside choking, to achieve a much more stable bottom hole pressure than in conventional operations (Godhavn, Pavlov, Kaasa, & Rolland, 2011). This goal can be achieved in different ways, and the main categories of MPD technologies are Constant Bottom Hole Pressure (CBHP), Mud Cap Drilling, Dual Gradient Drilling and Return Flow Control (Rohani, 2012).

- Drill-by-wire systems implements safeguards, automatic safety triggers and human-activated automated sequences to the drilling machinery by modeling the downhole conditions in the wellbore. By using advanced wellbore models these systems provide limits to the drawworks, top drive and mud pumps to ensure stability of the wellbore during general machinery operations. In other words, drill by wire systems let wellbore models control the drilling processes, and the systems are therefore also called Model Based Process Control.

Table 2.1 Some important steps of mechanization and automation of the drilling operation. Sources: (Aldred et al., 2005; Eustes III, 2007).

Year	
1930's	Hydraulic feed rotary table
1935	Automated weight-on-bit control
1945	Mechanical slips
1949	The first three arm pipe racking system
1955	The first hydraulic power swivel and the first hydraulic hoist
1970's	MWD and LWD
1975	Mechanical iron rough neck
1981	The first mechanical racking system on a floating rig
1982	The first electronically powered top drive
1993	Remote management of pipe on the pipe deck
1994	The first automated drilling workstation is launched (Cyberbase) (Tonnesen et al., 1995)
Mid 1990's	Rotary steerable systems
1999	The first Active Heave Compensating Drawworks (Nov.com, n.d.)
2004	The first transatlantic remote control of a drilling operation
2004	First use of automated choke control in Managed Pressure Drilling (Reitsma & Couturier, 2012)
2005	Continuous Circulation System was introduced for commercial operations
2006	Commercialization of the first wired drill pipe (Nov.com, n.d.)
2009	Pilot test of the automated drilling system Drilltronics during drilling of several wells on Statfjord C (Larsen et al., 2010)

Figure 2.1 1994 Hitec Cyberbase (Tonnesen et al., 1995).

2.2 The concept

Wellbore models have for several decades been used in well planning software. Steady-state torque and drag, temperature and hydraulic models are popular tools to plan and make predictions of an upcoming drilling operation. The steady-state wellbore models have later been developed further into dynamic models that have been implemented in real-time drilling and decision support systems. Such systems require advanced and fast simulators to model the current state of the wellbore based on all available drilling data. Predicted drilling values, including torque, hook load and stand pipe pressure (SPP), are compared with actual measured values to be able to perform a diagnosis of the current drilling conditions. This way it is possible to detect deteriorating drilling conditions before it becomes a problem.

Attempts have been made since the early 00’s to further develop the real-time drilling support system to a more complex system that can intervene in the drilling operation based on the dynamic wellbore models. The results can be used to control the drilling operation and replace some of the driller’s standard procedures. The process models will also actively interrupt the driller’s actions if potential problems are predicted. The system is frequently described as the driller’s equivalent to the modern airplane autopilot.

The current model based process control systems rely on frequent interaction with the driller. In a long-term perspective such systems may require less human input and take care of a larger part of the drilling process than today. The model based process control system will then be able to rise to a higher level of automation. Figure 2.2 shows ten degrees of drilling process automation, from fully manual to fully automatic, as described in Thorogood et al. (2010). The degree of automation of the functions of the Model Based Process Control system "Drilltronics" are currently considered to be on levels 5 to 7 on this scale:

- Safeguards: Level 6
- Safety triggers: Level 7
- Automatic sequences: Level 5

The various functions will be explained in Section 3.2.

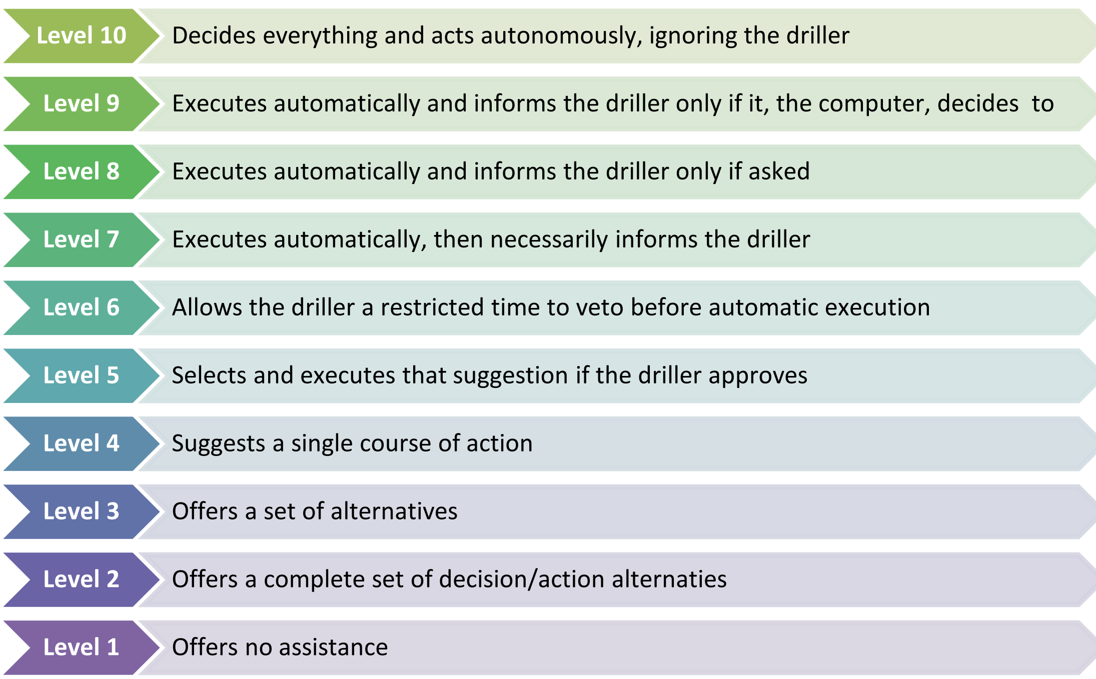


Figure 2.2 Levels of drilling process automation (Thorogood et al., 2010).

This kind of system requires a carefully selected balance of accurate calculations and quick response-time. A very precise wellbore model may consist of multiple interconnected models that require large computer resources. A wellbore model is however not more accurate than the data used as input, and consequently a growing attention to the quality of input parameters have been seen recently. The input parameters consist of real-time data and system configuration data, and will be discussed in more detail in Section 2.5.

The driller has traditionally been given a large responsibility for the drilling operation during oil well drilling. The driller is the only person who can make decisions within seconds and control the drilling machinery. Safe and consistent operations are dependent on the driller's experience and alertness since it is required that the driller reacts quickly and handles well every abnormal situation that can be encountered. Consistent operations also require strict limits for the handling of drilling equipment such as the pumps and drawworks. The limits are based on rig parameters, drilling parameters and formation parameters, where much of the data is uncertain or unavailable. Surface values of hook load, top drive torque and stand pipe pressure are measured and give an indication of the status of the well. Predictions of the downhole parameters WOB (Weight On Bit) and bottom hole pressure require calculations based on the known surface values if measured values from MWD (Measurement While Drilling) and PWD (Pressure While Drilling) are not available. The formation parameters are also uncertain, and are only predicted in advance by extrapolating data from adjacent wells to the new well location. Measurements by MWD and LWD (Logging While Drilling) tools in the BHA (Bottom Hole Assembly) improves the knowledge of the well, but there is often a long delay from the data is captured to the information is interpreted and available to the driller. The driller may as well be too concerned with the handling of the rig instruments to be able to fully utilize the available data. In the meantime an unwanted situation may develop.

Automated drilling involves automatic execution of frequent tasks such as pump start-up, friction testing and reciprocation so the driller's attention can be completely drawn to the important drilling and well parameters. Additionally the automated drilling system provides active limits known as safe guards to hinder overriding predetermined or calculated maximum allowable values for the drilling equipment or the stability of the formation. The system architecture and functionalities of automated drilling systems may vary with different systems, and it was decided to describe Drilltronics in more detail in Chapter 3.

2.3 Physical wellbore models

Process models developed for automated drilling relies on continuous estimations of the mechanical and hydraulic state of the wellbore. The wellbore state is given by a number of physical models, including a hydraulic model, a mechanical model and a thermal model. These models constantly interact with each other to give a complete prediction of the situation in the wellbore. The models are continuously calibrated with measurements. The equations used in different automated drilling systems are in general based on well-established theory. The general physical models are given below, in addition to more specific information toward the models used in Drilltronics. Drilltronics is based on a multiphase transient hydraulics model, a dynamic temperature model and a stiff string torque and drag model (Cayeux, Daireaux, Dvergsnes, & Florence, 2013; Cayeux, Dvergsnes, & Iversen, 2009).

2.3.1 Mechanical model

The equations that are used to calculate torque and drag for the entire drill string are often based on a soft string model. The main assumptions in this model are that the bending stiffness of the pipe is neglected and that the drill string always deforms to the shape of the borehole, which means that the drill string is treated as a heavy cable. The soft string model has proven to work very well in the field and gives a good approximation of the contact forces on the drill string for smooth trajectories, but calculation of complex trajectories and drill string tortuosity requires a different approach. More advanced mechanical models are based on a Finite Element Method (FEM) to calculate torque and drag. Such models require high computer performance and are time consuming and are therefore not suitable for real-time operations (Menand et al., 2006). Menand's model is considerably faster than FEM models, but today is neither of them considered to be fast enough for real-time modeling, which require much quicker calculations speeds than what Menand's model can perform.

The soft string model

In order to calculate the torque and drag on the drill string, the magnitude of the normal force working on the borehole wall for every component of the drill string is required. A higher normal force results in higher torque and drag. Torque and drag is calculated by summing the forces incrementally from the bottom of the string to the surface. The drill string is divided into several parts, which lets the tension force and torque be calculated in a stepwise manner. A simple expression of the magnitude of the normal force, F_n, between the drill string and the borehole wall for one element is determined by (Johancsik, Friesen, & Dawson, 1984):

$$F_n = \sqrt{(F_t\ \Delta\varphi\ sin\theta)^2 + (F_t\ \Delta\varphi + W\ sin\theta)^2} \tag{2.1}$$

where,

F_t	the axial force below the element
$\Delta\varphi$	the incremental change in azimuth along the element
θ	the inclination at the lower end of the element
W	the weight of the drill string element

The incremental axial force of a string element, ΔF_a, is then given by

$$\Delta F_a = W\ cos\theta \pm \mu\ F_n \tag{2.2}$$

and the equation for incremental torsion, ΔM, is

$$\Delta M = \mu F_n r \tag{2.3}$$

where,

μ the coefficient of friction
r the outside radius of the largest part of the string component, which is for the drill pipe normally the tool joint radius.

The sign ± depends on the pipe motion, either upward (+) or downward (-) motion. The friction force always works opposite the pipe movement.

The expression for normal force in eq. (2.1) does only account for gravity. The truth is more complex with several factors affecting the normal force. A more advanced approach that includes drilling fluid viscosity and effects from mud circulation is important to implement in model based process control systems for accurate calculations. The mechanical models used by Drilltronics are tightly connected to hydraulic calculations, making it possible to model the effects of flow rate on hook load and torque, and the variations in torque as function of RPM.

Other soft string models are outlined by several authors: (Sheppard, Wick, & Burgess, 1987), (Maidla & Wojtanowicz, 1987) and (Aadnøy & Andersen, 2001).

The stiff string model

The stiff string model differs from the soft string model by accounting for the actual stiffness and the bending moment of the string. Wells with high tortuous trajectories, high dogleg severity, stiff tubular, or narrow radial clearances benefit from the stiff string model. Stiff string models are in general considered more accurate than the soft string model but require much more complex calculations. A number of different approaches have been used, such as finite element analysis, numerical methods and semi-analytical methods (Belaid, 2005; Mason & Chen, 2007).

The mechanical model in Drilltronics is based on a stiff string model developed by Belaid (2005) (Cayeux et al., 2013), which calculates the deformation state of the drilling assembly in the well with an iterative contact algorithm. An advantage with this model is that it, because of the utilization of a direct integration method of equilibrium equations, is much faster than other stiff string models solved by for instance the finite element method. The Belaid (2005) model consists of four partial differential equations. Equation (2.4) and (2.5) describe the equilibrium of a control element (Newton's law). Equation (2.6) and (2.7) describe the deformation of the control element by Timoshenko's law and are used to derive the actual deformation of the drill string.

$$\frac{\partial \vec{T}}{\partial s} + \vec{f} = \rho A \frac{\partial^2 \vec{u}}{\partial t^2} \tag{2.4}$$

$$\frac{\partial \vec{M}}{\partial s} + \vec{t}\, X\, \vec{T} + \vec{c} = \frac{\partial^2 (\rho I \vec{\omega})}{\partial t^2} \tag{2.5}$$

$$\vec{T} = \overrightarrow{T^0} + EA_s \left(\vec{t}. \frac{d\vec{u}}{ds} \right) \vec{t} + kGA_s [\frac{d\vec{u}}{ds} - \left(\vec{t}. \frac{d\vec{u}}{ds} \right) \vec{t} - \vec{\omega}\, X\, \vec{t} \tag{2.6}$$

$$\vec{M} = \overrightarrow{M^0} + 2GI \left(\vec{t}. \frac{\partial \vec{\omega}}{\partial s} \right) \vec{t} + EI (\frac{\partial \vec{\omega}}{ds} - \left(\vec{t}. \frac{\partial \vec{\omega}}{\partial s} \right) \vec{t} \tag{2.7}$$

where,

$\vec{T}$	the internal effort vector applied to the control element
$\vec{f}$	the linear external force applied to the control element
$\vec{u}$	the displacement
$\vec{M}$	the internal torque applied to the control element
$\vec{t}$	the tangential vector of the Frenet-Serret coordinate system associated to the control element
X	denotes the vector cross product
$\vec{c}$	the external torque applied to the control element
I	the second moment of area
$\vec{\omega}$	the rotation of a section of the control element
k	the reduction factor of the shear force in the Timoshenko theory
E	the Young's modulus
G	the shear modulus
$\overrightarrow{T^0}$	the internal effort at rest
$\overrightarrow{M^0}$	the internal torque at rest

The actual trajectory for the C-9 A well on Statfjord was used by the author in a Wellplan simulation to demonstrate the difference between a soft string and stiff string torque and drag model in a long deviating well. The result is shown in Figure 2.3. The bar on the side shows where along the curve the stiff string calculation differs from the soft string model. Yellow color means equal value, and red and green means negative or positive difference. Most differences are slightly positive or negative, but the values accumulate to a surface torque difference of -620 Nm. This is considered to be a small difference compared to other factors that influence torque. The value will vary with different trajectories and dimensions.

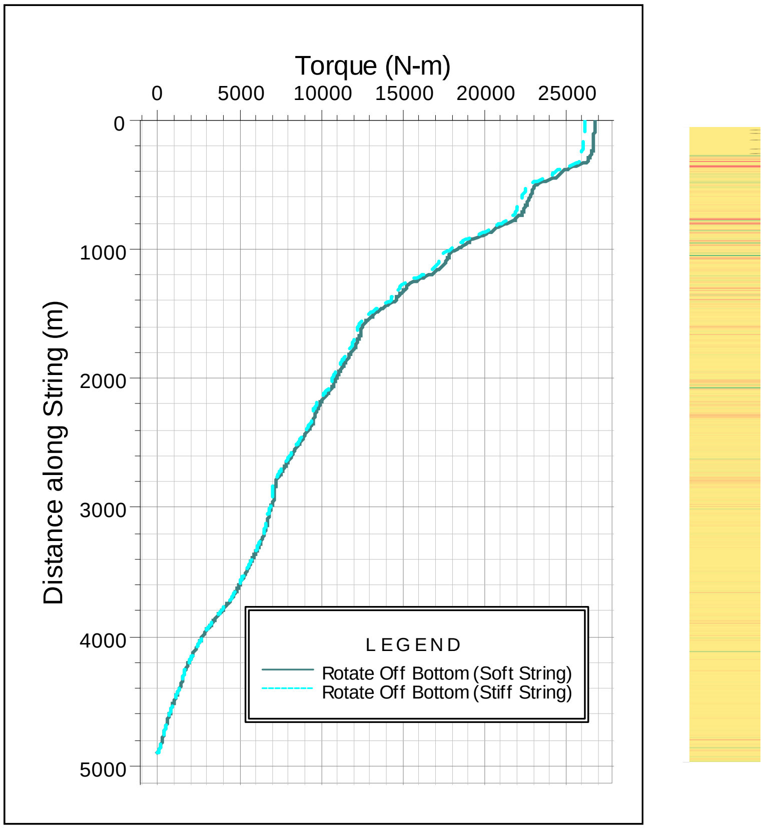


Figure 2.3 Comparison of soft string and stiff string torque calculation for the actual C-9 A trajectory.

2.3.2 Hydraulic model

For process modeling it is important to accurately predict dynamic pressures in the annulus. To get a prediction of the pressure at any position of the annulus it is necessary to have knowledge of the wellbore hydraulics. Even if pressure measurements are available from MWD tools, pressure modeling is necessary either if pressure tools are not working (Herzhaft, Peysson, Isambourg, Delepoulle, & Toure, 2001), if the data bandwidth is limited, and maybe most importantly to get pressure predictions for depths without a sensor. Downhole pressure measurements can be used to calibrate hydraulic models.

Drilling fluids are shear thinning and thixotropic, thus they do not show a direct proportionality between shear stress and shear rate. Different rheological models have been developed to represent the relationship between shear stress and shear rate correctly in order to perform wellbore hydraulic calculations. The three most used Non-Newtonian rheological models for drilling fluids are the Bingham Plastic model, the Power-Law model and the Herschel-Bulkley model, all expressed in Table 2.2. The Bingham Plastic and Power-Law models are popular because of their simplicity, but these models are usually inaccurate to the rheological behavior of drilling fluids. The Herschel-

Bulkley model is the most complex of these three models, and will in most situations give the best description of the drilling fluid rheology. A disadvantage with the Herschel-Bulkley model is that it is difficult to solve, and are normally solved numerically. The need for an accurate and analytical model provided the development of the Robertson Stiff model (Robertson & Stiff, 1976). An evaluation of several rheological models showed that the Robertson Stiff model was in general consistently more accurate than the Herschel-Bulkley model (Gucuyener, 1983). Drilltronics uses a combination of the Herschel-Bulkley model for turbulent flow and the Robertson Stiff model for laminar flow.

Table 2.2 Rheological models.

Newtonian	$\tau = \mu\dot{\gamma}$	(2.8)
Bingham Plastic	$\tau = \tau_y + \mu\dot{\gamma}$	(2.9)
Power-Law	$\tau = K\dot{\gamma}^n$	(2.10)
Herschel-Bulkley	$\tau = \tau_y + K\dot{\gamma}^n$	(2.11)
Robertson Stiff	$\tau = A(\dot{\gamma} + C)^B$	(2.12)

where,

τ shear stress
τ_y yield shear stress
$\dot{\gamma}$ shear rate
μ viscosity
K flow consistency index
n flow behavior index
A, B, C Robertson Stiff coefficients

For conventional drilling, the Equivalent Circulating Density (ECD) at depth i is calculated with the following equation:

$$ECD_i = \frac{\int_0^i \rho\left(D_{TVD,i}\right) g dD_{TVD,i} + \int_0^i \frac{dP}{dZ}_i dZ_i}{g D_{TVD,i}} \tag{2.13}$$

where,

ρ density
g the gravity constant
$D_{TVD,i}$ depth in TVD for element i
$\frac{dP}{dZ_i}$ the pressure loss across element i
dZ_i length of element i

The pressure loss, $\frac{dP}{dZ}$, is the part of the equation which is most complicated. There are several ways to calculate pressure loss, and the calculation depends on the chosen pressure loss model. Density is also seen to vary with depth due to compression and thermal expansion effects, and due to presence of gas and cuttings in suspension.

Hydraulic flow problems can be solved by five equations: The mass balance equation (eq. (2.14)), the constitutive material equation (fluid behavior) (eq. (2.8) - (2.12)), the continuity equation (eq. (2.15)), the momentum equation (Navier-Stoke equation) (eq. (2.16)), and the law of conservation of energy (eq. (2.17)). The fundamental equations are written (Cayeux et al., 2013):

Mass balance:
$$\frac{\partial}{\partial t}(A_c\rho) + \frac{\partial}{\partial s}(A_c\rho v) = q \tag{2.14}$$

Continuity equation:
$$\frac{\partial v}{\partial s} = 0 \tag{2.15}$$

Momentum balance:
$$\frac{\partial}{\partial t}(A_c\rho v) + \frac{\partial}{\partial s}(A_c\rho v^2) + A_c\frac{\partial}{\partial s}p = -A_c(K_f - \rho g\cos(\theta)) \tag{2.16}$$

Energy balance:
$$\frac{\partial}{\partial t}(\rho H) - \nabla\left(Q_f + Q_c\right) - q_s = 0 \tag{2.17}$$

where,

A_c the cross sectional area of the fluid element
v the average velocity
q flow entering or leaving the fluid element during its length
p the pressure
K_f the friction pressure-loss term
θ the average inclination of the fluid element
H the enthalpy
Q_f the forced convective term
Q_c the conductive and natural-convective term
q_s heat generated by hydraulic and mechanical friction

The flow rate through a small pipe segment can be given by the following equation:

$$dQ = v(r)2\pi r dr \tag{2.18}$$

where $v(r)$ is the axial velocity profile.

By assuming an incompressible, Newtonian fluid in a horizontal pipe, the equations can be simplified, and by substituting the continuity equation with a simplified momentum balance equation, the following equation can be achieved (Skalle, 2011):

$$\frac{dp}{dx} = -\frac{1}{r}\frac{\partial}{\partial r}(r\mu\frac{\partial v}{\partial r}) \tag{2.19}$$

Integrating (2.19), entering boundaries and combining the resulting equation with (2.8) yields the following universal relationship between shear stress distribution in the pipe and pressure gradient:

$$\tau = \frac{r}{2}\frac{dp}{dx} \tag{2.20}$$

By combining (2.8), (2.18) and (2.20), we end up with the pressure gradient for Newtonian flow:

$$\frac{dp}{dx} = \frac{32\mu\bar{v}}{d^2} \tag{2.21}$$

The same approach is used for Bingham and Power-Law fluids. The pressure gradient for Power-Law fluids is calculated by combining (2.18) and (2.20) with the power law equation (2.10), resulting in:

$$\frac{dp}{dx} = \frac{4K}{d}\left(\frac{8\bar{v}}{d}\frac{3n+1}{4n}\right)^n \tag{2.22}$$

The corresponding equation for friction loss for laminar Herschel-Bulkley flow (2.11) requires numerical solution to determine wall shear stress (τ_w). The equation can be expressed as:

$$\frac{8\bar{v}}{d} = \frac{\left(\tau_w - \tau_y\right)^{1+\frac{1}{m}}}{K^{\frac{1}{m}}\tau_w^3}\left(\frac{4m}{3m+1}\right)\left[\tau_w^2 + \frac{2m}{1+2m}\tau_y\tau_w + \frac{2m^2}{(1+m)(1+2m)}\tau_y^2\right] \tag{2.23}$$

The resulting τ_w is entered in (2.20) to give the frictional pressure loss.

Annular pressure loss analysis is critical in determining the annulus ECD. Table 2.3 shows resulting hydraulic friction loss equations for Newtonian, Bingham Plastic and Power Law fluids.

Table 2.3 Hydraulic friction loss equations. Modified from Skalle (2011).

	Newtonian	Bingham Plastic	Power Law	
Laminar pipe	$\frac{dp_p}{dx} = \frac{32\bar{v}\mu}{d^2}$	$\frac{dp_p}{dx} = \frac{32\mu_{pl}\bar{v}}{d^2} + \frac{16\tau_0}{3d}$	$\frac{dp_p}{dx} = \frac{4K}{d}\left(\frac{8\bar{v}}{d}\frac{3n+1}{4n}\right)^n$	
Laminar annulus	$\frac{dp_a}{dx} = \frac{48\bar{v}\mu}{(d_o-d_i)^2}$	$\frac{dp_a}{dx} = \frac{48\mu_{pl}\bar{v}}{(d_o-d_i)^2} + \frac{6\tau_0}{d_o-d_i}$	$\frac{dp_p}{dx} = \frac{4K}{d_o-d_i}\left(\frac{12\bar{v}}{d_o-d_i}\frac{2n+1}{3n}\right)^n$	
Turbule-nt pipe / annulus	$\frac{dp}{dx} = \frac{0.092\rho_m^{0.8}\bar{v}^{1.8}\mu^{0.2}}{d_h^{1.2}}$	$\frac{dp}{dx} = \frac{0.073\rho_m^{0.8}\bar{v}^{1.8}\mu_{pl}^{0.2}}{d_h^{1.2}}$	$\frac{dp}{dx} = aN_{Re}^{-b}\frac{4}{d_h}\frac{1}{2}\rho\bar{v}^2$	$a = \frac{(\log n + 3{,}93)}{50}$ $b = \frac{1.75 - \log n}{7}$

Robertson Stiff laminar flow

To estimate pressure loss for laminar flow, the following Robertson Stiff equations for pipe and concentric annulus with no pipe movement needs to be solved for $\frac{dp}{dx}$ (*IRIS Drilling Models Course*, 2013):

Pipe:
$$\left(\frac{48AC^B}{d\left(\frac{dp}{dx}\right)}\right)^{3+\frac{1}{B}} - (3B+1)\left(\frac{4AC^B}{d\left(\frac{dp}{dx}\right)}\right)^{\frac{1}{B}}\left(1+\frac{6\bar{v}}{dC}\right) + 3B = 0 \tag{2.24}$$

Annulus:
$$\frac{48\bar{v}AC^B}{d^2(1-\alpha)^2\left(\frac{dp}{dx}\right)} = \frac{3B}{2B+1}\left(\frac{d(1-\alpha)\left(\frac{dp}{dx}\right)}{4AC^B}\right)^{\frac{1}{n}-1} - \frac{6AC^B}{d(1-\alpha)\left(\frac{dp}{dx}\right)} + \frac{3}{2(B+1)}\left(\frac{4AC^B}{d(1-\alpha)\left(\frac{dp}{dx}\right)}\right)^3 \tag{2.25}$$

Herschel-Bulkley turbulent flow

The following solution of the Herschel-Bulkley turbulent flow equation is outlined by Founargiotakis, Kelessidis, & Maglione (2008).

Equations for Herschel-Bulkley laminar flow rate, q, and mean velocity, $\bar{v}$, can be written:

$$q = (\frac{dp_f/dL}{K})^m \frac{2w(h/2)^{m+2}(1-\xi)^{m+1}}{(m+1)(m+2)}\ [\xi + (m+1)] \tag{2.26}$$

$$\bar{v} = \left(\frac{dp_f/dL}{K}\right)^m \frac{\left((h/2)^{m+1}\left(1-\xi-(y/(h/2)\right)\right)^{m+1}}{(m+1)(m+2)} \tag{2.27}$$

where,

$$m = \frac{1}{n} \tag{2.28}$$

$$\xi = \frac{\tau_y}{\tau_w} \tag{2.29}$$

Empirical equations are necessary to solve turbulent Herschel-Bulkley flows. Local power law parameters are developed as proposed by Metzner & Reed (1955). The local power law parameters, n' and K', are defined by:

$$n' = \frac{d\ln(\tau_w)}{d\ln(\dot{\gamma}_{Nw})} \tag{2.30}$$

$$\tau_w = K'(\dot{\gamma}_{Nw})^{n'} \tag{2.31}$$

The generalized power law parameters are derived by combining eq. (2.26) with eq. (2.30):

$$n' = \frac{n(1-\xi)(n\xi + n + 1)}{1 + n + 2n\xi + 2n^2\xi^2} \tag{2.32}$$

$$K' = \frac{\tau_y + K\left(\frac{2n'+1}{3n'}\dot{\gamma}_{Nw}\right)^n}{(\dot{\gamma}_{Nw})^{n'}} \tag{2.33}$$

These equations are functions of the Herschel-Bulkley rheological parameters and the wall shear stress.

The friction factor, f, is estimated with the following Reynolds number:

$$Re_{MRa} = \frac{\rho V(d_2 - d_1)}{\mu_e} \tag{2.34}$$

where turbulent flow is achieved for

$$Re > 4150 - 1150(n') \tag{2.35}$$

The friction factor is given by

$$\frac{1}{\sqrt{f}} = \frac{4}{(n')^{0.75}}\log\left[Re_{MRa}f^{1-\frac{n'}{2}}\right] - 0.395/(n')^{1.2} \tag{2.36}$$

and finally the pressure drop is calculated with:

$$\frac{dp_f}{dx} = \frac{2f\rho\bar{v}^2}{d_2 - d_1} \tag{2.37}$$

Pressure, temperature and cuttings dependence on wellbore hydraulics

The drilling fluid experiences wide pressure and temperature ranges while being pumped through the well, and the fluid must maintain stable properties under the varied conditions. The mud rheological properties however is often strongly dependent on temperature and pressure variations, and on cuttings particles in suspension (Cayeux et al., 2013; Herzhaft et al., 2001).

Figure 2.4 shows that the effective viscosity of oil based muds decreases with increasing temperature.

The effective viscosity is defined as

$$\mu_{eff} = \frac{\tau}{\dot{\gamma}} \tag{2.38}$$

where,

μ_{eff}	the effective viscosity
τ	the shear stress
$\dot{\gamma}$	the shear rate

Figure 2.5 shows that also the influence of pressure on rheology is high. The shear stress, and therefore also the apparent viscosity increases with increasing pressure.

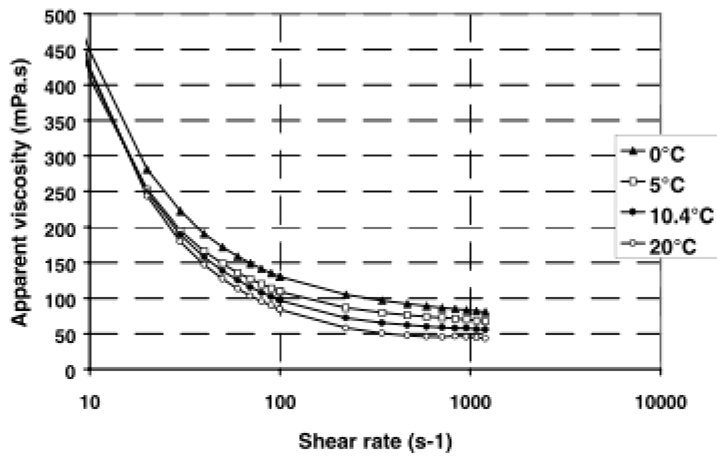


Figure 2.4 Drilling mud apparent viscosity at different temperatures (Herzhaft et al., 2001).

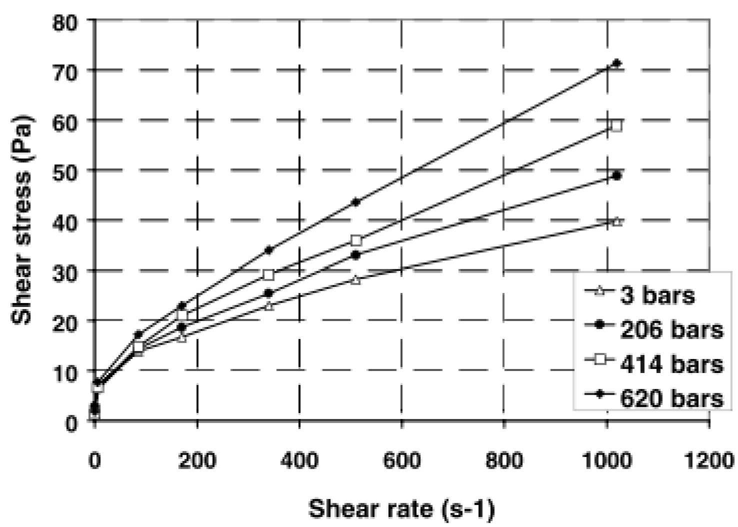


Figure 2.5 Shear rate vs shear stress at different pressures at constant temperature (Herzhaft et al., 2001).

Solids in suspension in the fluid do also have a great influence on fluid rheology, as shown in Figure 2.6.

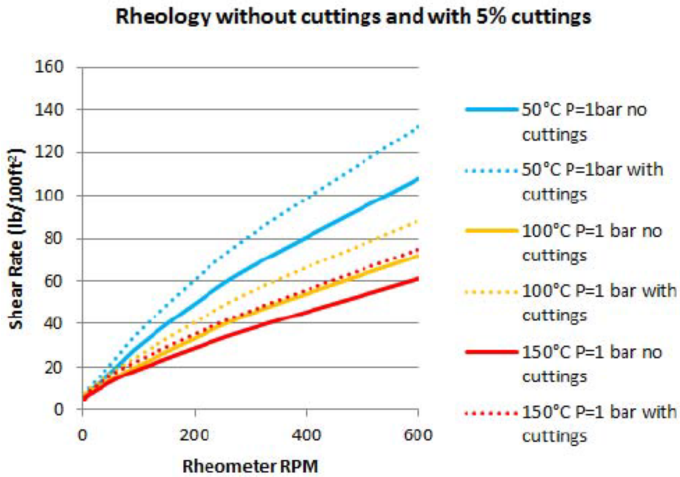


Figure 2.6 Effect of cuttings in suspension and temperature on drilling fluid rheology (Cayeux et al., 2013).

2.3.3 Temperature model

The temperature along the wellbore influences a number of different factors, including the density, the formation stability, the properties of the cement slurry, the functionality of downhole equipment and as seen above the rheology of the drilling fluid. Prediction of wellbore temperature has traditionally been relying on one of three main methods; API correlation, local experience and numerical simulators (Dowell & Ecole, 1998). The API correlation is developed for onshore wells and is not applicable to deep-water drilling. Local correlations may work when an approximate prediction of the bottom hole temperature is wanted, but the method is inadequate in real time applications.

In a drilling operation, heat is transferred along the wellbore during circulation by forced heat convection, between the wellbore and the casing or the formation by conduction, and along a static well by natural convection. In the formation heat is transferred by diffusion.

The governing equation for the formation temperature is

$$\rho C_P \frac{dT}{dt} = \lambda \nabla^2 T \tag{2.39}$$

where,

ρ the density
C_P the specific heat
T the temperature
t time
λ the thermal conductivity

The equation for heat transfer for a circulating wellbore fluid is

$$\rho C_P \left(\frac{dT}{dt} + v\nabla T\right) = \lambda \nabla^2 T \tag{2.40}$$

where v is the fluid velocity.

2.4 Real-time calibration

Any error in the modeling of one of the wellbore models has consequences on other computations. Inaccuracies may occur because of

- Human input error
- Modeling inaccuracy
- Sensor errors
- Incorrect configuration parameters

Human error is difficult to deal with, and must be avoided. Other types of errors must be reduced if possible. For a working set of configuration parameters, the automated drilling system Drilltronics uses an automated real-time calibration system (Cayeux et al., 2011). The system can calibrate:

- The weight of drill pipe (Pipes are usually lighter than expected due to wear)
- Effect of circulation on mechanical drag
- Frictional pressure losses inside the drill string

There are two categories of calibration; global calibration and local calibration. Global calibration is a calibration that does not vary with time. Calibration of the inner diameter or roughness of the drill pipe is a global calibration. The drill string parameters are uncertain and are usually slightly different from the values given from the provider. A very small deviance in inner diameter of the drill pipe has a large effect on the weight of the pipe and consequently the hook load. The roughness of the drill pipe affects the hydraulics and thus the stand pipe pressure. Hook load calibration is best done in the vertical section of the wellbore, and the BHA description should be available early to be able to calibrate the weight of the BHA before HWDP (Heavy Weight Drill Pipe) is run in hole. Figure 2.7 shows an example of rotating off bottom hook load measurements compared with modeled hook load at various depths, before and after calibration of linear weight of drill string. The modeled surface pressure is calibrated by comparing measured stand pipe pressure and downhole ECD, and adding a correction factor for frictional pressure loss inside the drill string.

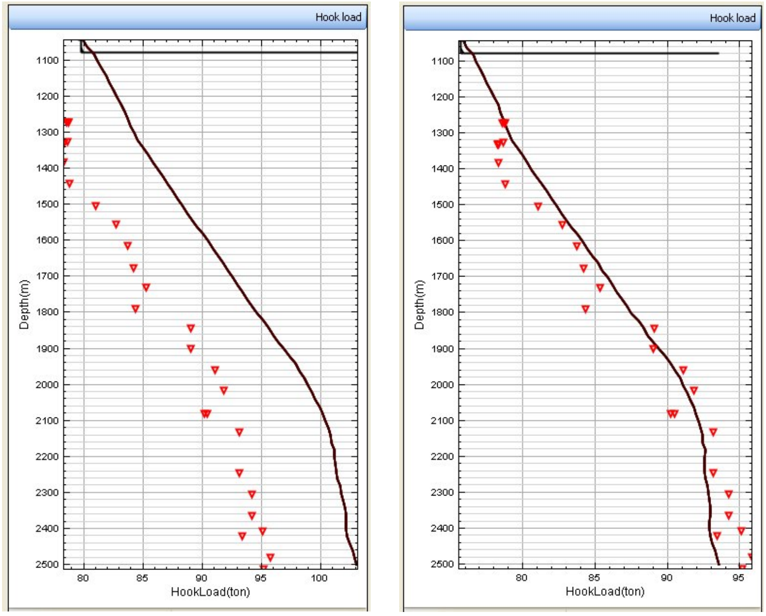


Figure 2.7 Measured vs modeled rotating off bottom hook load before and after calibration of linear weight of drill string (Cayeux & Daireaux, 2008).

Local calibration is a calibration that varies with time. The calibration of the influence of cuttings and temperature on hydraulics varies locally because of variations in these properties along the drill string. Local calibrations are often difficult to get accurate. Tight parts of the open hole or washouts are hard to localize, and the resulting calibration accuracy is not optimized. Better local calibration may be obtained with the use of annular pressure sensors deployed along the drill string (Coley & Edwards, 2013). This will however require wired drill pipe.

2.5 Input data

The model based processes involved in automated drilling systems require updated drilling and well parameters. Every process model requires a detailed set of data dependent on the calculations involved. The data must be correct and available when it is required. This will not always be the case, and the automated system should be designed to account for this. The two main categories of input data are real-time measured data and system configuration data.

2.5.1 Real-time measured data

Real time measurements are provided by available sensors located either downhole or above the well head and are fed directly into the drilling control system. These data are used for updating and calibrating the wellbore models. Some important real time data from the drilling rig are the top drive torque, the stand pipe pressure and the motion of the drill pipe.

Traditionally, the downhole data from MWD equipment is transferred with mud pulse telemetry, and hence, the data transfer capacity is very limited. The mud pulse telemetry is however not the only limitation to the continuous data measurements. The accuracy of the sensors varies from one unit to another, and may also vary based on the operating conditions. The analogue to digital conversion of the mud pulse telemetry may add additional inaccuracies to the downhole sensor data. Finally, a sensor that stops working or provides erroneous values can trick the automated system (Cayeux et al., 2011). It is important to be aware of these challenges when using an automated system.

All the sensors that provide real-time data must be connected to a server from where the automated drilling system can fetch data. Traditionally the drilling data has not been easily accessible. Figure 2.8 shows a typical chart of information flow at the well site. When various drilling data has been acquired the information flow halts. The service companies that provide MWD, LWD and mud logging services have their own ways to manage and process data and consequently the information flow becomes inefficient.

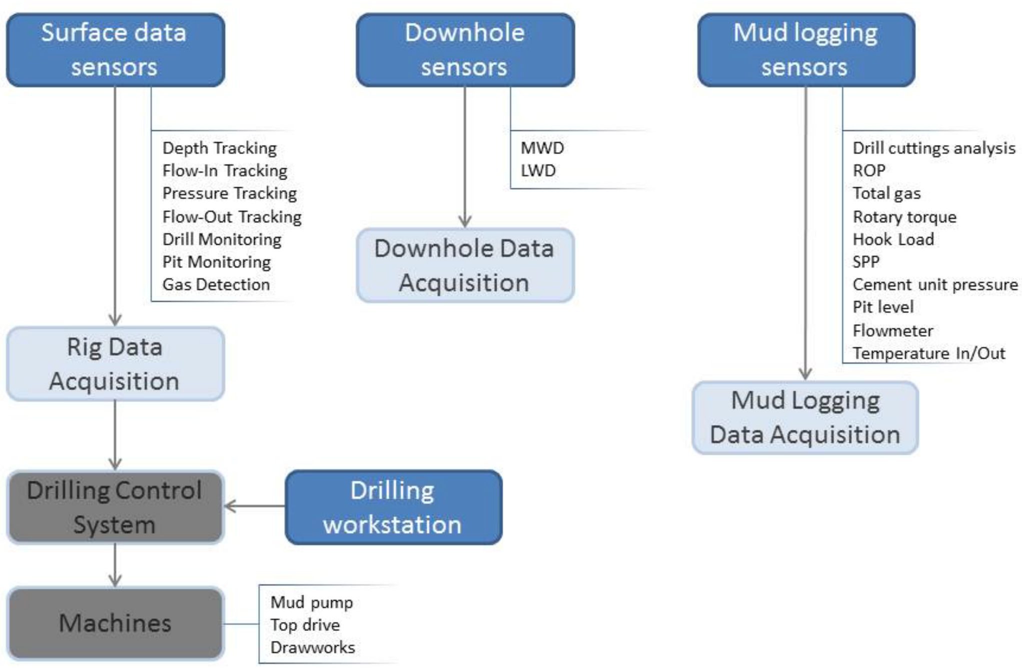


Figure 2.8 Traditional flow of information at the well site.

The automation agents are dependent on continuous communication with real-time data acquisition systems. Therefore the automation agents must be able to handle various types of data traffic, or a central real-time data acquisition and aggregation hub is necessary. Figure 2.9 shows a proposal of a new design for information flow at the well site. This topic has been thoroughly discussed in other papers (Cayeux et al., 2010; *Specification of the Real-Time HUB*, 2011).

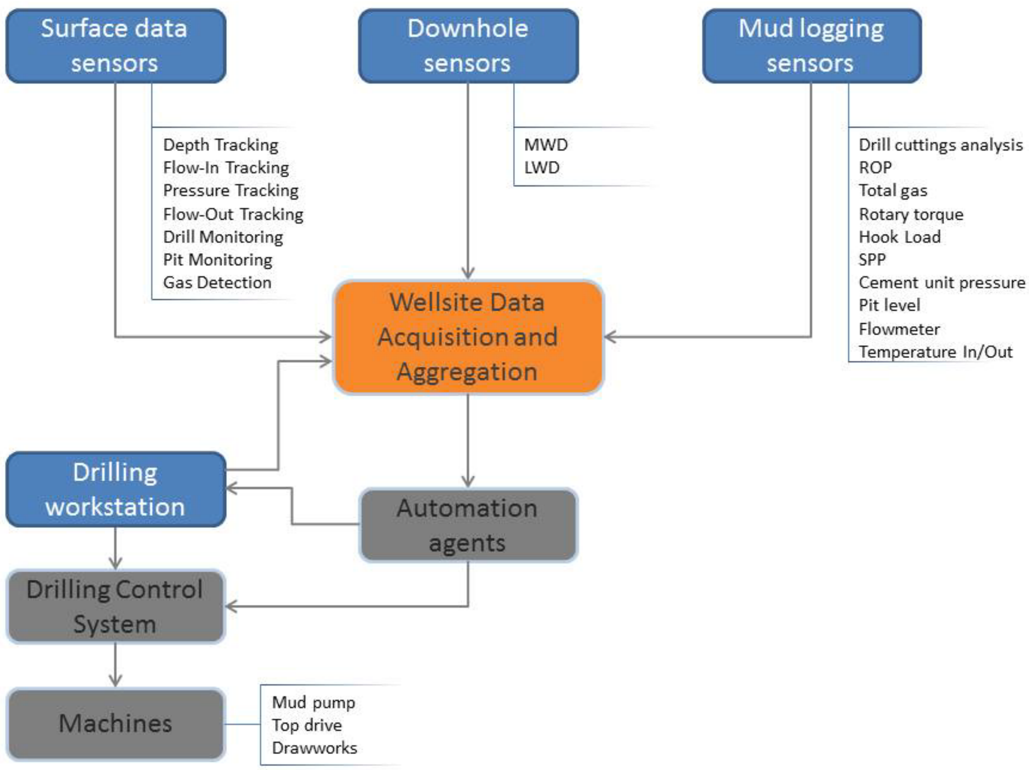


Figure 2.9 New design of information flow for automated drilling.

2.5.2 System configuration data

System configuration data consists of parameters that are configured by various users before and during the drilling operation. These data include the wellbore architecture, the planned well trajectory and properties of the rig equipment such as the drawworks and mud pumps. Formation parameters are also part of the configuration data. Figure 2.10 shows a chart illustrating examples of configuration data needed by automated drilling systems.

When process models are applied in the automation of the drilling process, it is crucial to have an accurate description of the rig, the wellbore, the drilling equipment and the formation. The required parameters can be found in various databases and documents, as explained later in Section 4.1. Information related to drilling operations is today spread over a large number of systems and databases. There is no continuous acquisition of configuration data, and the current configuration of the well must be reported manually. The daily reporting system holds a relatively complete description of the current drilling operation, but there is challenges regarding the reporting frequency and the data systems used for storing the information.

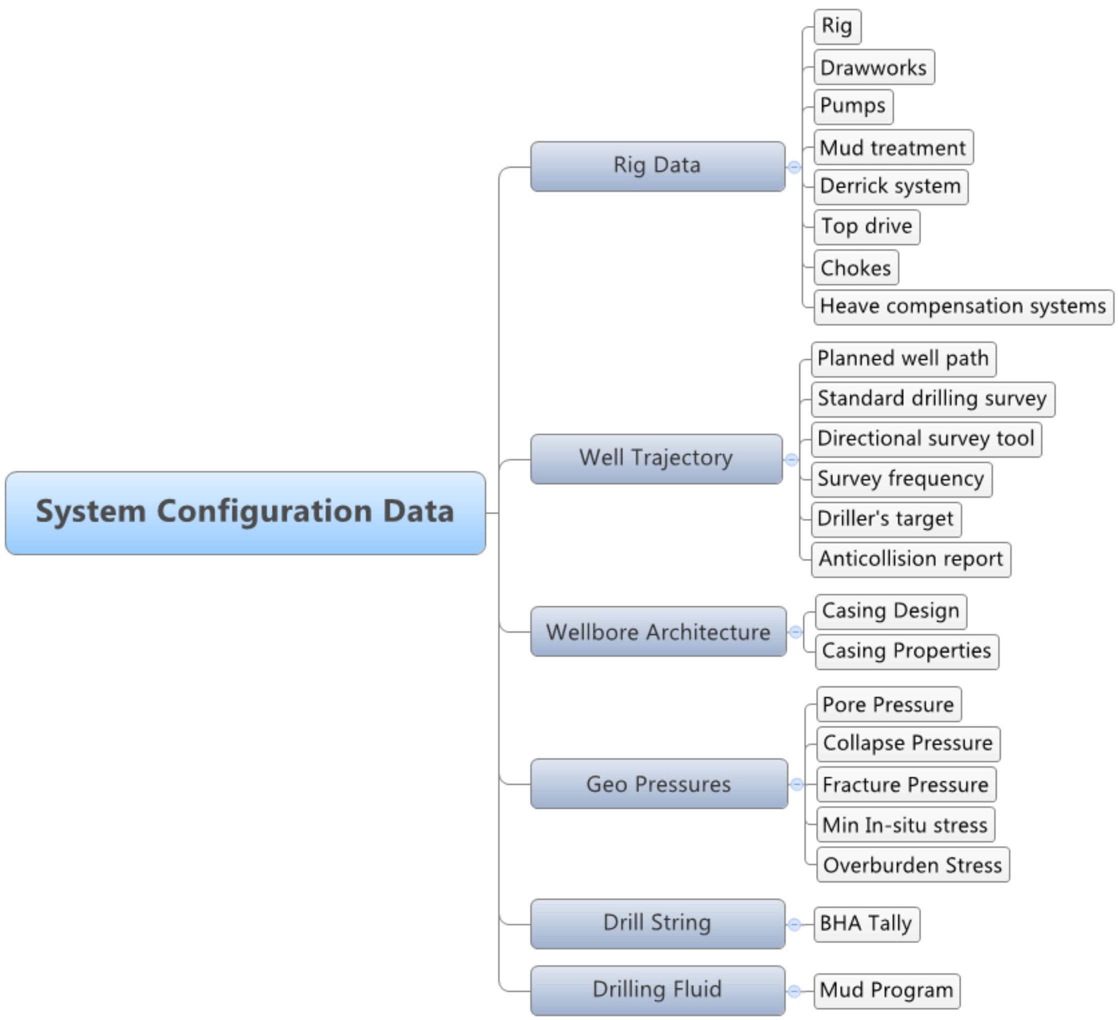


Figure 2.10 List of System Configuration Data required for model based process control.

Rig data

The rig data gives the description of drilling machinery limits. These limits are used as maximum limits for pipe movement and pump operation, if not already limited by formation geo-pressures. The Rig data also contains parameters that are used to calculate the output (mud flow) from the mud pump.

The flow rate is generally calculated by multiplying the stroke volume (V_{stroke}) with the stroke rate (SPM), pump efficiency (η_e), and stroke rate correction factor (η_{SPM}):

$$Q = V_{stroke} * SPM * \eta_e * \eta_{SPM} \tag{2.41}$$

The stroke volume is determined by the size of the mud pump liners in use. The liners may be changed to a different size during the drilling operations, and when this is done the data system needs to be updated with the new information. The same situation applies to the mud pump efficiency, which also depends on the liner size and the operating pressure. An incorrect update or a delay may be a source to critical errors when the automation system is used to actively control the drilling process (Cayeux et al., 2013). Another shortcoming of counting the mud pump strokes is the long time period between strokes at very low flow rates.

There are a few different options to account for errors in the input of configuration data. The system must either have the ability to notice that the input data is wrong, or a manual quality control of the input data is needed. The third option is to measure the flow rate directly instead of calculating it. By applying real-time measurements of either the stand pipe flow rate, or the flow rate before the mud pumps, the flow rate goes from being a property calculated from configuration data to become real time sensor data. The Coriolis flow-meter is one of the few types of flow-meters that are suitable for taking measurements of the mud flow rate, but due to restrictions in maximum pressure that the Coriolis flow meters can handle, they cannot do measurements on the standpipe, but instead measure the flow rate on the inlet of each mud pump (Cayeux et al., 2013).

Well trajectory

The trajectory is in general calculated based on a set of survey stations along the wellbore at regular intervals. Several different tools may be used to take a survey. Today the most popular tools are magnetic multishots and gyro multishots. Magnetic tools have the disadvantage that they give incorrect results in a cased hole and near a cased well because of the presence of magnetic fields. Therefore gyro tools are normally used as the final survey run. Either Magnetic MWD or GWD (Gyro-While-Drilling) is used to take survey stations during drilling.

Geo-pressures

The relevant formation parameters in drilling automation are given in the geo-pressure prognosis. All the gradients are given in equivalent density and are included as an illustration in the drilling program. The data is originally provided by a geologist with the Predict software used as standard in Statoil. The geo-pressure prognosis is the foundation for the casing design and mud weight selection. The casing design is normally planned so that the mud weight is kept above the pore pressure and collapse gradient, and below the minimum in-situ stress gradient in the entire well. Safety margins are often applied in terms of trip margin to overcome swab effect, and kick margin to avoid hydrofracturing and underground blowouts if a kick is taken. A commonly used value for trip and kick margins is 0.06 sg (Bourgoyne, 1986).

Information about depths of formation tops is also necessary because much of the data in the pressure prognosis is associated with specific formations. In Figure 2.11 it is clear that abrupt changes in pore pressure, collapse pressure and fracture pressure gradients can many times be linked to formation tops.

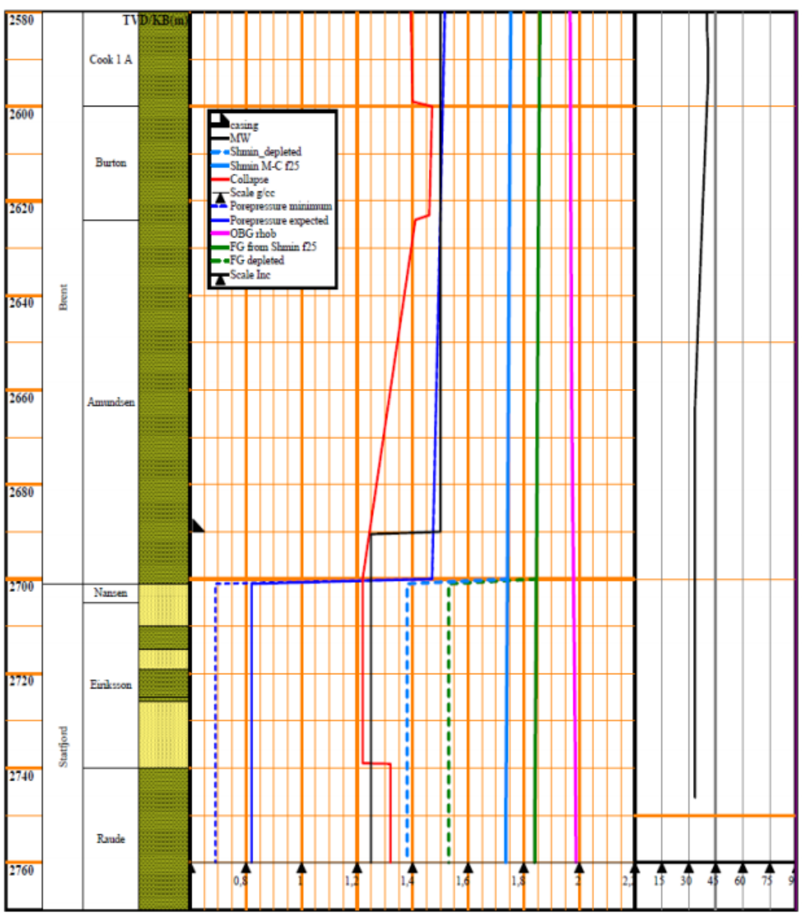


Figure 2.11 Pressure prognosis for a well at Statfjord.

PORE PRESSURE GRADIENT

The pore pressure gradient is generally calculated using the Eaton's method with trend lines accommodating the sonic log:

$$P_{pore} = \sigma_v - (\sigma_v - P_{p,n})(\frac{\Delta t_n}{\Delta t_a})^3 \qquad (2.42)$$

where,

P_{pore}	the pore pressure
σ_v	the vertical stress
$P_{p,n}$	the normal hydrostatic pore pressure
Δt_n	the normal value of sonic Δt
Δt_a	the measured value of sonic Δt

Eaton's equations can also be used with resistivity plots, conductivity plots and corrected d-exponent plots, in addition to the density version which is given in eq. (2.42) (Eaton, 1975).

COLLAPSE GRADIENT

The collapse gradient is calculated by using one of the available failure criterions, which normally requires information about the mechanical properties of the rock and the in-situ stresses. The two most popular failure criterions in wellbore stability analysis are the Mohr-Coulomb criterion and the Drucker-Prager criterion (Ewy, 1999). In Statoil, the Simplified Stassi d'Alia failure criterion is widely used. The Stassi d'Alia criterion is a linear elastic model, written as (Stjern, Horsrud, & Agle, 2000):

$$(\sigma_1 - \sigma_2)^2 + (\sigma_2 - \sigma_3)^2 + (\sigma_3 - \sigma_1)^2 = 2(C_0 - T_0)(\sigma_1 + \sigma_2 + \sigma_3) + 2C_0T_0 \qquad (2.43)$$

where,

σ_1	the maximum in-situ stress
σ_2	the intermediate in-situ stress
σ_3	the minimum in-situ stress
C_0	the Uniaxial Compressive Strength
T_0	the Tensile Strength

The resulting collapse gradient is often adjusted according to experience.

MINIMUM IN-SITU STRESS GRADIENT

The data given in the pore pressure prognosis may be highly uncertain, depending on the knowledge and previous experiences in the area. The minimum in-situ stress gradient is often based on the Breckels & van Eekelen correlations (Breckels & Van Eekelen, 1982):

$$\sigma_h = 0.0053D^{1.145} + 0.46(P_f - P_{fn}) \qquad (D < 3500 \text{ m}) \qquad (2.44)$$

$$\sigma_h = 0.0264D - 31.7 + 0.46(P_f - P_{fn}) \qquad (D > 3500 \text{ m}) \qquad (2.45)$$

where,

σ_h the minimum horizontal stress
D the depth below mean sea level
P_f the pore pressure
P_{fn} the normal pore pressure (water gradient)

The Breckels & van Eekelen correlations are based on hydraulic fracture data from the US Gulf Coast, but were found to give a close match also with fracture data from the North Sea . Figure 2.12 shows leak off test pressures plotted versus depth for the North Sea. The US Gulf Coast curve (Curve 2) is made of the correlations in eq. (2.44) and eq. (2.45). It is seen that the best fit curve for the North Sea (Curve 1) lies up to 21 % to the right of the US Gulf Coast curve.

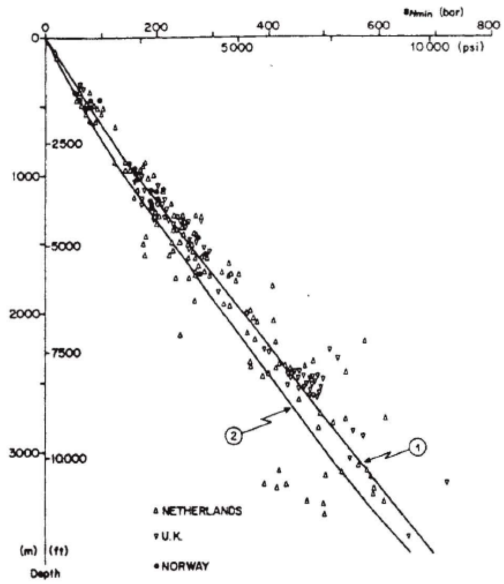


Figure 2.12 Leak off test data from the North Sea. Curve 1 is the best fit curve for the North Sea data. Curve 2 is a plot made of the correlations for the US Gulf Coast. From (Breckels & Van Eekelen, 1982).

Experiences and data from fracturing and LOTs in other wells in the area are also taken into account when estimating the minimum principal stress for a new well.

Another popular way to predict the minimum in-situ stress is by using the Mohr-Coulomb pure friction failure model.

FRACTURE GRADIENT

The fracture gradient is normally added as a multiplier, often 1.06, to the minimum in-situ stress gradient.

OVERBURDEN GRADIENT

The overburden gradient shows the vertical stress plotted versus depth. The vertical stress is the stress which results from the combined weight of the rock matrix and the fluids in the pore space overlying the formation of interest. A popular way in Statoil to calculate the overburden gradient is by using Miller's method based on density logs.

Geo-thermal gradient

The geo-thermal gradient defines the temperature in the formation surrounding the wellbore. The gradient is often given as °C / 100 m. The thermal conductivity and specific heat of the formation rocks are also relevant input data for the thermal calculations.

Drill string

The properties of the drill string are of great importance in hydraulics and torque/drag calculations, which are necessary to make good estimations of downhole properties. All components of the drill string are listed in the BHA proposal section in the drilling program.

The composition of the BHA is often subject to changes during the planning stage, and may change noticeably from the proposal in the drilling program to what is actually run.

Drilling fluid

Some of the main purposes of the drilling fluid are to maintain the wellbore pressure above the pore pressure and the collapse pressure and below the fracture pressure of the formation, and to clean the wellbore from drilled cuttings. The first is mainly dependent on the density of the drilling fluid, while the second is more depending on the drilling fluid's rheology in combination with the drilling parameters pump flow rate and drill string RPM. The salinity of the drilling fluid influences the water transport into or out of the wellbore, in addition to work as inhibitors in reactive clay. Finally the particles in the drilling fluid close the pore throats in permeable formations and reduce the mud loss into the formation.

Every parameter of the drilling fluid is planned in advance and mixed to obtain the desired properties. Detailed recipes of the desired drilling fluids are given in the drilling mud program, which may be found in the drilling program, and limits are given for many of the relevant parameters. During the drilling operation the mud properties are normally measured with approximately six hours intervals, and reported only once a day in the daily report by the company supervisor night. The density, rheology, temperature and solids content are some of the parameters that are measured. The full list of measured and reported fluid properties is shown in Figure 2.13.

5.0 Drilling Fluid Test

	Oil Based			
Sample time	02.09.2012 04:00	02.09.2012 10:00	02.09.2012 17:00	02.09.2012 21:00
Fluid system	Versatec	Versatec	Versatec	Versatec
Sample point	Active pit	Active pit	Active pit	Active pit
Sample depth (mMD)	2 976,0	3 003,0	3 043,0	3 058,0
Mud weight in/out (g/cm3)	1,50 / 1,50	1,50 / 1,50	1,50 / 1,50	1,50 / 1,50
Temp in/out (degC)	32,0 / 26,0	48,0 / 54,0	55,0 / 60,0	57,0 / 62,0
Funnel visc (s/l)				
H2S (ppm)				
Calsium (mg/l)				
Excess Gypsum (kg/m3)				
Excess Lime (kg/m3)	7,77	6,66	4,81	11,47
WPS as chlorides (mg/l)	100 900,00	105 410,00	105 410,00	105 410,00
Organo clay (kg/m3)				
Electrical stability (V)	704,0	773,0	715,0	843,0
Activity of water	0,91	0,91	0,91	0,91
Solids				
Sand (vol%)	0,5	0,6	0,6	0,6
Silicate (kg/m3)				
Water (vol%)	22,0	21,0	20,0	21,0
Oil (vol%)	58,0	59,0	59,0	59,0
Glycol (vol%)				
Lubricant (vol%)				
Solids (vol%)	20,0	20,0	21,0	20,0
Corrected solids (vol%)	19,1	19,2	19,2	19,2
Oil Water ratio	73 : 28	74 : 26	75 : 25	74 : 26
Low gravity solids (kg/m3)	31,00	27,00	27,00	27,00
High gravity solids (kg/m3)	755,00	760,00	760,00	760,00
Viscometer tests				
Plastic visc (mPa.s)	38,0	37,0	36,0	37,0
Yield point (Pa)	10,5	10,5	10,5	12,0
Gel strength 10s/10m (Pa)	6,5 / 8,5	7,0 / 9,0	7,0 / 9,0	7,0 / 8,5
600 / 300 rpm (lbf/100ft2)	97,0 / 59,0	95,0 / 58,0	93,0 / 57,0	98,0 / 61,0
200 / 100 rpm (lbf/100ft2)	45,0 / 30,0	45,0 / 30,0	44,0 / 30,0	46,0 / 30,0
60 / 30 rpm (lbf/100ft2)	24,0 / 18,0	25,0 / 19,0	24,0 / 19,0	25,0 / 19,0
6 / 3 rpm (lbf/100ft2)	14,0 / 10,0	14,0 / 12,0	13,0 / 11,0	14,0 / 11,0
Test temp (degC)	50,0	50,0	50,0	50,0
Filtration tests				
Fluid loss API (ml)				
Cake thickn API (mm)				
Fluid loss HPHT (ml)	2,5	2,2	2,0	2,2

Figure 2.13 Drilling fluid measurements in the daily report from a well in Statfjord.

2.6 Challenges and risks

Automation has in general been associated with computers that occupy roles that has traditionally been performed or controlled by humans. The roles may be part of a high-criticality working environment, where the consequences of failure can be disastrous in terms of safety and costs. Therefore, new solutions must be robust and be able to handle unfavorable situations. The system should provide feedback to the operators in an efficient manner during situations that exceed the capabilities of the automated system.

The system used in process control must be designed to account for many concerns and issues. Thorogood et al. (2010) lists some of these important issues:

- The system must be flexible to allow for additional functionality.
- The system must be able to handle the outcome of potential failure of sensors or communication equipment.
- The available bandwidth for data transmission may be limited.
- Models should provide calculations even when data is limited, but should also offer an indication of the estimated accuracy.
- The heavy equipment used on the drill floor may not be able to change its state as fast as the control system may change set points.

A high degree of knowledge should be held of the reliability of the automation systems. This is also the only way to attain trust to the systems. Trust is important because a decent, well-designed automation system may not be used if it is believed untrustworthy. Calibration of trust is also important because a system may be prone to distrust or overtrust (See Figure 2.14). If trust in a system exceeds the system capabilities, the system may be misused with fatal consequences (Lee & See, 2004).

A reduction in the potential of human error is one of the main objectives in automation. However, automation systems in general are often associated with unforeseen errors (Iversen, Gressgård, Thorogood, Balov, & Hepsø, 2012). A study on the efficiency and reliability of automated monitoring aids suggested that performance is increased and the number of errors is reduced when automation systems work properly. Unreliable systems on the other hand involve higher error rates (Skitka, Mosier, & Burdick, 1999). It is therefore important for the personnel involved to know the limitations and capabilities of automated systems. Although many automated systems can do self-diagnosis, the operator must be aware that the automation system in use may be wrong, and also be able to notice any signals indicating errors to the system.

A study have indicated that the level of process automation in drilling influences the risk of operator handling error (Iversen et al., 2012). A new type of driller is required to avoid the increasing risk of operator error according to the study. The driller must have good understanding of the automated drilling system and of the downhole processes, and be able to focus on the relevant parameters.

A potential error in drilling automation is right after displacement to a different mud or change in mud weight. If the driller relies on the automation system to maintain a given flow rate and the system is not reconfigured with the new mud properties, the result can be formation fracturing or underbalanced drilling.

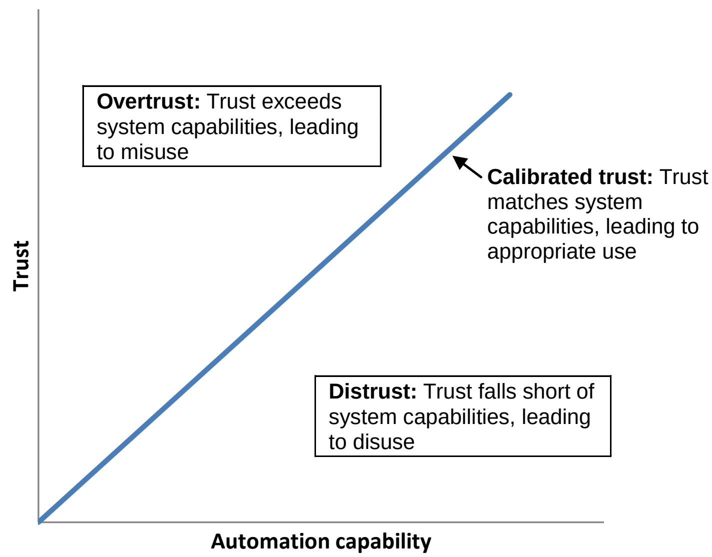


Figure 2.14 Definition of trust in automation systems. Modified from Lee & See (2004).

Chapter 3

DRILLTRONICS

The automation system Drilltronics has been developed by IRIS and NOV since 2001. Drilltronics is an advanced model based process control system that uses a number of wellbore models to predict the current wellbore conditions, and uses this information to actively influence the drilling operation in terms of automatic sequences and safety systems. The system calculates operational limits for drawworks, rig pumps and top drive based on wellbore models in order to provide safeguards, safety triggers and automatic sequences for the drilling operation. The main motivation for using the automated system is to reduce non-productive time by avoiding damage to the well that may be caused by driller actions and by increasing the reaction time when potential problems are detected.

The system relies on a comprehensive set of input parameters to calculate the drilling parameters. There are two main categories of data: Real-time data and configuration data. The real-time sensor data is updated in the process models automatically through real-time sensors and a data acquisition process. Most configuration data requires manual input.

3.1 System architecture

Drilltronics is designed to work with the current NOV Cyberbase workstation. Figure 3.1 shows a topology of the Drilltronics system. The system uses Programmable Logic Controllers (PLC) to control rig machineries and acquire sensor data. The other main part of the system consists of the calculation modules. A machine control server provides communication between the PLCs and the calculation modules, thus it ensures that continuously updated rig and drilling sensor data is sent to the calculation modules, and that updated calculated data is sent back to control the drilling machinery.

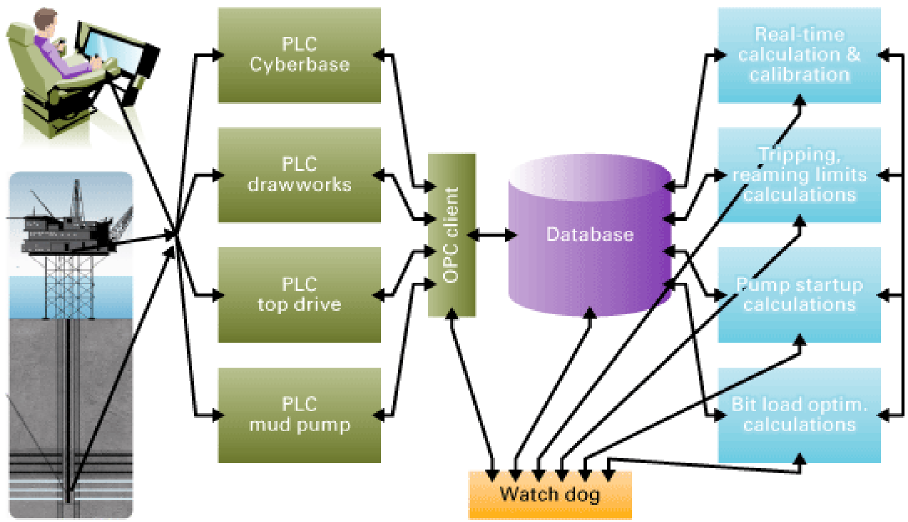


Figure 3.1 Elements of the Drilltronics system (Rach, 2007).

Drilltronics can also be described as a system of layered architecture of several levels as illustrated in Figure 3.2. The outer layer (layer 0) deals with the system configuration and takes configuration data as input and distributes the information to the calculation modules. The mid layers contain the calculation modules (layer 2), and a monitoring manager (layer 1) that supervises the calculation modules. Next is a machine control server (layer 3) that provides communication between the calculation modules and the machine control part. The inner layers contain the machine control hardware (layer 5). A network watch dog (layer 4) checks for communication failure between the calculation side and the machine control side. When a change in the configuration data is made, the outer layer of Drilltronics ensures that the rest of the system is informed of the change. A significant change in configuration parameters, for example because of a new BHA, causes all the calculation processes to restart (Cayeux et al., 2011).

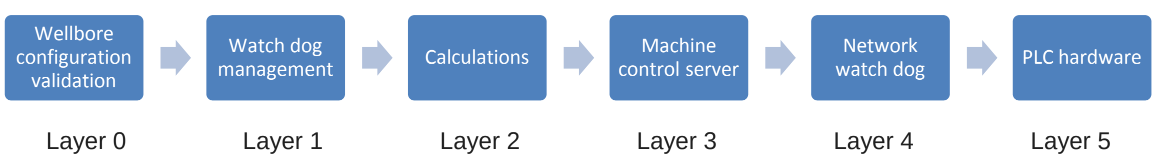


Figure 3.2 The layer architecture of Drilltronics (Cayeux et al., 2011).

The calculation modules make use of advanced mechanical and hydraulic models to compute the limits provided to the automated sequences and safety systems that are used in the drilling operation. The equations used by the Drilltronics models are confidential, but are based on the wellbore models presented in Section 2.3. Because the limits will vary depending on the drilling parameters and operational conditions, an array of calculations are done for each limit to account for various parameters that may be encountered.

The operational stability of Drilltronics has been an important part of the system architecture design. It is worth to note that the machine control side of Drilltronics can work independently from the calculation side for a certain amount of time (several minutes) before its input data is outdated. Therefore those two parts can run asynchronously of each other. In case of a communication error between the two sides detected by the watch dog monitor the current sequence will continue to run until finished, but the system will hinder initiation of new sequences that require the unavailable modules.

3.2 Functions

The various functions of the Drilltronics system are divided into three main categories: Safeguards, safety triggers and automatic sequences.

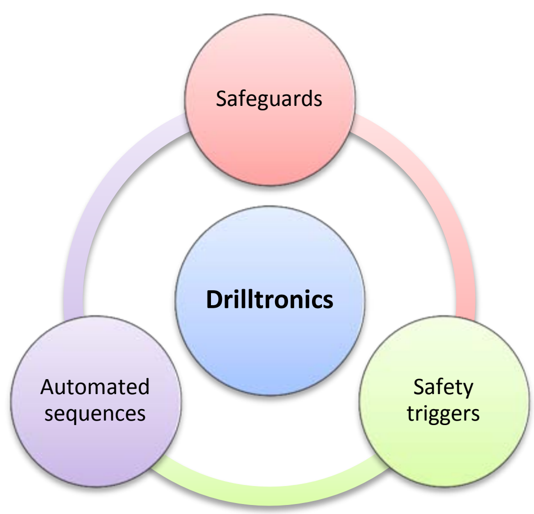


Figure 3.3 Drilltronics main functions.

Safeguards

The safeguards apply to the drawworks and the mud pumps. The safeguards use the dynamic wellbore models to provide limits to the drilling machinery in order to reduce the risk of causing any damage to the formation. The limits are set on frequent driller actions such as axial pipe movement and mud pump management. The axial pipe movement limits are related to maximum up and down velocity and maximum up and down acceleration. Rapid axial movement of the drill string can lead to surge and swab effects which can result in formation failure or fluid influx if the limits of the formation are exceeded. Several pipe movement limits are either directly given to the system or calculated by the system's calculation modules, and the most conservative of the limits is at any time in use. Likewise, Drilltronics will calculate the maximum pump stroke rate that corresponds to the flow rate that keeps the downhole ECD in the open hole section below the fracture gradient, and set it as a limit.

Drilltronics will always select the most conservative of the given limits:

- Drilling machinery limits
- Wellbore stability limits
- Fluid influx limits
- Limits given in the DOP (See Section 4.1.2)
- Limitations set manually by the driller

The driller can in emergency situations easily bypass the limits set by Drilltronics.

Safety triggers

If Drilltronics detects abnormal drilling parameters when compared with the expected modeled values, the system's safety triggers react with either alarms or automatic action. Relevant situations are overpulls, setdown-weights, high torques or pressure peaks due to pack-off. When the response is handled by an automatic system, the abnormal situation is detected quicker and helps preventing additional damage to the well (Cayeux et al., 2011).

Automatic sequences

The last set of functionalities is the automatic sequences. The automation of general sequences such as pump start-up, friction test and reciprocation is beneficial so the driller can fully concentrate on the drilling parameters instead of managing the draw-works and pumps. Another benefit is consistent execution of these general sequences. Drilltronics calculates the expected pick-up and slack-off weight with the use of mechanical wellbore models, so the system can detect slowly changing downhole conditions caused by for instance poor hole cleaning or cavings production.

3.2.1 Interaction with driller

Although the automated systems will provide advanced functions that have direct influence on the automated system the driller is still in charge of the drilling operation. The driller may turn on and off the functionalities of Drilltronics and adjust the limits set by calculation modules. To override the axial hoisting velocity limit in case of emergency, the driller can simply tilt the joystick to the right.

3.2.2 Data validation

Because of the criticality of the quality of the entered configuration data, a validation procedure has been implemented. When any configuration data has been updated the communication between the machine control side and the calculation side is disconnected. The system performs a soft shut down waiting for the current sequences to be completed. Before the functions can be restarted the configuration data must be validated by the person responsible for data validation. The person responsible for the validation should have a very good knowledge of both the Drilltronics system and the various system configuration data.

3.3 Operational limits

The Drilltronics' safeguards and safety triggers ensure that the drilling operation is conducted within safe operating limits. The process model provides limits for ECD, flow rate, hook load, maximum torque and drill pipe acceleration and velocity.

3.3.1 Downhole pressure limits

The downhole pressure limits are defined by the geo-pressures, which were defined in Section 2.5.2. Figure 3.4 shows an example of ECD limits in the open hole section. The lower limit is given by the higher of the pore pressure and the collapse pressure. The upper limit is given by either an FIT bound or the fracturing pressure prognosis.

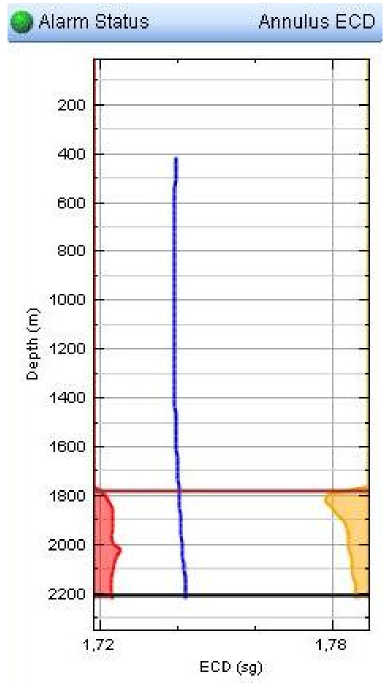


Figure 3.4 Illustration showing the current estimated ECD vs depth (blue line), and the lower and upper ECD limits in red and yellow shadings below the last set casing shoe.

3.3.2 Flow rate limits

The maximum flow rate can be calculated based on the maximum downhole pressure limit. The influence by the drilling fluid on the ECD strongly depends on the density and rheology of the drilling fluid

3.3.3 Hook load limits

There is always a risk of taking weight during axial pipe movement, which will cause a rapid increase in tensile load. During downward pipe movement there is a risk of set-down weight. In both cases a problem prevents an unrestricted pipe motion. The cause may be accumulation of cuttings or cavings, formation collapse, ledges or a key seat. An excessive WOB can also give problems in form of buckling of the drill string or damages to downhole equipment. The upper and lower hook load limits are therefore the tensile yield limit of the weakest element of the drill string, and the sinusoidal buckling limit (Cayeux et al., 2011).

3.3.4 Torque limits

High friction along the wellbore can lead to excessive torque along the drill string. When the torque exceeds the yield strength of the drill pipe, the pipe will twist off.

3.4 Configuration Data Requirements

To enter system configuration data into Drilltronics, the parameters must currently be entered manually into the wellbore configuration editors. The software can be accessible both onshore and offshore, and data should be entered based on the well planning and updated during the drilling operation. There are eight main categories of system configuration editors:

- Rig editor
- Wellbore architecture editor
- Planned trajectory editor
- Current trajectory editor
- Geo-pressure prognosis editor
- Geo-thermal prognosis editor
- Drill-string editor
- Drilling fluid editor

3.4.1 Rig editor

The rig editor takes data from the main drilling machinery on the rig. The mechanical limits on the drawworks and the top drive is required input, in addition to information about rig pumps. The Rig Editor interface for Drilltronics is shown in Figure 3.5. A description of the rig is required to let the process models know the limits of the drawworks, pumps and top drive.

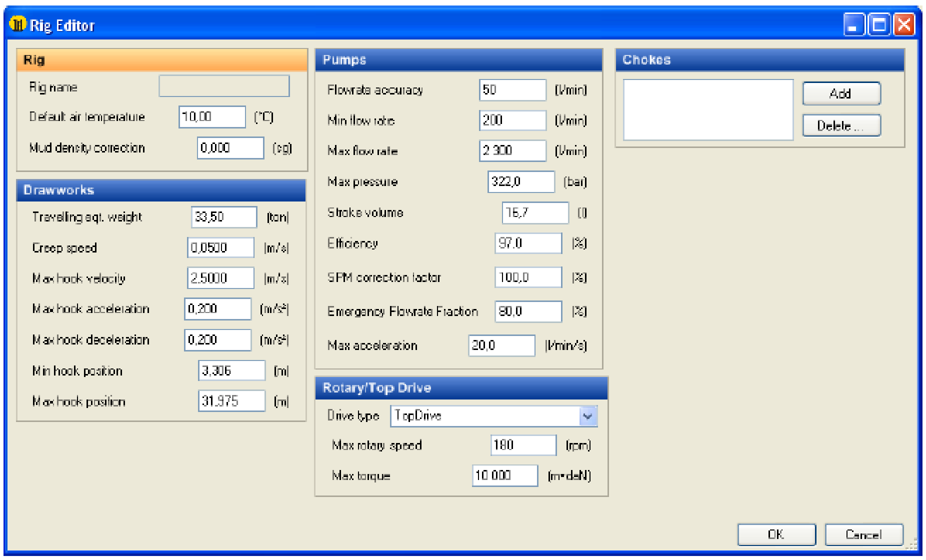


Figure 3.5 The Rig Editor.

3.4.2 Wellbore architecture editor

Detailed information on the wellbore architecture is required by Drilltronics. The wellbore architecture editor, shown in Figure 3.6, is supposed to give detailed overview of the casing program. The shoe depth and dimensions of the casing strings are among the data which is taken as input in the editor (Cayeux et al., 2011).

A function of the casing is to provide zonal isolation to porous or fractured formations surrounding the wellbore. The casing also protects the formation from high pressures causing fractures, or low pressures that may result in fluid influx in the well, cavings production or formation collapse. Finally, the casings function as a part of the well integrity.

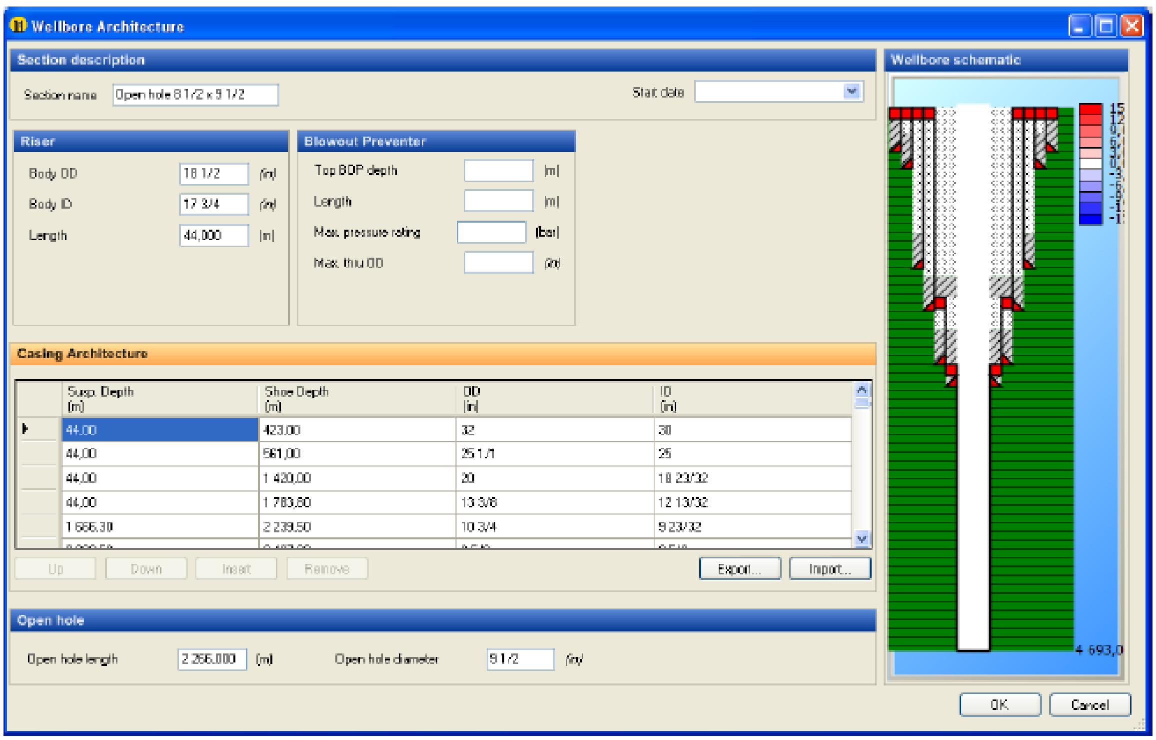


Figure 3.6 The Wellbore Architecture Editor.

3.4.3 Planned and current trajectory editors

The planned and current trajectories can be entered into the configuration editor, shown in Figure 3.7. Both can be imported directly from a tab-delimited text file containing measured depth, inclination and azimuth using the import trajectory dialogue. The current trajectory contains confirmed survey data, normally performed either with wireline or with a drop tool. Directional data is normally available also during drilling with survey shots taken by an MWD tool at regular intervals of 30 meters. If directional survey data is not available during drilling, the planned trajectory is used by the process model.

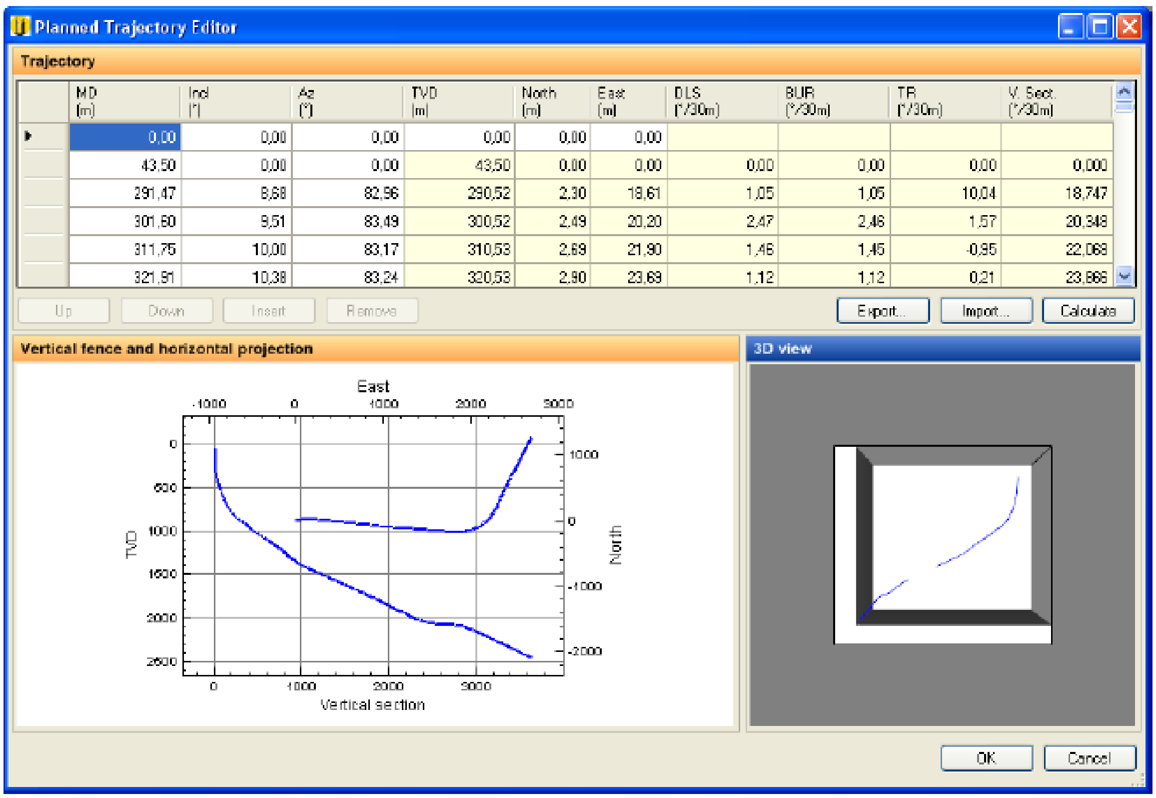


Figure 3.7 The Planned Trajectory Editor.

3.4.4 Geo-pressure editor

A TVD-based geo-pressure prognosis containing pore pressure, collapse pressure, fracture pressure and minimum horizontal stress is required by Drilltronics to define pressure limits. The geo-pressure prognosis can be imported into the configuration data editor from a tab-delimited text file. Results from Formation Integrity Tests (FIT) or Pore Pressure Tests may also be entered in the Geo-pressure editor when such results are available. FIT results will affect the calculated upper limit for a depth of 100 m below the depth of the FIT.

A safety margin and a formation depth uncertainty should also be entered before Drilltronics determines the upper and lower equivalent mud weight limits.

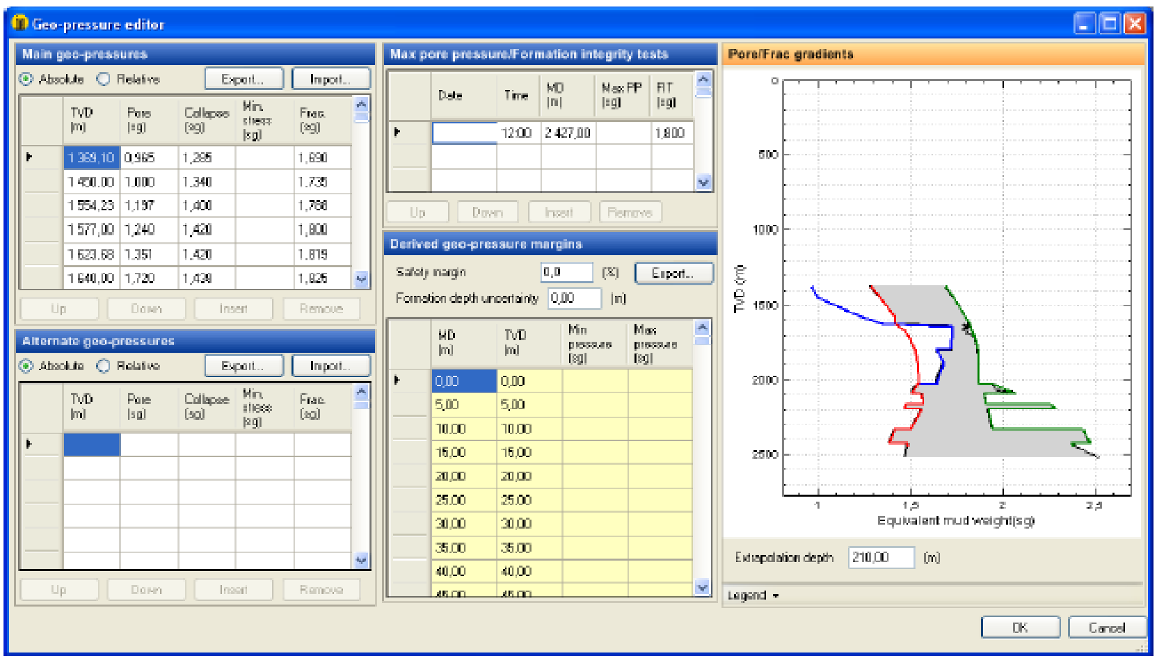


Figure 3.8 The Geo-Pressure Editor.

3.4.5 Geo-thermal property editor

The Geo-thermal property editor takes the proposed geothermal gradient, specific heat capacity, thermal conductivity and density of the medium surrounding the wellbore. The information can be imported from a tab-delimited text file.

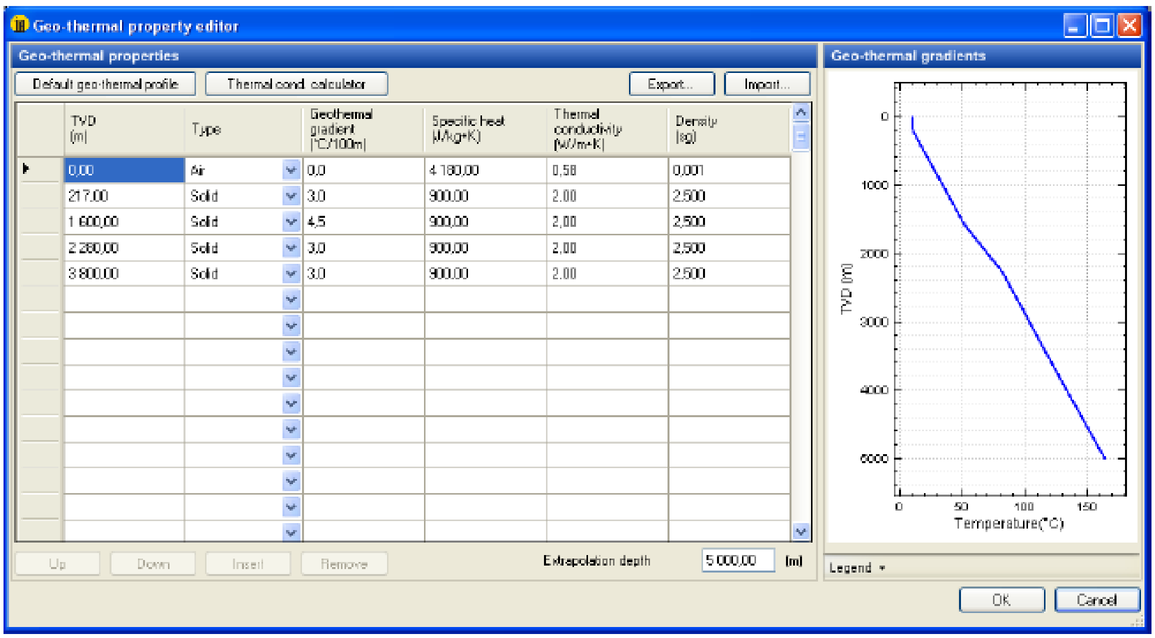


Figure 3.9 The Geo-Thermal Property Editor.

3.4.6 Drill string editor

The drill string editor is used to enter specifications of the drill string. Seven parameters are required for all drill string components:

- Length
- OD
- ID
- Linear weight
- Tensile strength
- Torsional strength
- Make-up torque

The four first listed parameters are given in the drilling program, but the parameters regarding strength may be found in drill pipe specification sheets from the vendor. Some elements of the BHA, typically

MWD and LWD tools and positive displacement motors, require pressure loss coefficients. A pressure loss database of the tools should be obtained from the vendor. For hydraulic calculations it is important to know the total nozzle area of the bit, which is given in the drilling program.

Changes to the shape or flow path of some BHA components may occur during the drilling operation, e.g. opening of an under-reamer or activation of a circulation sub. A ball is generally dropped to apply such a change. The resulting change in ID or OD of the pipe will not automatically be updated in the wellbore configuration data.

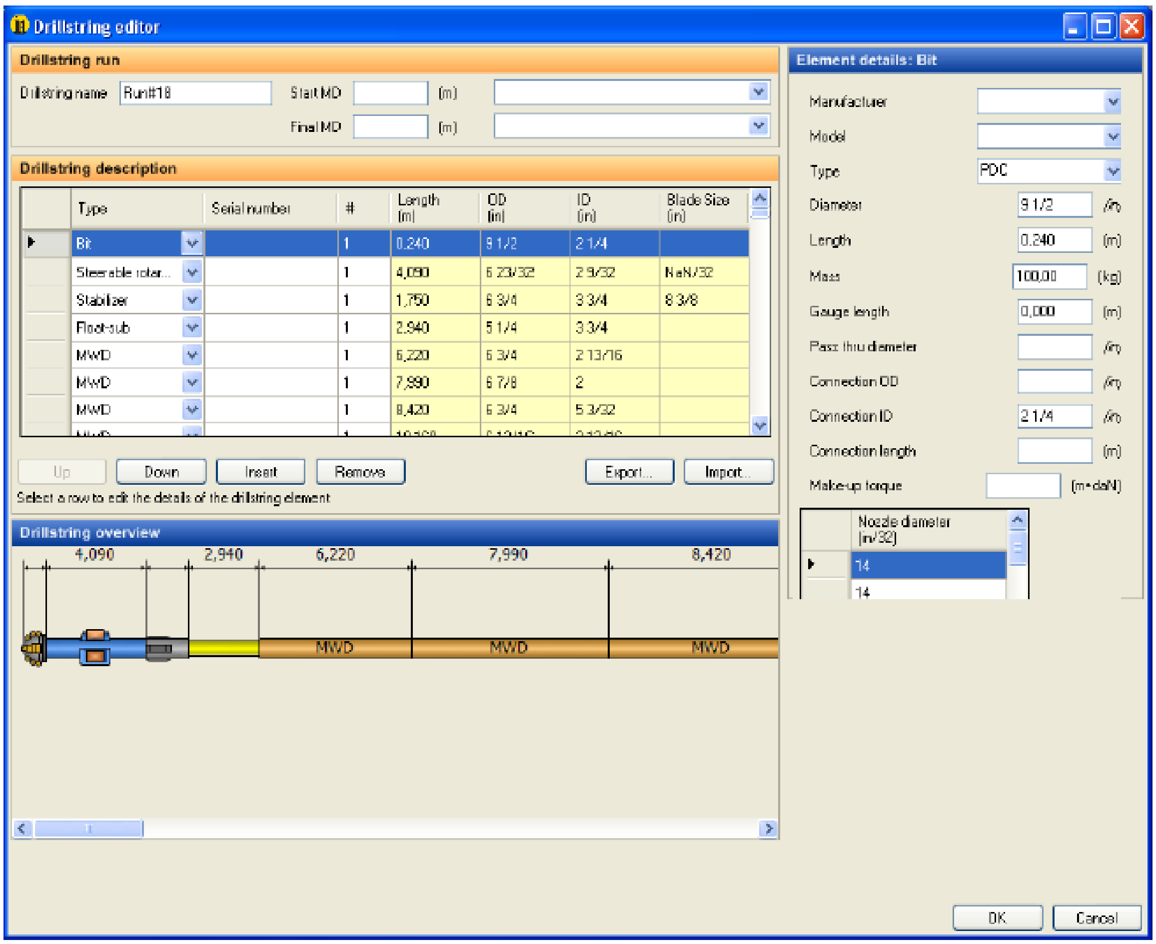


Figure 3.10 The Drill String Editor.

3.4.7 Drilling fluid editor

The fluid editor is used to enter a detailed description of the fluid properties. Because the fluid properties change rapidly the following information must be reviewed and updated often:

- Density of the fluid and its associated temperature
- Rheology of the fluid and associated PVT behavior
- Base densities of the fluid components and associated PVT behavior
- Thermal properties

Technology to measure the density, rheology and temperature of the drilling fluid in real time was tested in the automated drilling pilot in 2009.

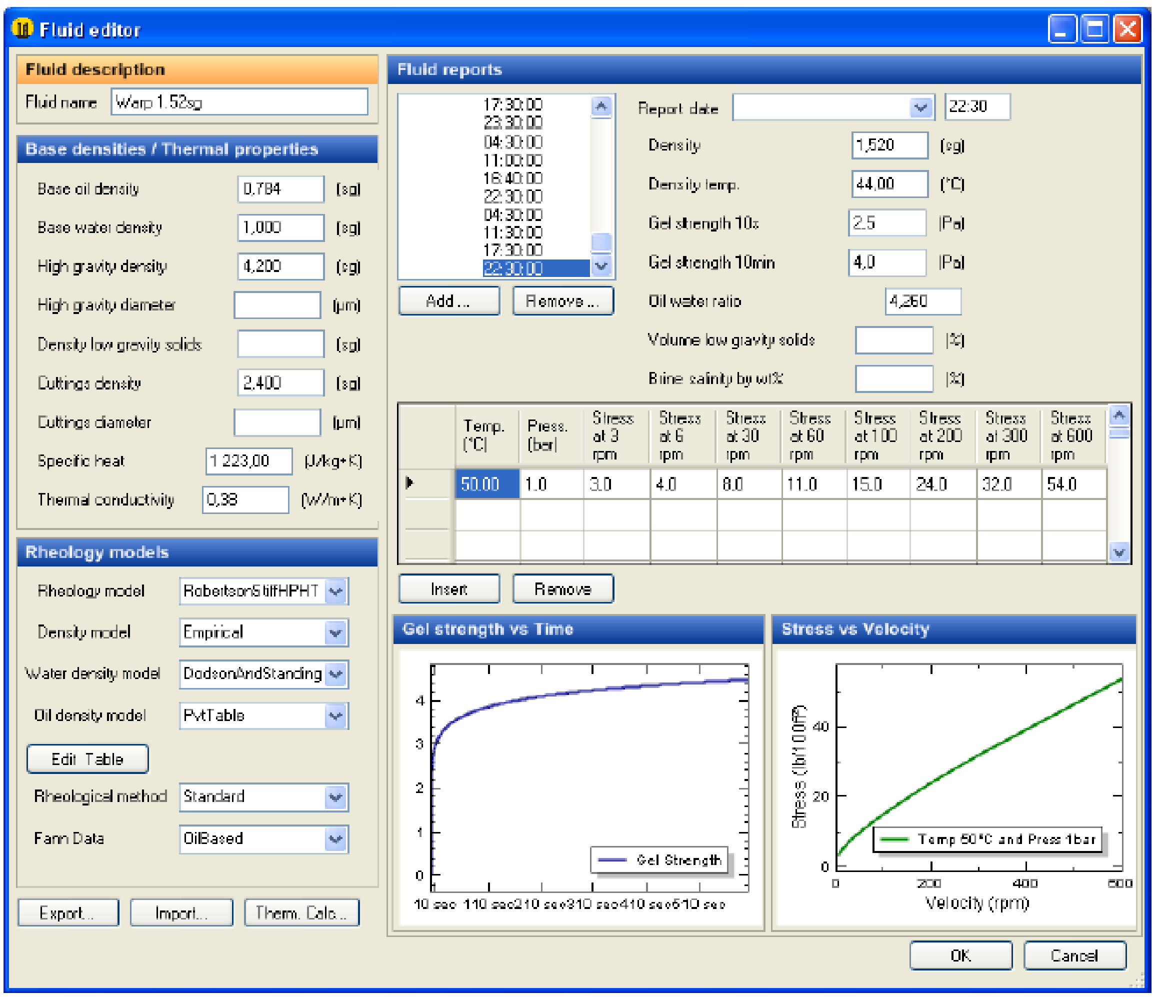


Figure 3.11 The Drilling Fluid Editor.

3.5 Experience from the Automated Drilling Pilot

Drilltronics was tested offshore on Statfjord C from February to May 2009 in an extensive field test. Three of the ISWC technologies were implemented in the test: The automated drilling system "Drilltronics", automatic fluid measurements and drill pipe tracking. Some of the safeguards and automatic sequences of Drilltronics were tested during the drilling of three wells. The automatic pump start-up was used at every connection for the three wells. Automatic friction test and reciprocation were mostly tested in the 8 ½" section of one well (Cayeux, Daireaux, Dvergsnes, & Øye, 2009).

3.5.1 Work processes

The way the configuration data was handled in the Automated Drilling Pilot had several drawbacks. One person was responsible for the Drilltronics system and for obtaining the configuration data from the sources and for entering the data in the Drilltronics configuration editor as seen in Figure 3.12. Errors in configuration data could easily occur due to human error due to the lack of validation procedures. The configuration data were of different data formats and of varying quality from a number of sources. Some of the data (BHA, drilling fluid, and trajectory) were held by different service providers, and some data (BHA details) was even difficult to obtain (Cayeux et al., 2009).

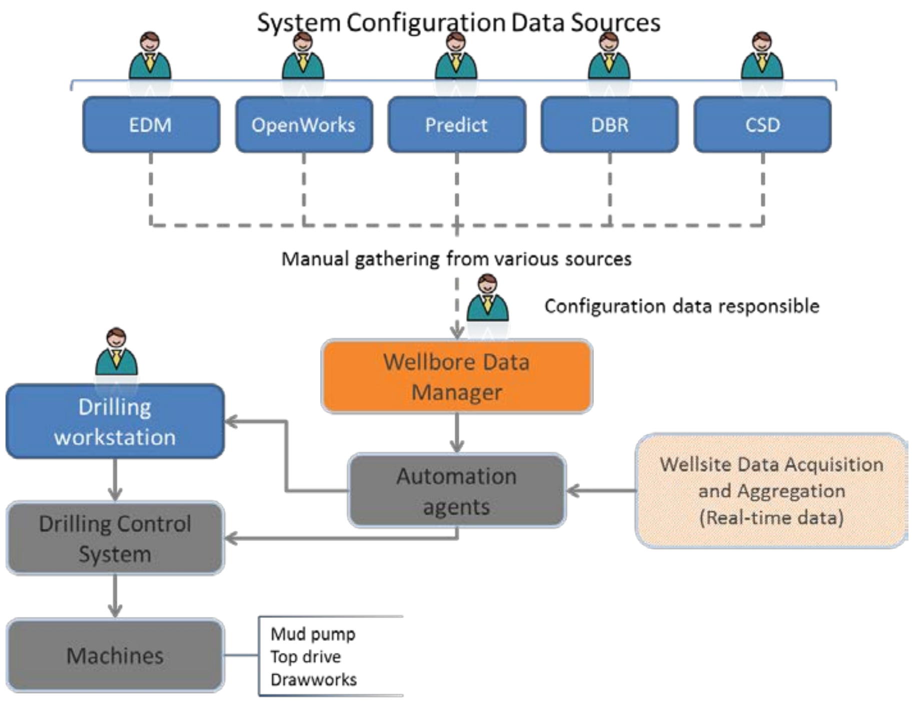


Figure 3.12 An illustration of configuration data acquisition at the Automated Drilling Pilot.

3.5.2 Data management and quality

System configuration data were extracted from a number of different sources, both in electronic formats and in documents. The predicted stand pipe pressures and downhole ECD matched correctly the measured values, indicating quite accurate hydraulic calculations. Several challenges were experienced, and some are presented here (Cayeux et al., 2009):

- A more detailed description of the BHA is required than what was available.
- From the Automated Drilling Pilot on Statfjord C in 2009, a major issue was related to the drill string and BHA description given in DBR, as the inner diameters and linear weights of the drill pipes and HWDP differed slightly from those actually used. This indicated that the As Run drill string tally did not properly describe the actual drill string. The consequence was that thorough calibration of the pipe characteristics had to be done.

3.6 Challenges with configuration data

There are challenges with the use of configuration signals in automated systems. Although they may be seldom changing, some of the configuration parameters have a large influence on the wellbore properties. It is therefore important to have knowledge of the significance of every parameter and define a minimum sampling rate and the required data quality.

Updating the configuration data of the automated system involves a large responsibility. Any person who manually edits configuration data is indirectly affecting the machine control of the drilling rig, because the updated data will go directly into the process models. Consequently the system should have a reliable safety system not only for real time data, but also for configuration data. This is especially important if the automated system is designed in a way that lets it take configuration data directly from sources such as well planning software or the DBR database. Typing errors may give severe consequences.

Chapter 4

EVALUATION OF PLANNING AND DESIGN DATA IN STATFJORD D&W

Work processes and data management varies internally in the different departments in large organizations such as Statoil. Although it is often desired to have similar procedures in the entire organization for increased efficiency, such standards are difficult to implement, especially because of site-specific variations and because of inadequate collaboration between different departments. This chapter highlights the quality and the management of system configuration data in the Statfjord Drilling & Well (D&W) department at various stages in the planning phase and during drilling.

The availability and quality of planning and design data is essential for the decision of whether these data are adequate for use as configuration data in model based process control. Planning data and actual data from three recently drilled wells at Statfjord C have been collected and analyzed to get an indication of the quality of available planning data at Statfjord in order to suggest whether the data can be used as configuration data in automated drilling. Planning and actual data can both be used as configuration data sources. These types of data will be described in the following sections.

4.1 Drilling data management

Information related to a drilling operation is documented several times throughout the planning stage and the operating stage of a well. The procedure for how the data is managed has slight differences throughout the organization, and this discussion is based on the current work processes in Statfjord D&W.

There is currently no data system that contains all the planning data for a drilling operation and the required data must therefore be gathered from a variety of sources. The sources are presented in Section 4.2. Because some of the data originates from service companies with their own file types, and some data originates from simple documents or spreadsheets, it is difficult to gather all the data in one database. Instead, the planning data is collected manually from the sources and pasted into documents called Activity Programs and Detailed Operational Procedures (DOP).

In the early planning stage the planned well data is gathered from various sources into an activity program. The activity program is a document that is regulated by the government. Guidelines for the outline and contents of the activity program are found in NORSOK D-010. The activity program is normally signed and issued at least 10 days prior to commencement of the activity.

Within a day before an operation, a DOP is finalized. The operational details in the DOP are more specific than in the activity program, with updated data. A DOP also often contains suggested maximum limits for flow rate and axial and rotational drill string velocities for parts of the wellbore to avoid drilling problems in problematic areas.

In the very beginning of an operation, data related to some of the configuration data is again updated with actual data. BHA tallies and casing tallies are among the configuration data that may change after the final revision of the DOP is issued. Some changes may occur due to unexpected or undesirable circumstances, while other changes occur because of last minute change of plans.

Actual data from the drilling operation is reported in DBR, which is a tool for reporting daily drilling data. DBR is updated with a detailed description of the activity as run, with most of the available drilling information, including trajectory, mud properties, BHA tallies and casing tallies. Figure 4.1 illustrates on a timeline the documents which will be discussed in more detail below.

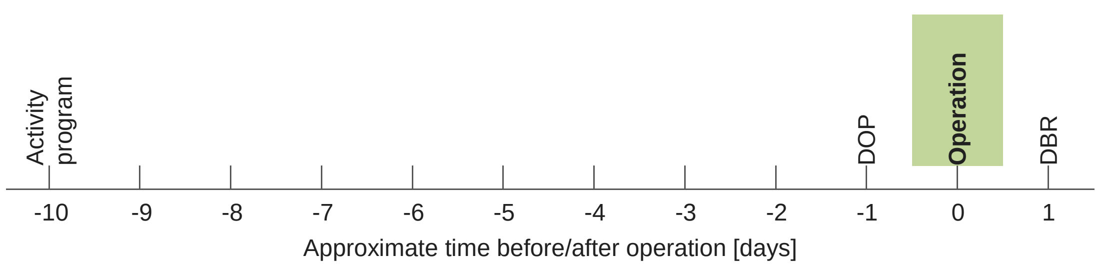


Figure 4.1 Timeline of data management for a general drilling operation.

4.1.1 Activity program

The activity program is a document consisting of a compilation of well design data and expected geology and downhole conditions. This document is the base plan for the drilling operation and gives information and guidelines for the upcoming activity. The program is signed and distributed at least 10 days before the operation, and is therefore limited in terms of updated information close to the operation. The contents of the activity program depend on the activities that are planned to be performed for a well, and may contain P&A, re-entry, drilling, completion, and/or other operations.

The outline of the activity program is generally:

- General information
- HSE and operational risks
- Geology
- Activity (P&A, Drilling, Completion…)
- Organization (Work processes)

Some of the activity specific information given in the drilling program are:

- Well path (Planned trajectory)
- Well design (Casing program)
- Driller’s target
- BHA proposals
- Mud program
- Geo-pressure plot

The information in the activity program is gathered from various sources, where all are related to a common well planning data flow (“Data flow in well construction process,” n.d.). The described data flow is a general guideline published in Statoil, and the work processes varies within the different departments. Personnel from different disciplines prepare information for the activity program, and the data may originate either from well planning software or from simple spreadsheets.

When the geological target for a new well is defined by geology and geophysicist personnel the well planning phase starts. The lines in **bold** are of special interest for Drilltronics and will be discussed in detail.

1. Define initial well path in DecisionSpace, RMS or Petrel
2. Define new well and wellbore in Compass
3. **Detailed trajectory design in Compass**
4. **Pore pressure analysis in Predict/Drillworks**
5. **Design casing program in Stresscheck and Wellcat**
6. Casing wear simulation
7. Torque and drag analysis in Wellplan
8. Design cement program in Excel or Wellplan
9. **Design fluid program in Wellplan**

10. Kick analysis
11. Load analysis in Wellcat
12. Draw completion string in CSD
13. **Prepare geological prognosis in Winlog**

Detailed trajectory design

First, the well trajectory is determined by the drilling engineer in cooperation with a service company representative. The planned well trajectory is entered in the **Compass** application and stored in the EDM database. A principal plan design and an actual design should always be present for each well. When a new plan design (prototype) is made it can be promoted as the principal plan. The previous principal plan then becomes a general (prototype) plan design.

This procedure is also utilized in Statfjord.

Pore pressure analysis

The trajectory from EDM is used to predict temperature and pressure/stress gradients along the wellbore. **Predict** and **Drillworks** is utilized to define the geological prognosis and the formation pressure and strength gradients. The output from Drillworks is imported manually into EDM.

Geo-pressure data exists in EDM only for one (C-9 A) of the three analyzed wells. The geo-pressure plots used in the activity program are outputs from Predict.

Casing program

A casing program is made in the EDM application **Stresscheck** based on defined well sections. The casing program is sometimes called the wellbore architecture or well design. The well design that is entered in the activity program often originates from a spreadsheet document.

Design fluid program

A drilling fluid program is set up by the fluid provider as requested by the planning team. The fluid program contains a list of the fluid components that will give the desired properties. BHA proposals are made by a service provider and are entered in the activity program. **Wellplan** is then used to perform torque & drag analysis, hydraulic analysis and well control analysis based on the available information.

This procedure is also utilized in Statfjord. Planned drilling fluids are stored in separate cases for each section under a well design.

Prepare geological prognosis

The geological prognosis consists of depths and dips of formation tops. This information is either estimated from seismic models or based on previously drilled wells. The resulting geological prognosis is stored in EDM.

The procedure in Statfjord is that the prognosed formation tops are copied and pasted into an Excel spreadsheet. Each version of the geological prognosis is based on a version of the well trajectory from Compass. Geological prognoses are stored in EDM for C-39 A and C-9 A, but not for C-13 A. However, the EDM prognoses and the Excel sheets do not coincide.

4.1.2 Detailed Operation Procedure (DOP)

A detailed operation procedure is a document that contains detailed information on how a specific operation shall be performed. One DOP is often written for separate operations that may or may not be planned already in the Activity Program such as drilling a section, running a casing string, doing a cement job or doing a wireline job. As opposed to the Activity Program, the DOPs are updated and finalized just before the current operation, often within one day before the operation. New DOPs are made for operations that were not planned. The information in the DOPs is based on information from the activity program, but has its full attention on a single operation and describes in detail how it shall be performed.

The DOPs often contain information about maximum suggested parameters during parts of or during the entire operation. Examples are max WOB limits dependent on the rock strength, maximum block speed to reduce surge and swab effects and maximum and minimum flow rate.

The DOPs are normally written by the offshore drilling engineer in cooperation with relevant personnel both onshore and offshore.

4.1.3 Daily Drilling Report (DBR)

DBR is Statoil’s tool for reporting and analysis of daily drilling and well operations data. Drilling data is updated once every day in DBR by the Drilling Supervisor Night, normally around 6 a.m. The data in DBR includes directional data, drilling fluids, bit runs, BHA runs, geology data and casing data.

4.2 System Configuration Data Sources

In Statoil, the system configuration data sources during a drilling operation can be sorted into two categories, planning data and actual data. The largest database for planning data is EDM, and as seen in Table 4.1, EDM can contain most of the planning data. All the planning data is not imported into EDM for all wells, and consequently EDM can currently not be relied on for all data sources. Formation tops and geo-pressure gradients are currently not imported for all wells into EDM. Actual data is reported in DBR.

Table 4.1 Planning data sources in Statoil.

OpenWorks	Driller's Target
Predict	Geo-pressure prognosis
	Temperature gradient prognosis
EDM	Trajectory & well positional data
	Wellbore architecture
	Drilling fluid density and rheology
	Pore pressure / Fracture gradient
	Geo-thermal gradient
	Formation tops
DOP	Max flow rate
	Max block speed
	Max WOB

4.3 Acquisition of configuration data

The planning data that is made available through the activity program is initially spread around in various databases or in simple spreadsheets. The various service providers may also store their data in their own way, and the resulting job of gathering configuration data for an automated drilling system becomes inefficient. By having a single database for all the planning data the processing and use of planning data would be significantly simplified. Currently such a system does not exist, and the planning data must be collected from a number of different sources. This section will focus on where the required data is found in the Statoil system.

The lists given in Appendix A gives an overview of all the configuration data required by Drilltronics, from which source the data is found, and the suggested update frequency of the data. Much of the configuration data is seen not to be available in any of the main data sources, and may be gathered from other databases or even from other companies.

4.3.1 Rig configuration data

Rig and drilling machinery data generally requires updates only before the drilling operation is started. The exception is the mud pumps, which require data updates every time the pump liners are changed. Currently the drilling machinery data is scattered and it may be time-consuming to gather all the required data from the product vendors. Technical information for drilling machinery at the Statfjord installations has earlier been systemized in a technical handbook, but because the data is not being regularly updated it cannot be trusted. A database containing the required drilling machinery data from offshore installations and floating vessels of interest would greatly simplify the data gathering procedure for drilling machinery data. The rig configuration data may then be imported directly into the configuration editor when a rig is selected. This would simplify the job and be time-saving for the person responsible for entering rig configuration data. For this system to be efficient and reliable the database must be kept updated, preferably as a corporate procedure following every machine replacement. Rig data should anyway be validated before every operation commencement in case of non-registered drilling machinery replacements.

Data sheets for pump output with different liner sizes exist and are distributed by the vendor. If the required details from the data sheets are entered in the automated drilling system prior to the operation it will be necessary only to choose the correct liner size in the configuration editor during the drilling operation.

4.3.2 Wellbore architecture

The planned casing design is found in the drilling program. The source is an Excel spreadsheet found in the well team site. EDM is also used as casing database, but the casing data in EDM for the analyzed wells are inaccurate. A casing tally in an Excel spreadsheet format is finalized a short time before the planned casing run, after section TD is determined. It is common that some casing components are exchanged during the casing run, and the casing tally is updated to the As Run casing tally shortly after the casing is set.

DBR is used as database for actual casing data. The casing summary written in DBR is seen to differ from the As Run casing tallies for some of the analyzed well sections (Table 4.2). Therefore it is important to manually check the casing tallies to get the correct values at this time.

4.3.3 Wellbore trajectory

EDM is currently the official database for well positioning data in Statoil. The EDM database is continuously updated with new corrected surveys by the directional driller. DBR is also updated with wellbore trajectories every night by the drilling supervisor night. The survey data in DBR is however not official.

A number of surveys can be added for each wellbore in the EDM application Compass. The selected trajectory can be made up of a verified trajectory from a previous cased hole survey run, in addition to the current MWD trajectory. Default maximum survey interval for MWD is 30 m. When drilling close to live wells the maximum survey interval is 10 m. In harmless situations it is accepted to have a 100 m survey interval at sporadic occurrences. The necessary sampling rate for Drilltronics is considered to be once every stand, with a necessary accuracy of 0.05° and 0.1° for inclination and azimuth (*Sensor requirement for automated drilling*, n.d.). If the trajectory is not updated with survey stations, Drilltronics uses the planned trajectory for wellbore calculations.

Planned wellbore surveys may be updated in the middle of a drilling operation. Therefore it would be a good idea to regularly verify that the planned trajectory is in use.

The procedure for entering trajectory data in Compass is well established in Statoil. The author has however experienced that the directional data is not always updated in EDM even after several survey stations, and sometimes the DBR is updated before EDM. Since EDM is the official Statoil survey database the procedure of updating EDM after each survey station should be clarified for the directional driller. This must be done manually as long as the survey data needs corrections.

4.3.4 Geo-pressure and geo-thermal data

Geo-pressure gradients are provided by the geologist in the planning phase of the drilling operation. These gradients are seldom changed during the operation because the data is based on experience from previously drilled wells. The data is generally known to be very uncertain. Therefore Leak-off tests (LOT) are often performed after drilling through the casing shoe to measure the real fracture pressure at the casing shoe, where the risk of drilling induced fractures usually is the highest. Sometimes a Formation Integrity Test (FIT) is taken instead of a LOT to avoid breaking the formation.

Geo-thermal data is also provided by the geologist and are usually based on experience.

4.3.5 Drill string

The BHA proposals presented in the drilling programs and the DOPs are made by the service provider. The descriptions given do not contain the required details for accurate wellbore modeling. A more detailed description of components with complex pressure loss coefficients such as RSS and MWD is required. Such descriptions are given by the product vendor. The pressure loss graphs from Baker Hughes in Figure 4.2 shows that the pressure loss from a MWD tool is dependent on flow rate, mud weight and the properties of the component.

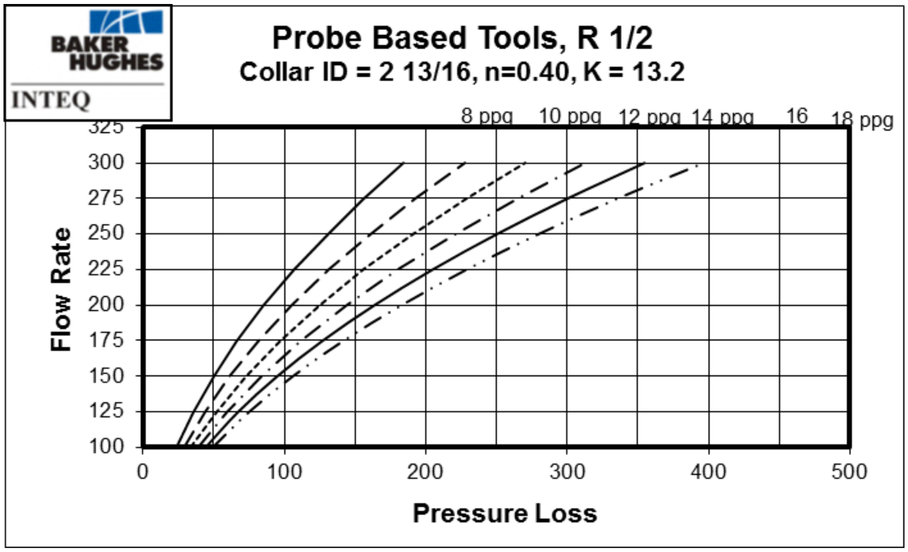


Figure 4.2 Example of pressure loss graph for MWD equipment (Randall, 1998).

The directional driller has a responsibility for the BHA and makes the final BHA tally in cooperation with the assistant driller. The new tally is approved by the drilling supervisor and is during the night updated in DBR.

4.3.6 Drilling fluid

The list of ingredients in the planned drilling fluid (shown in App. B.3) is provided by a service company. The density and rheology for the planned drilling fluid which is entered in the EDM application “Wellplan” is often based on previously drilled wells where a similar drilling fluid has been used. This may cause uncertainty in the planned drilling fluid parameters.

The mud logger takes thorough measurements of the drilling fluid with a frequency up to four times a day during the drilling operation. The measured data is however made available through the daily drilling report only once every day. The results from the data evaluation in Section 4.4.4 indicates that an update frequency of one each day will in some situations give large changes mostly because of the density which can change rapidly during drilling. Density measurements are additionally performed every hour in the mud inlet and outlet.

4.4 Evaluation of planned and actual configuration data for Statfjord wells

Data from the Activity Report, the DOPs and DBR of three recently drilled wells in Statfjord were analyzed to find in what extent well parameters change as the drilling operations develop.

4.4.1 Trajectory

The trajectory is planned to land in the original geological target with a given inclination and azimuth. Sometimes also intermediate targets are introduced to keep the drilling path within the target zone. Some deviations are normally permitted and a polygon called the Driller's Target is normally specified that account for the geophysical, geological and mechanical uncertainties. The actual trajectory is therefore allowed to slightly deviate from the planned trajectory.

Figure 4.3 **-** Figure 4.5 show comparisons of the planned and actual trajectory for three recently drilled wells at Statfjord C. The tables indicate that the actual trajectory may deviate from the planned well path, which implies that a process model may need updates during the drilling phase. Values for the following graphs are found in Appendix C.1.

C-39 A

The wellbore trajectory plan for C-39 A was changed after the drilling program, and the kick-off point was moved 220 meters down the well, as shown in Figure 4.3. The last trajectory plan from EDM is relatively close to the actual trajectory.

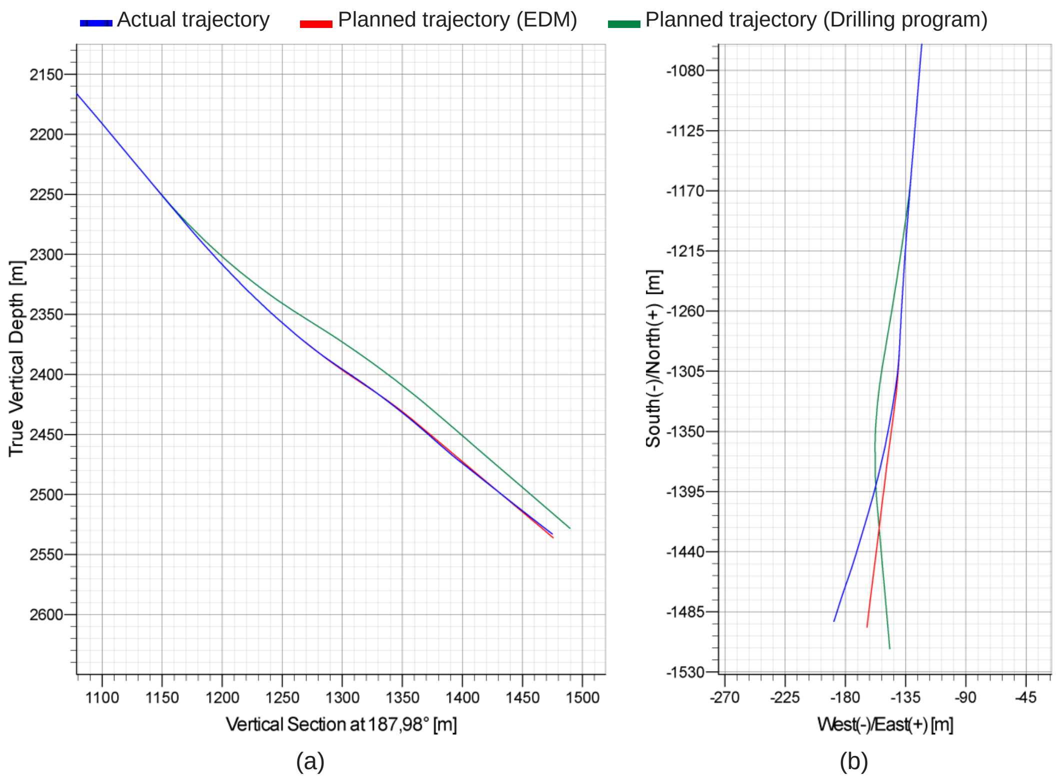
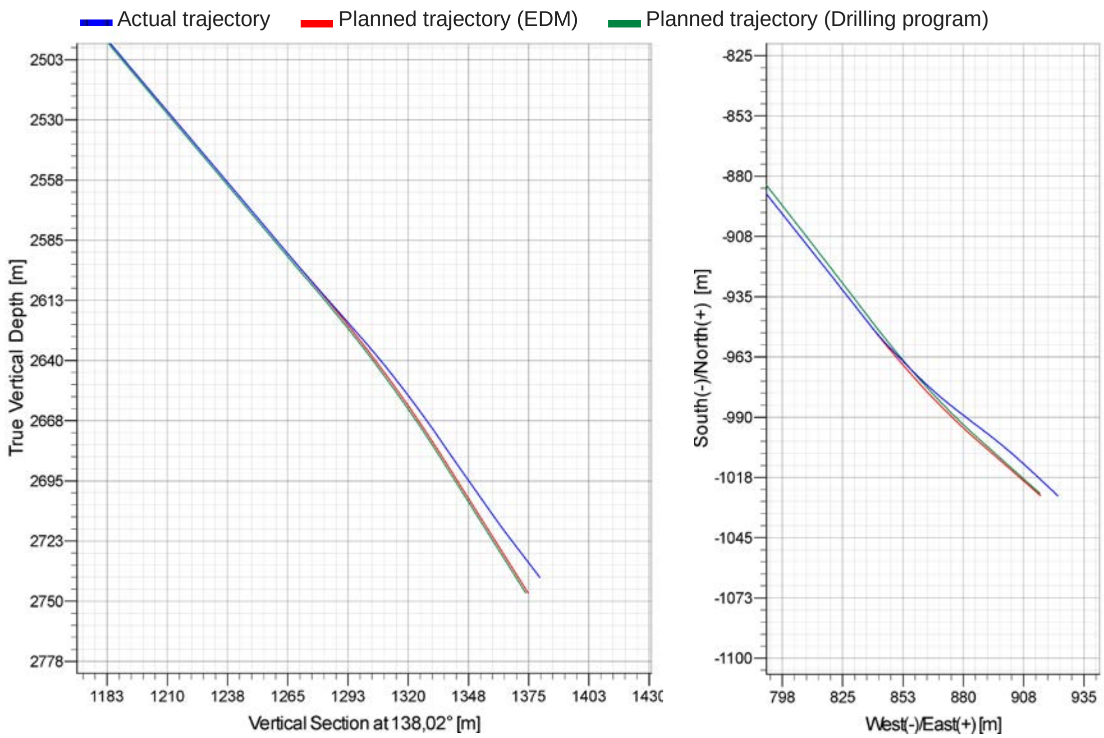


Figure 4.3 C-39 A. . Left: Section view of planned and actual trajectory. Right: Plan view of planned and actual trajectory. Blue: Actual trajectory. Red: EDM Final Planned trajectory. Green: Drilling program trajectory.

C-13 A

The actual trajectory is close to the planned trajectories. A new wellbore survey was run after the drilling program trajectory plan was made, resulting in the slight deviations along the main wellbore.

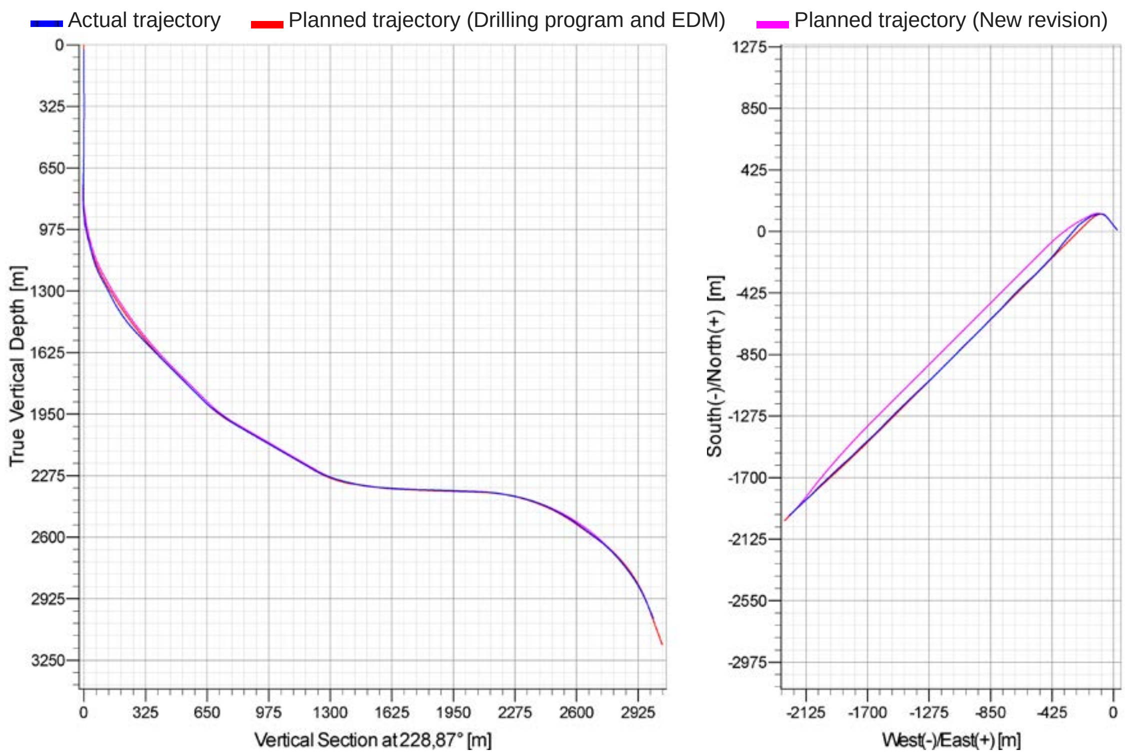


(a) (b)

Figure 4.4 C-13 A. Left: Section view of planned and actual trajectory. Right: Plan view of planned and actual trajectory. Blue: Actual trajectory. Red: EDM Final Planned trajectory. Green: Drilling program trajectory.

C-9 AT2

The trajectory plan from the drilling program is the same as the principal planned trajectory in EDM. There are however new revisions in EDM which are still marked as prototype. The principal plan will always be the one that is selected for the real operation. The pink curve in Figure 4.5 illustrates the last revision of the trajectory in EDM. This trajectory is seen to strongly deviate from the actual trajectory. The actual trajectory is however very similar to the principal planned trajectory.



(a) (b)

Figure 4.5 (a) Section view and (b) Plan view of planned and actual trajectories of C-9 A.

4.4.2 Wellbore architecture

The planned casing design is found in the Drilling program, but is originally planned in the Stresscheck/CasingSeat applications of the EDM Suite. The casing design is finally plotted manually in Excel and copied to the activity program.

Three wells at Statfjord were evaluated to find differences between the planned and actual well design data. The planned depth of the casing shoe is often approximate and is often based on a desire to reach a particular formation. Drilling problems may also affect the depth of the casing shoe. The casing shoe depth is thus quite variable. A change in casing shoe depth will affect the depth were a liner is hung off. This will result in a different well diameter and annulus volume, which will affect mechanical and hydraulic calculations.

Table 4.2 gives a summary of details of planned and actual casing design for three wells at Statfjord. The planned casing design is found in the Drilling Program, while the actual design is found in DBR. Variations from planned to actual design are found in most sections in terms of length. In C-39 A the casing windows is milled 220 meters lower than the plan from the Drilling Program. The planned and actual casing designs of C-13 A are very similar. C-9 A shows a significant change for the 13 3/8” x 14” section, which is 40 meters shorter than planned due to a restriction during the casing run at 2112 m.

Table 4.2 Planned and actual casing runs for three wells at Statfjord.

Well	Hole size	Planned / actual	Casing type	Casing grade	Weight [lb/ft]	Conn. type	From depth m MD	To depth m MD
C-39 A	8,5”	Planned (Drilling Program)	7” liner	13 Cr-80	32	Vam Top	2560,0	2934,0
		Actual (DBR)	7” liner	13 Cr-80	32	Vam Top	2783,4	2923,6
		Actual (Casing tally)	7” liner	13 Cr-80	32	Vam Top	2783,8	2924,0
C-13 A	8,5”	Planned (Drilling Program)	7 5/8” liner	13 Cr-S110	33,7	Vam Top	2917,0	3085,0
		Actual (DBR)	7 5/8” liner	13 Cr-S110	33,7	Vam Top	2901,6	3079,6
		Actual (Casing tally)	7 5/8” liner	13 Cr-S110	33,7	Vam Top	2911,0	3088,0
C-9 A	17,5”	Planned (Drilling Program)	13 3/8” x 14”	Q-125 / 13Cr80	72 / 114	Vam Top	28,2	1850,0 / 2148,0
		Actual (DBR)	13 3/8” x 14”	Q-125 / 13Cr80	72 / 114	Vam Top	28,2	1797,7 / 2107,2
		Actual (Casing tally)	13 3/8” x 14”	Q-125 / 13Cr80	72 / 114	Vam Top	28,2	1804,4 / 2107,2
C-9 A	12 ¼” x 14”	Planned (Drilling Program)	10 ¾” x 9 5/8”	13Cr110	65,7 / 53,5	Vam Top	2098	2668 / 4202
		Actual (DBR)	10 ¾” x 9 5/8”	13CrS110	65,7 / 53,5	Vam Top	2054,3	2670,0 / 4212,0
		Actual (Casing tally)	10 ¾” x 9 5/8”	13CrS110	65,7 / 53,5	Vam Top	2054,3	2670 / 4212,0
C-9 A	8 ½”	Planned (Drilling Program)	7”	13Cr80	32	Vam Top	4152,0	4820,0
		Actual (DBR)	7”	13Cr80	32	Vam Top	4166,4	4825,0
		Actual (Casing tally)	7”	13Cr80	32	Vam Top	4166,4	4825,0

4.4.3 BHA

The Bottom Hole Assembly is planned to obtain an optimized weight on bit by using an appropriate length of drill collars and HWDP. MWD and LWD Equipment also take up a bit of the BHA, and stabilizers for directional control may add torque to the system. The composition of the actual BHAs can be different from the planned design found in the Drilling Program. The reason for modifications to the BHA setup may be due to new experiences during the drilling operation, change of plans before the operation or due to limited supply of equipment. In long or particularly difficult sections, several BHA runs may be used during a single section. The planned BHA is set up by a service company and later copied to the Drilling Program. The actual BHA in use is entered in the daily report by the Company Supervisor Night. All the BHAs that were run in an operation are also entered in separate BHA reports in DBR.

Information about the planned and actual BHAs for the three analyzed Statfjord wells is presented in Appendix C.2. The analysis of the three wells showed that the actual BHA was different from the planned BHA in the Drilling Program in all cases. The BHAs from the Drilling Program are dated up to more than three months prior to the BHA run, and frequently the differences in terms of components and lengths are significant. The difference in length of the entire BHA (including HWDP) varied with up to 60 m, where the length of the MWD/LWD, drill collar and HWDP sections seems very variable. The BHAs from the DOPs tend to be much more accurate than the BHAs from the drilling program, but slight differences are frequent. In the three sections of C-9 AT2 that were planned with an RSS, the planned RSS device was changed to a different type when run.

The 12,25”x14” section of C-9 A was drilled with a 12 ¼” bit and a 12 ¼” x 14” under-reamer placed 42 meters above the bit. The under-reamer itself and the resulting two simultaneous hole dimensions complicates the hydraulics calculations. The automated drilling system cannot know whether the under-reamer is expanded or contracted. The 12 ¼” x 14” under-reamer used in the C-9 A well was activated by dropping a ball. A significant pressure increase appeared after pumping 10 m^3, which meant that the reamer was expanded. In this case the automation system would require a manual update of the hole proportions. The under-reamer had 4 nozzles, and though involving only 3 % of the total area of the nozzles on the bit and the reamer, the extra mud flow must also be accounted for in the hydraulic model. A discussion on automated systems and hole openers is found in (Cayeux et al., 2013).

Although only one planned BHA tally is given in both the drilling program and the DOP per section for C-9 AT2, the 17 ½” section required five drilling BHA runs. Most of the BHAs are very similar, but changes in setup and bit occurred. Total BHA and HWDP length varied from 156,00 m to 182,37 m. The actual BHA tally was found to be reported differently in the Daily Report and in the BHA Report of DBR, and the latter contained significant errors for the 8.5” and 6”x7” sections of well C-39 A.

4.4.4 Drilling fluid

The properties of the drilling fluid have a major influence on the pressure in the well. The main determinants of pressure loss during fluid flow are the fluid velocity and the fluid viscosity. The pressure loss due to fluid flow is added to the static mud weight to find the equivalent pressure in the well, or more commonly ECD (Equivalent Circulating Density).

C-39

8 ½" SECTION

Figure 4.7 shows a strong deviation in rheology between planned and actual values. The mud weights in Figure 4.6 show quite good correlations between planned and actual values, but there is a slight deviation between the planned mud weight and the two first measurements after drilling commencement. The plot shows that the last density measurement before drilling start is equal to the first measurement after start of drilling, which means that the previous density measurement can be used. Flow rate: 2100 l/min.

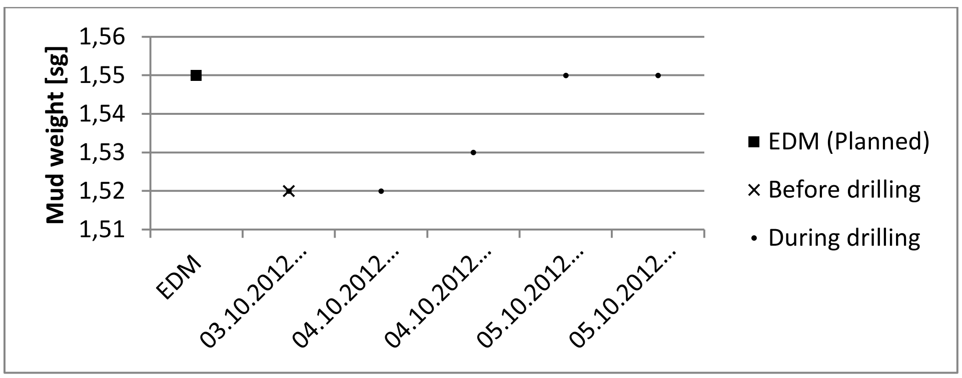


Figure 4.6 Planned (EDM) and actual mud weights from C-39 A 8 ½" section.

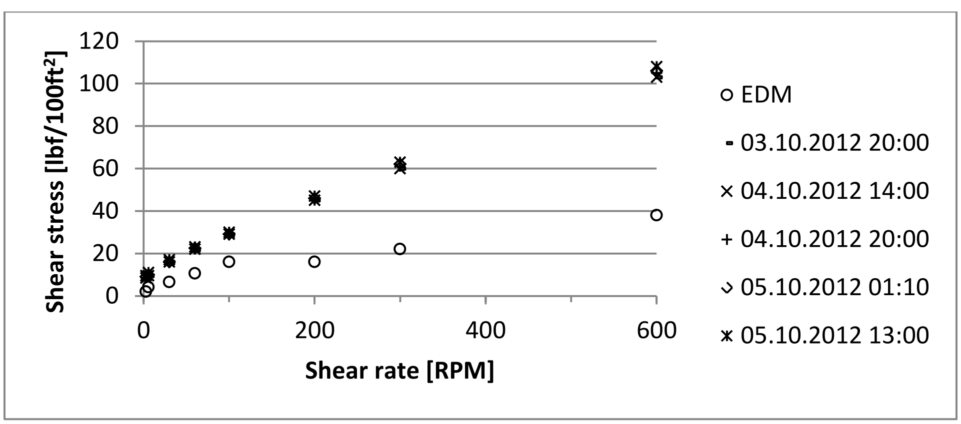


Figure 4.7 Planned (EDM) and actual rheology from C-39 A 8 ½" section.

6” X 7” SECTION

Figure 4.8 shows that the EDM mud weight is equal to actual mud weight during the entire section. It is however noted in the Daily Drilling Report that a 1.40 sg mud weight was measured during an unknown time frame between 09.10.2012 08:00 and 15:00. This is not captured by the mud weight measurement at 14:00, and the mud weight was apparently reduced again by then. The viscosity measurements in Figure 4.9 shows that the planned rheology is very accurate compared with the two latest actual measurements. 1250 l/min.

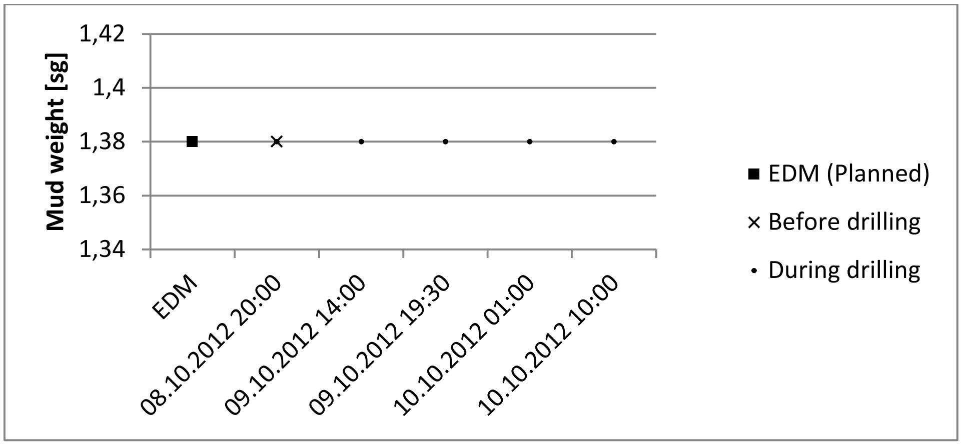


Figure 4.8 Planned (EDM) and actual mud weights from C-39 A 6” x 7” section.

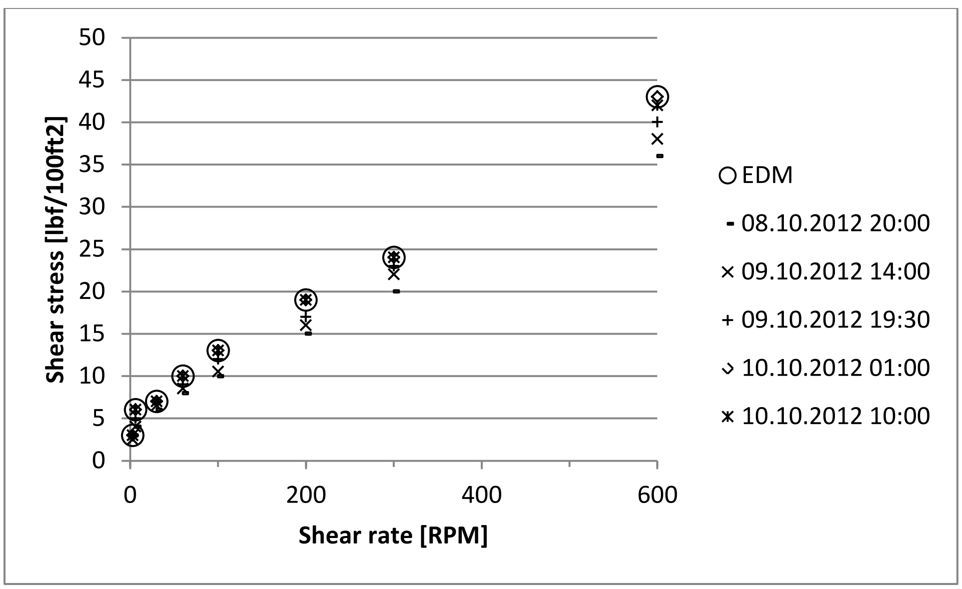


Figure 4.9 Planned (EDM) and actual rheology from C-39 A 6” x 7” section.

C-13

8 ½" X 9 ½" SECTION

There is a very good agreement between planned and actual mud weights and mud rheology in the 8 ½" x 9 ½" section of C-13 A as seen in Figure 4.10 and Figure 4.11. 2100 LPM

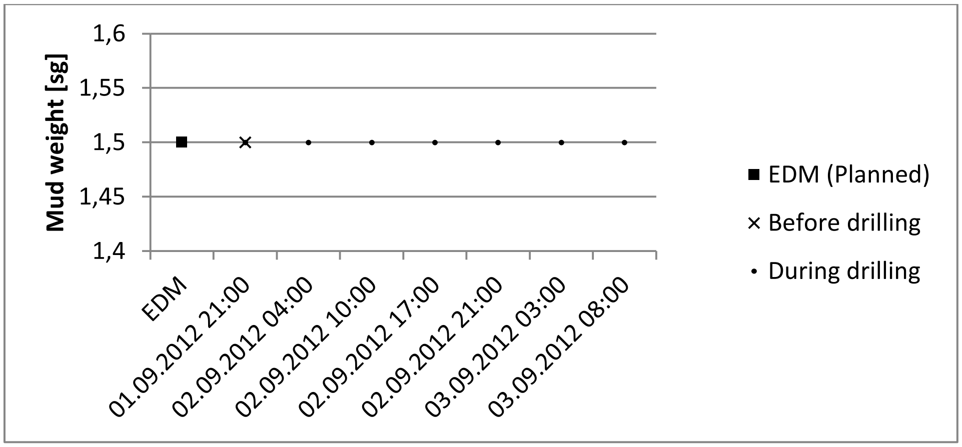


Figure 4.10 Planned (EDM) and actual mud weights from C-13 A 8 ½" x 9 ½" section.

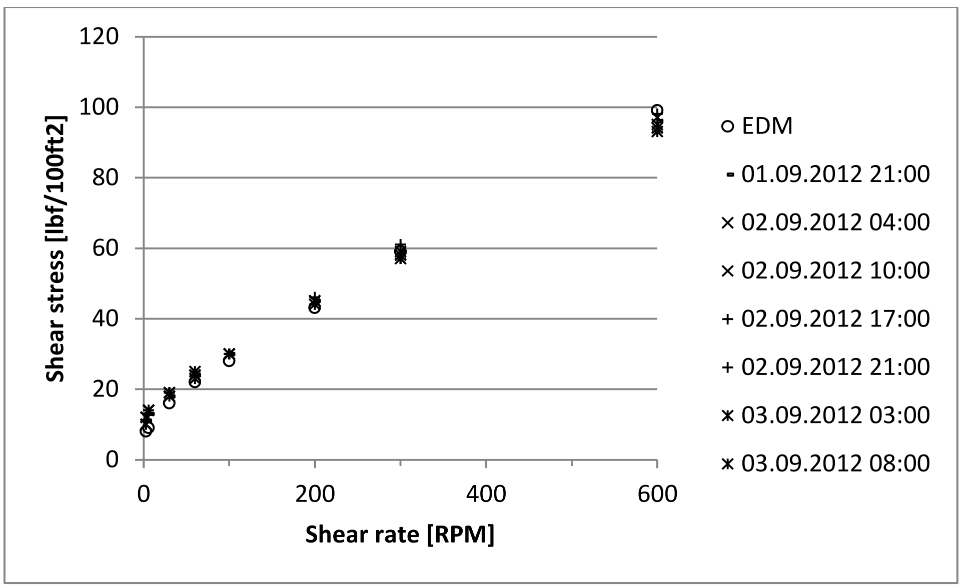


Figure 4.11 Planned (EDM) and actual rheology from C-13 A 8 ½" x 9 ½" section.

6 ½" X 7 ½" SECTION

Drilling is started at 08.09.2012 09:45. The mud weight has been reduced to the planned value and reported in DBR the day before drilling started. The planned mud weight value is equal to the actual values. 1100 l/min.

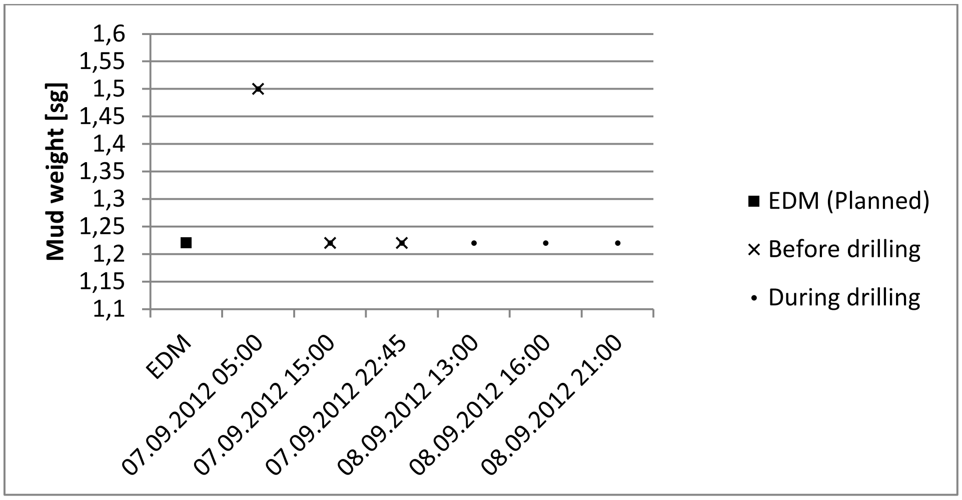


Figure 4.12 Planned (EDM) and actual mud weights from C-13 A 6 ½" x 7 ½" section.

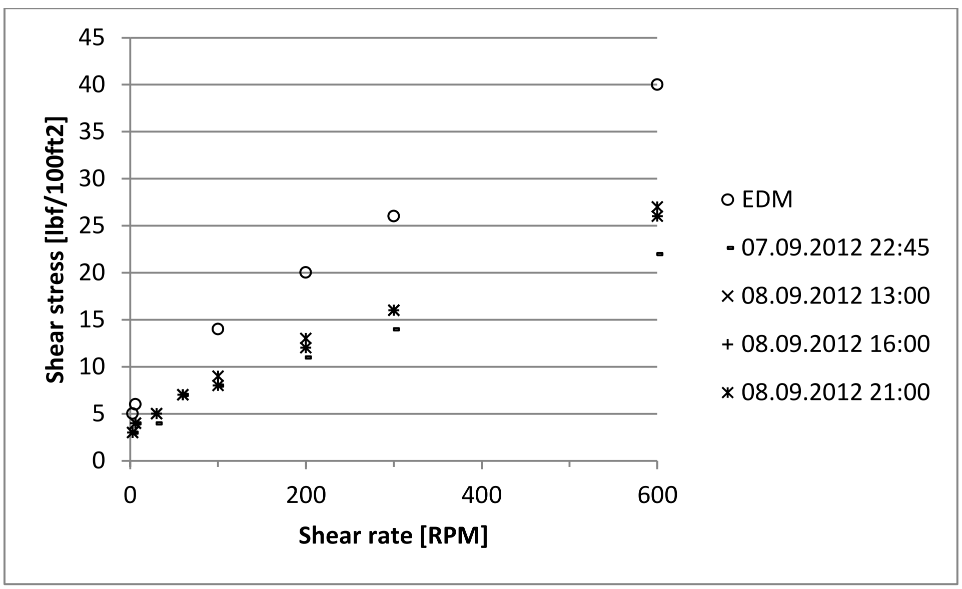


Figure 4.13 Planned (EDM) and actual rheology from C-13 A 6 ½" x 7 ½" section.

C-9

17,5" SECTION

During drilling of the 17 ½" section the mud was weighted up in two steps from 1.20 sg through 1.38 sg and finally to 1.46 sg. The two planned values of mud weights in EDM correspond accurately with the first and last actual mud weights respectively, but the weight-up is not captured. In addition there is no information telling which of the values correspond to the first and the last mud weight. The planned fluid viscosities have very similar values, and both have a relatively good fit with the last measurements, even though there is a wide discrepancy between the first and last measurements.

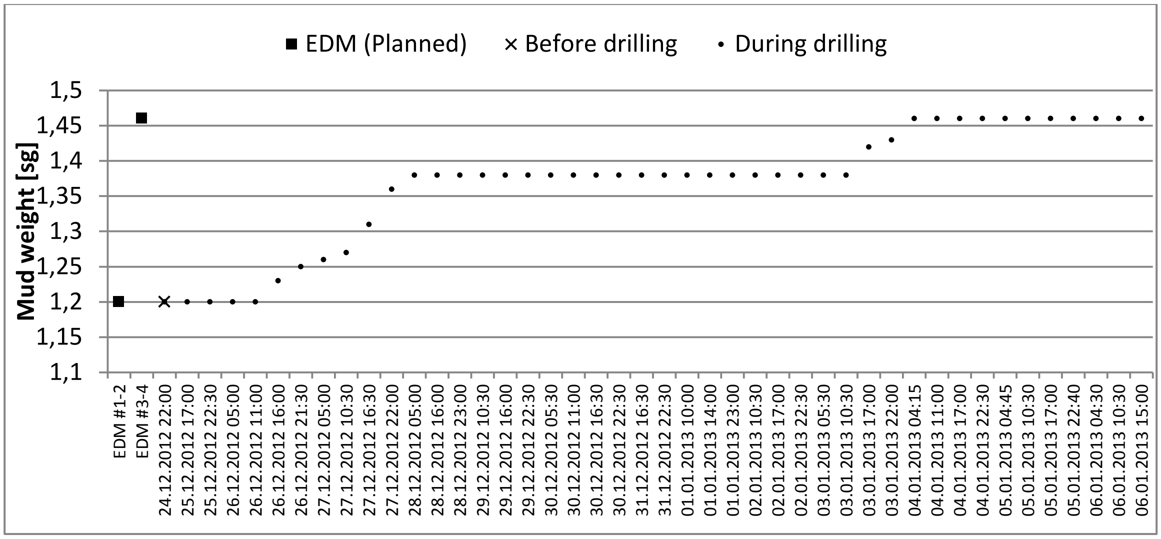


Figure 4.14 Planned (EDM) and actual mud weights from C-9 A 17 ½" section.

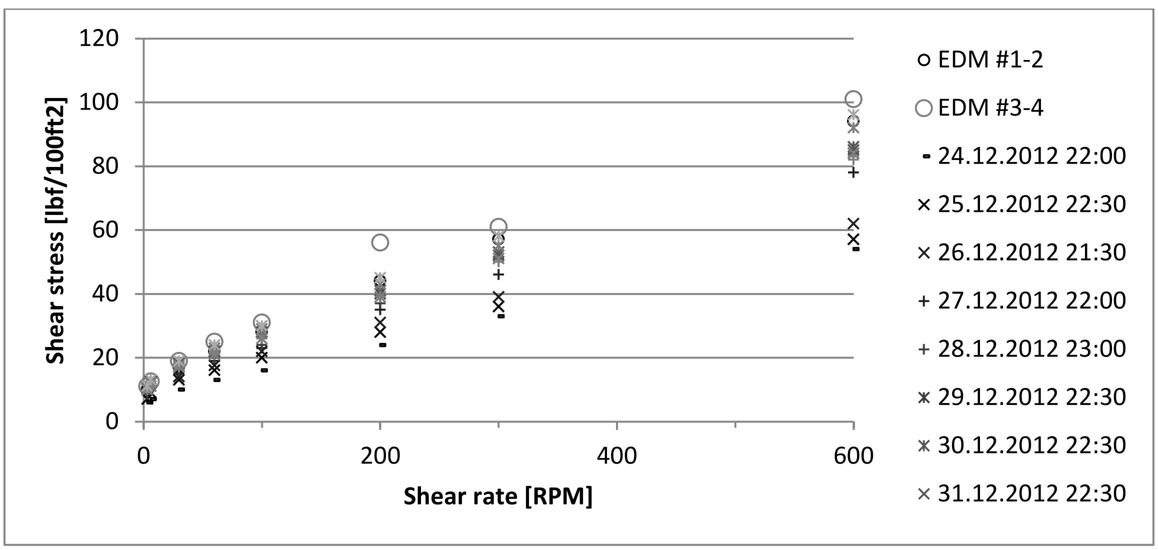


Figure 4.15 Planned (EDM) and actual rheology from C-13 A 17 ½" section.

12 ¼” X 14” SECTION

There are two different drilling fluids stored for C-9 AT2 12 ¼” x 14” section in EDM, where only one (EDM #2) corresponds to the actual mud weight measurements. EDM #2 is slightly off regarding the mud weight the two first days of the section, see Figure 4.16 . The last measurement before drilling start is equal to the first days of drilling. The actual shear stress of the drilling fluid increases during drilling, as can be seen in Figure 4.17. Both EDM values are close to an average of the viscosity measurements.

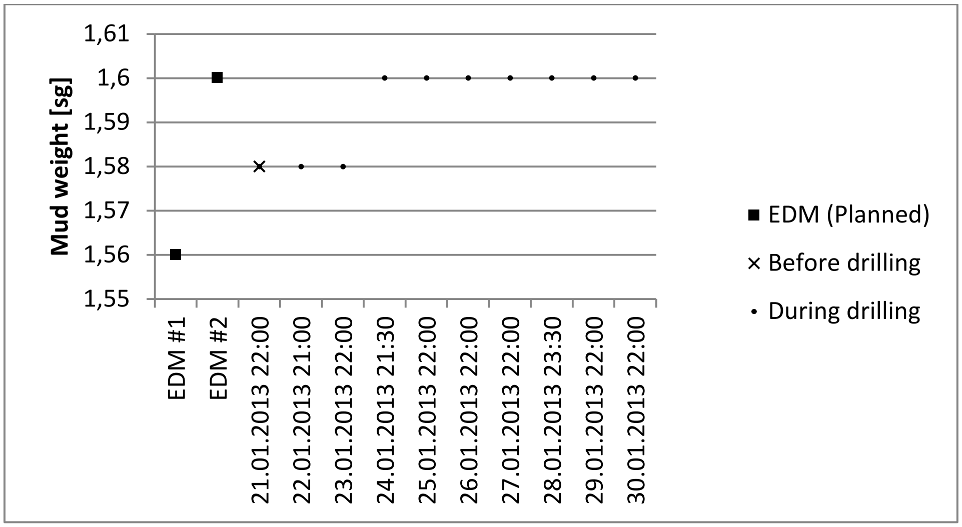


Figure 4.16 Planned (EDM) and actual mud weights from C-9 A 12 ¼” x 14” section**.**

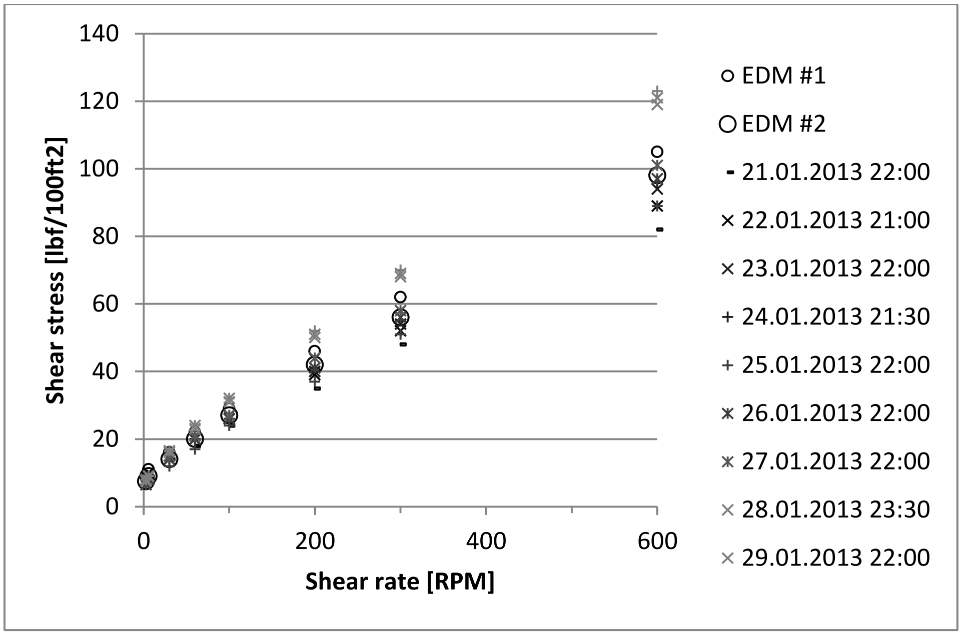


Figure 4.17 Planned (EDM) and actual rheology from C-9 A 12 ¼” x 14” section.

8 ½" SECTION

Figure 4.18 shows that all the mud weights measurements were equal during drilling of this section. The planned values and the measurements prior to drilling are also equal to the actual values. The Fann viscometer readings, shown in Figure 4.19, increase during drilling. The EDM #2 values are lower than close to all the measured values. The rheology values of EDM #1 are closer to an average of the actual values.

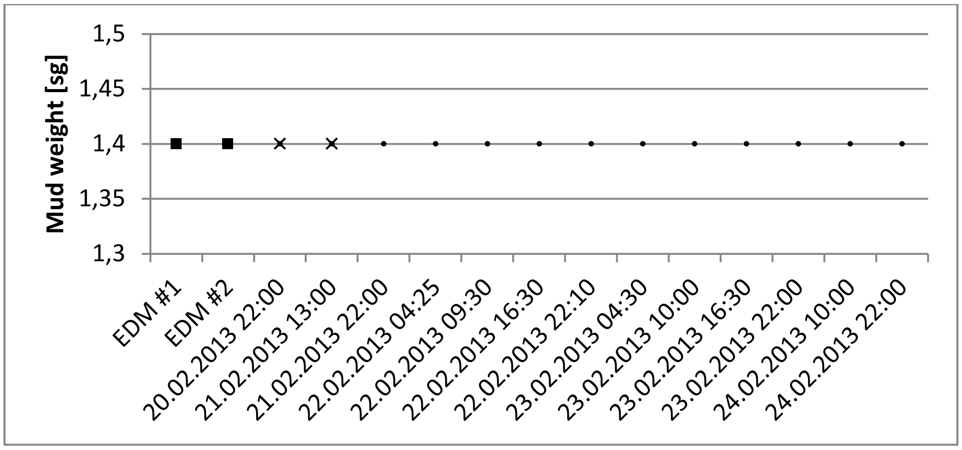


Figure 4.18 Planned (EDM) and actual mud weights from C-9 A 8 ½" section.

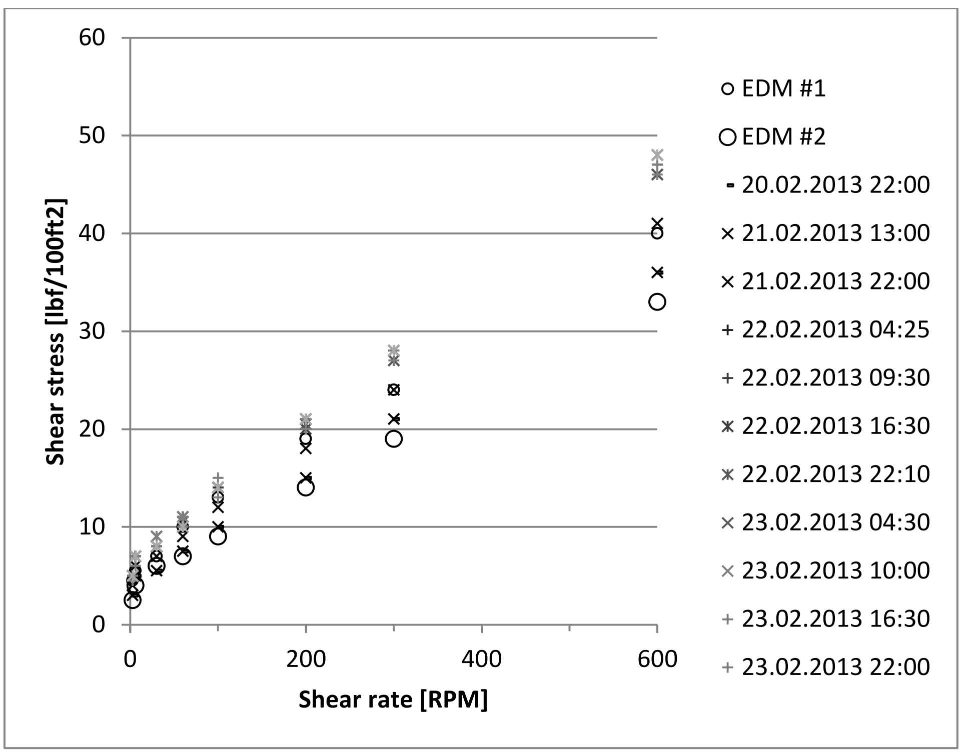


Figure 4.19 Planned (EDM) and actual rheology from C-9 A 8 ½" section.

6" X 7" SECTION

Figure 4.20 shows that both the planned mud weight value from EDM and the last measurement the day before drilling initiation are 0.1 sg lower than the actual values during drilling. The very last mud weight measurement before drilling is equal to the ones during drilling. The EDM rheology values, shown in Figure 4.21, are closer to the actual values during drilling than the last measurement from the previous day. The very last measurement before drilling is very close to the actual values during drilling.

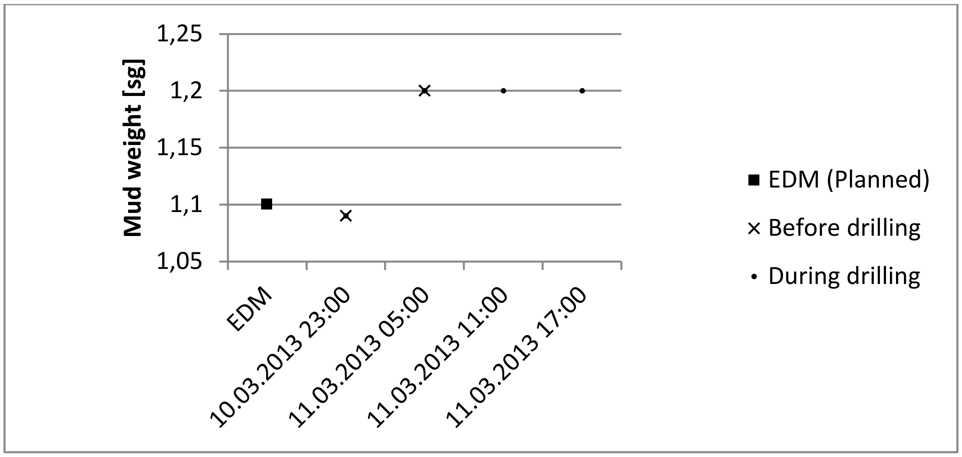


Figure 4.20 Planned (EDM) and actual mud weights from C-9 A 6" x 7" section.

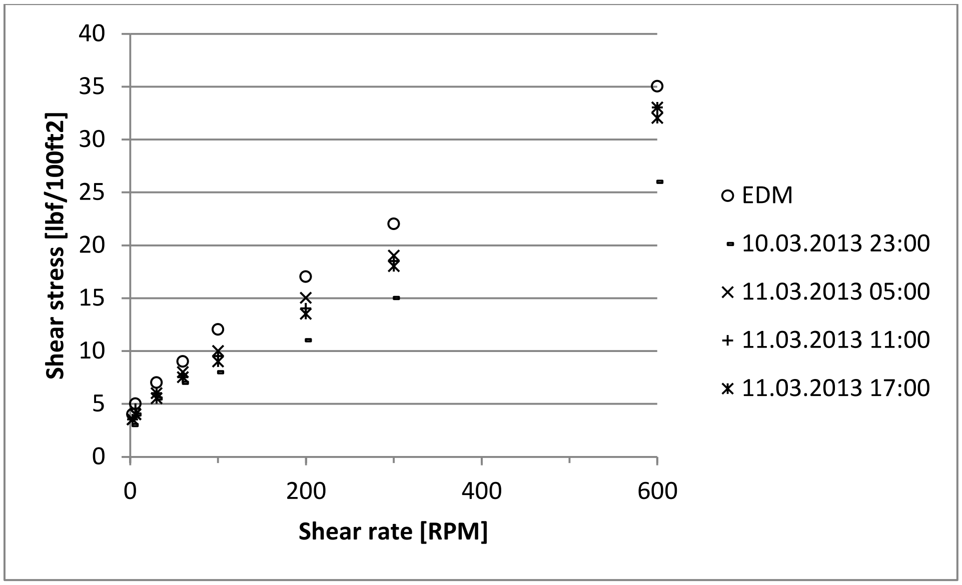


Figure 4.21 Planned (EDM) and actual rheology from C-9 A 6" x 7" section.

4.5 Analysis of planning data quality for wellbore modeling

The results from the data acquisition presented in Section 4.3 were used to do simulations in the drilling and well data analysis software, Wellplan, to compare the consequences of the difference between planned and actual configuration data that were found in Section 4.3. The calculation models used by Drilltronics are not the same as the Wellplan models. However, it is assumed that the relative values are adequate for getting an idea of the influence of the analyzed data for any general wellbore modeling software.

Some well sections were selected for analysis, and effects on both hydraulics and torque and drag were analyzed.

4.5.1 Trajectory

C-9 AT2 12 ¼” x 14”

The 12 ¼” x 14” well section of C-9 AT2 was selected for analysis because of the great length of this section. Drag charts were made in Wellplan for the planned and actual trajectory of C-9 AT2 12 ¼” x 14”. Drag charts are used to estimate hook load and surface torque with the bit at a varied depths. It is assumed that the planned trajectory is based on the actual trajectory from the surface to the 13 3/8” x 14” casing shoe. The drag charts are consequently corrected in Excel so that actual and planned torque and hook load are equal at this depth. The absolute values are therefore not correct, but the graphs are still assumed to be acceptable for a comparison.

Figure 4.22 and Figure 4.23 shows the actual trajectory from EDM and a corrected principal planned trajectory from EDM in vertical section view and in plan view respectively.

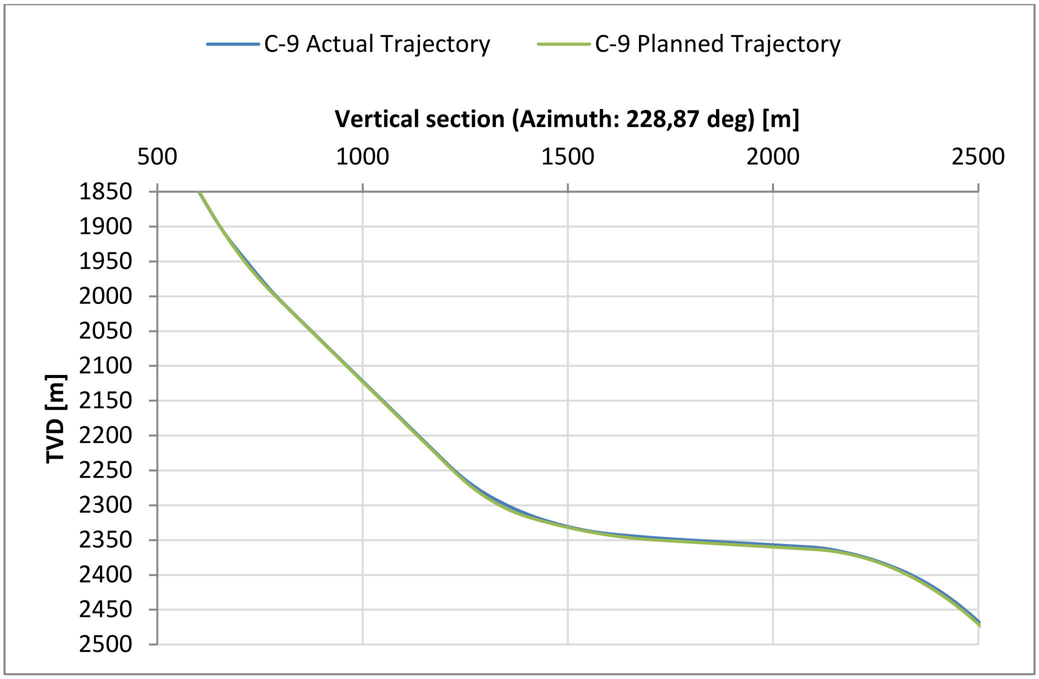


Figure 4.22 Vertical section view of C-9 AT2 12 ¼” x 14” trajectory. The planned values are corrected to equal the actual value at the 13 3/8” x 14” casing shoe at 1870 m TVD.

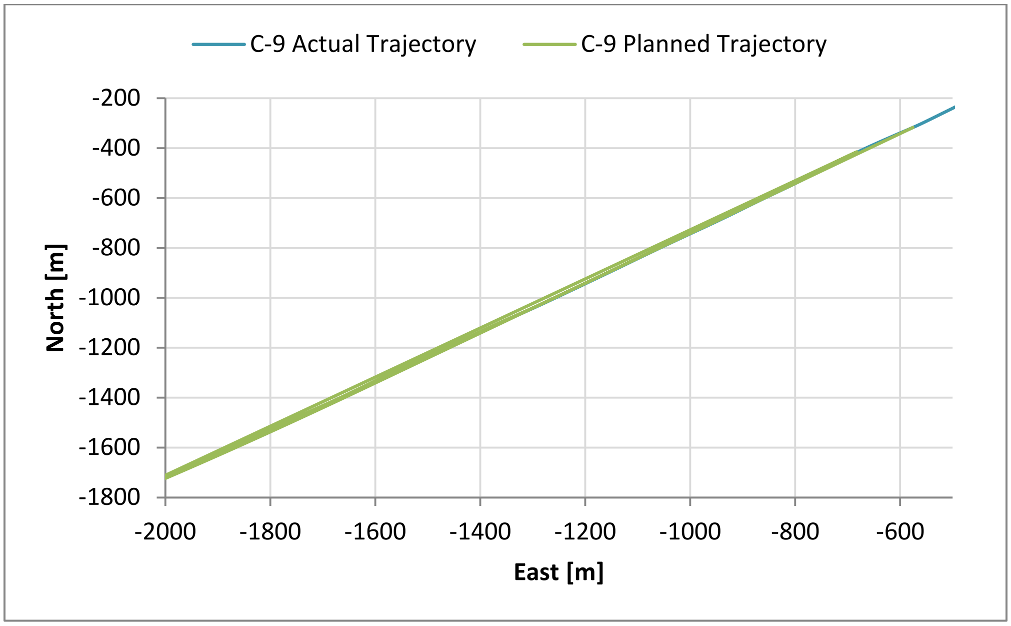


Figure 4.23 Plan view of C-9 AT2 12 ¼” x 14” trajectory. The planned values are corrected to equal the actual value at the 13 3/8” x 14” casing shoe at 1870 m TVD.

The results from the torque and drag simulations in Wellplan are presented in Figure 4.24 and Figure 4.25. The torque at depth is seen to vary for the planned and actual trajectories, and this may be caused by the absolute values of the dog leg severities along the well which varies for the planned and actual trajectory. The maximum difference, which is found at the maximum depth, is approximately 2000 Nm. The planned and actual hook load values are more similar to each other. The graphs for Tripping Out are slightly deviating from each other.

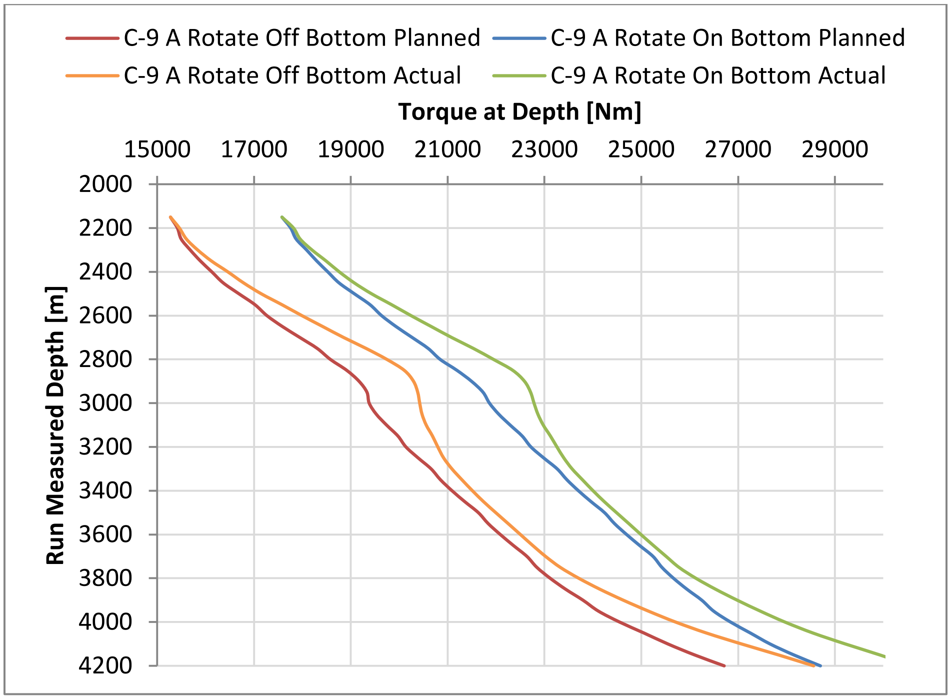


Figure 4.24 Surface Torque vs Run Measured Depth for planned and actual trajectories of C-9 AT2 12 ¼” x 14” section.

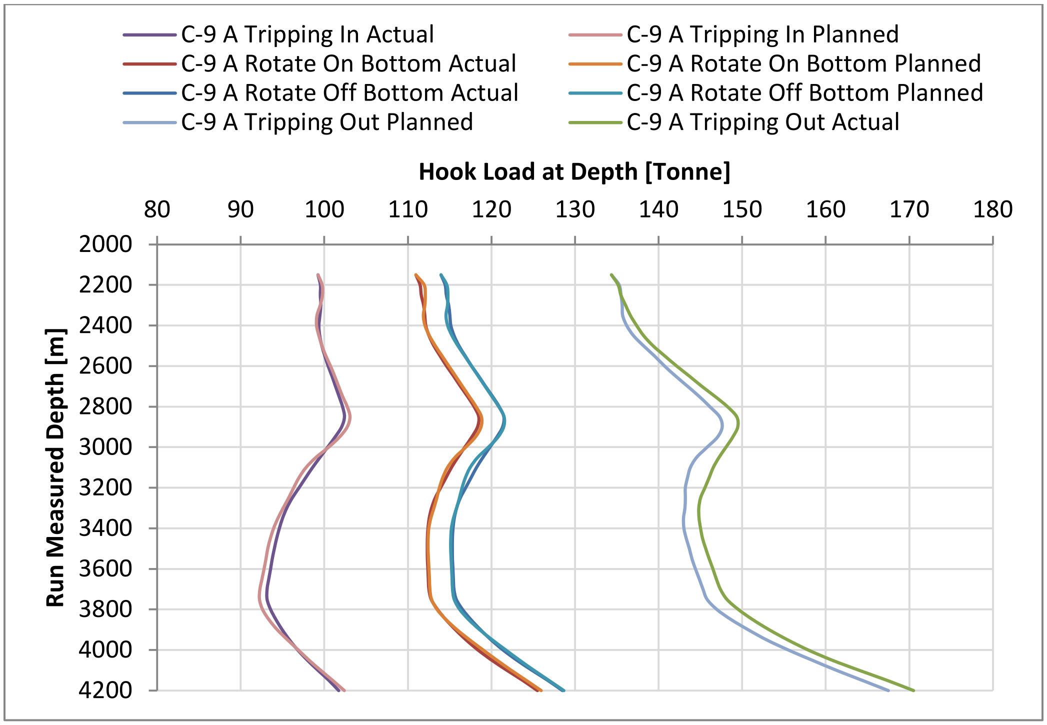


Figure 4.25 Hook Load vs Run Measured Depth for planned and actual trajectories of C-9 AT2 12 ¼” x 14” section.

4.5.2 BHA

C-13 A 8 ½” x 9 ½”

The C-13 A 8 ½” x 9 ½” BHA was selected for analysis because of the large differences found in the comparison of Drilling Program BHA, DOP BHA and Actual BHA. BHA information for comparison of planned and actual BHA data for this well can be found in Appendix C.2. Both hydraulics and torque and drag analyses were done to find the influence of the different BHA on wellbore models.

Figure 4.26 shows the influence of the BHAs from the Drilling Program, the 8.5” section Drilling DOP and the actual BHA on annulus ECD. The results show only a very small variation in ECD. The result from the actual BHA differs slightly from the planned BHAs even though it is the Drilling Program BHA that looks most different from the tally. The reason is in this case that the OD and length of the BHA components has an appreciable influence on ECD. For C-13 A the component with the most differences in length and OD is the HWDP (Heavy Weight Drill Pipe).

A slightly higher influence of the BHAs is found in the torque and drag analysis presented in Figure 4.27 and Figure 4.28. The results show that the short Drilling Program BHA gives the most different drill string torque and tension.

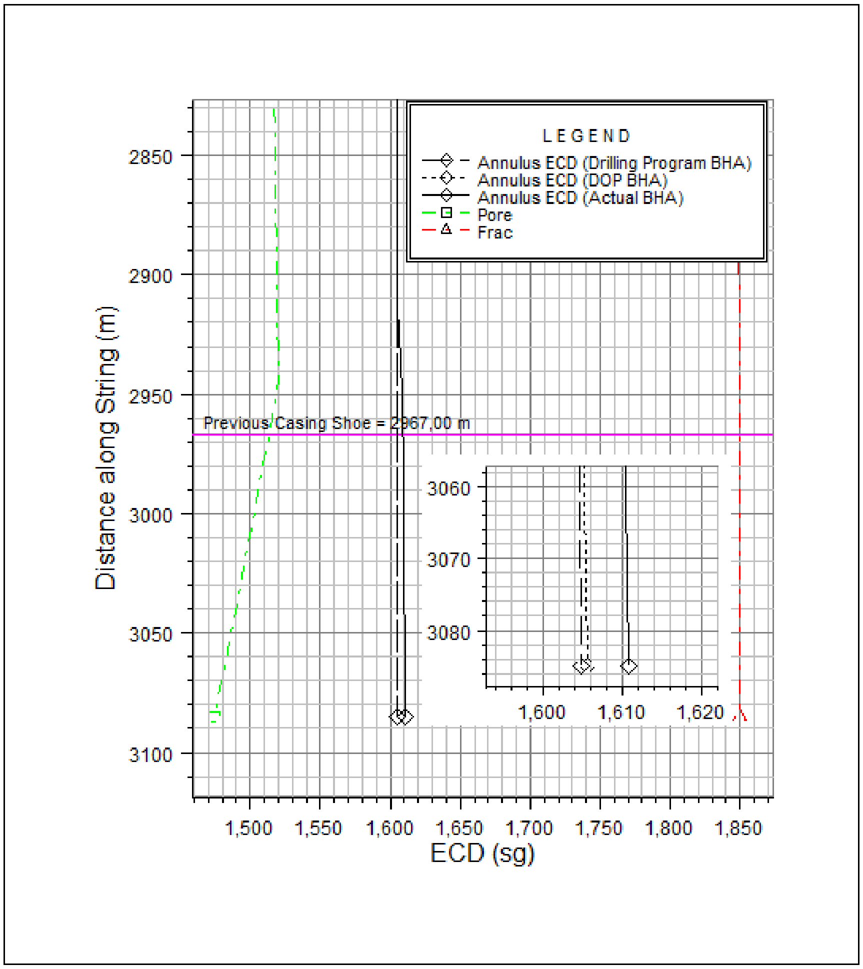


Figure 4.26 Comparison of the influence of BHAs from different planning stages on Annulus ECD on well C-13 A.

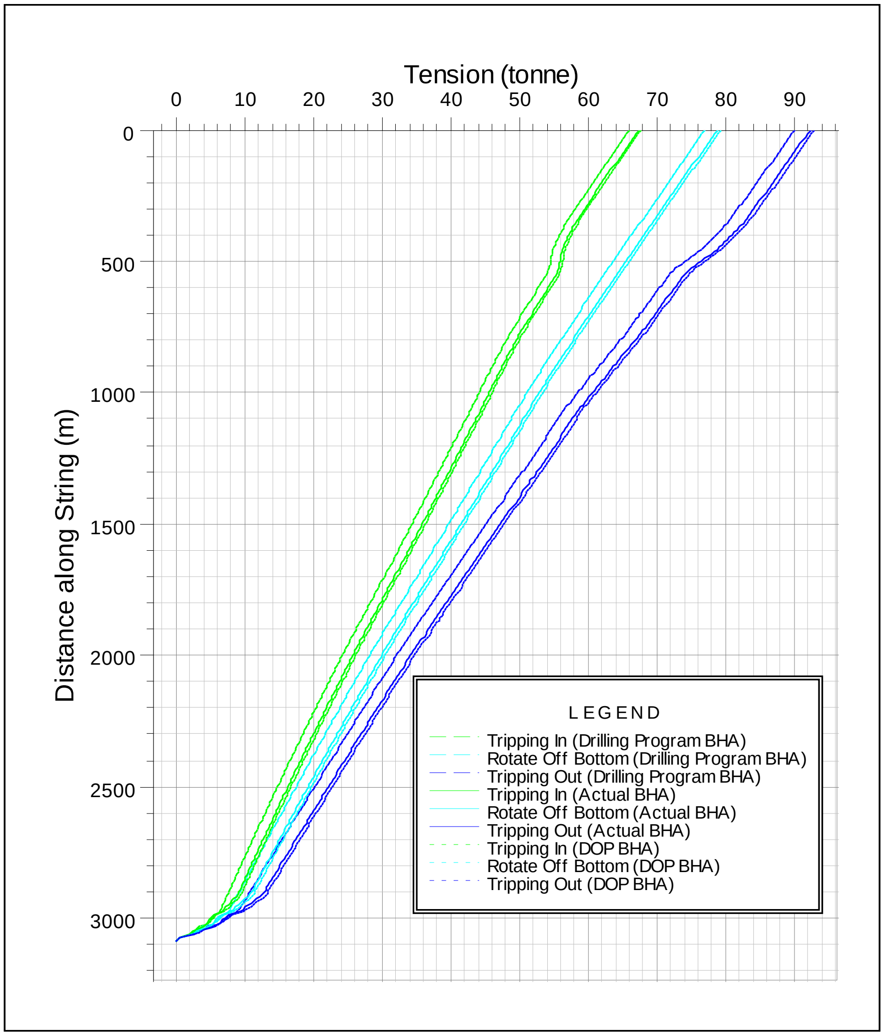


Figure 4.27 The influence of the BHAs from the Drilling Program, the 8.5" section Drilling DOP and the actual BHA on drill string tension for C-13 A.

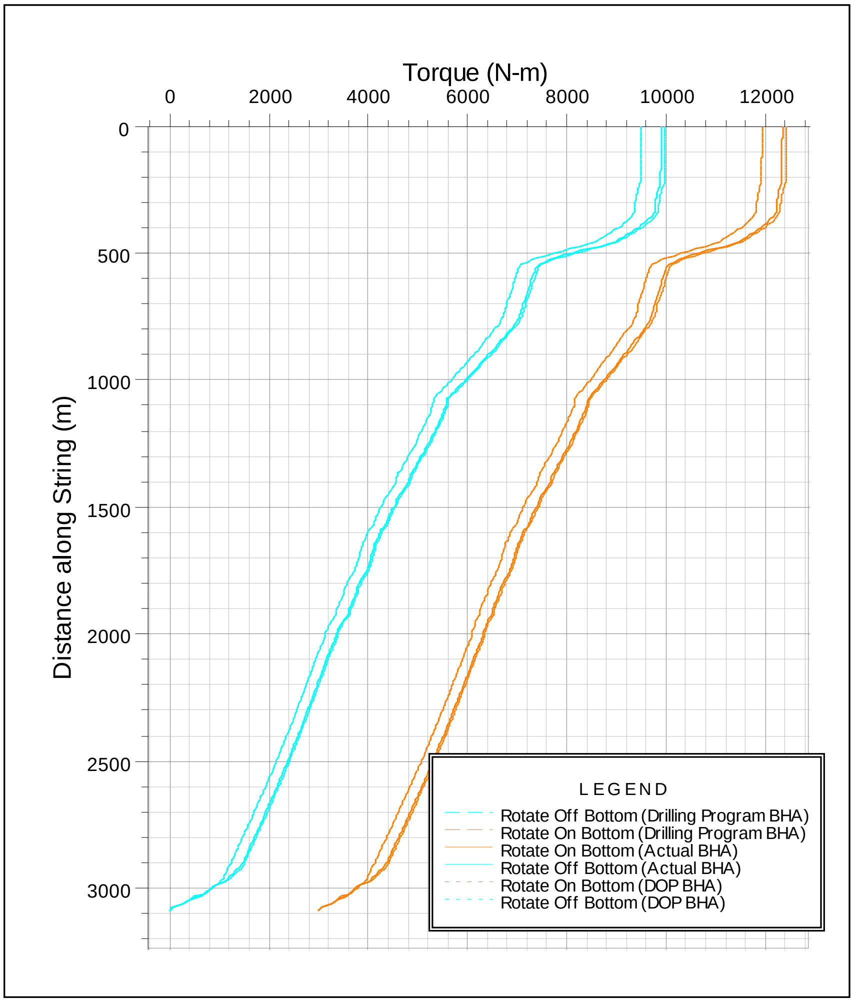


Figure 4.28 The influence of the BHAs from the Drilling Program, the 8.5” section Drilling DOP and the actual BHA on drill string torque for C-13 A.

C-13 A 6 ½” x 7 ½”

The same analysis as above was done on C-13 A 6 ½” x 7 ½” section because of the observed differences in MWD and collar length from planned to actual BHA tally (see Appendix C.2). As shown in Figure 4.29 - Figure 4.31, there are no observable differences in the performed Wellplan hydraulics and torque and drag analyses.

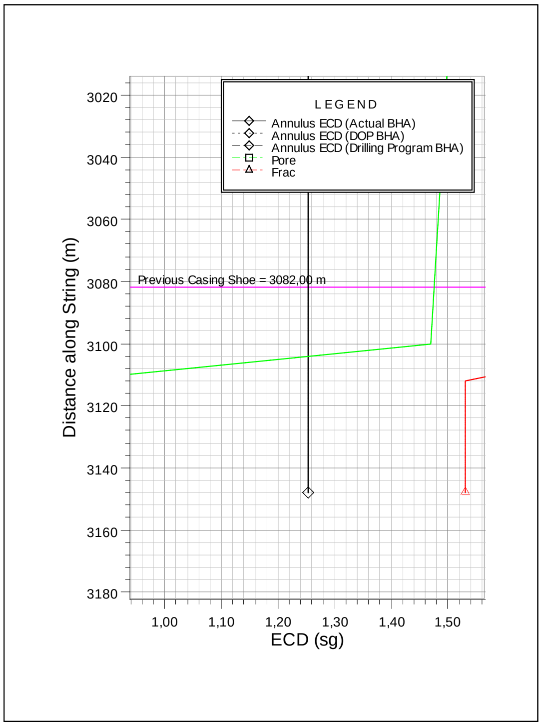


Figure 4.29 Influence of BHAs from different planning stages on Annulus ECD on well C-13 A 8½”x9½”.

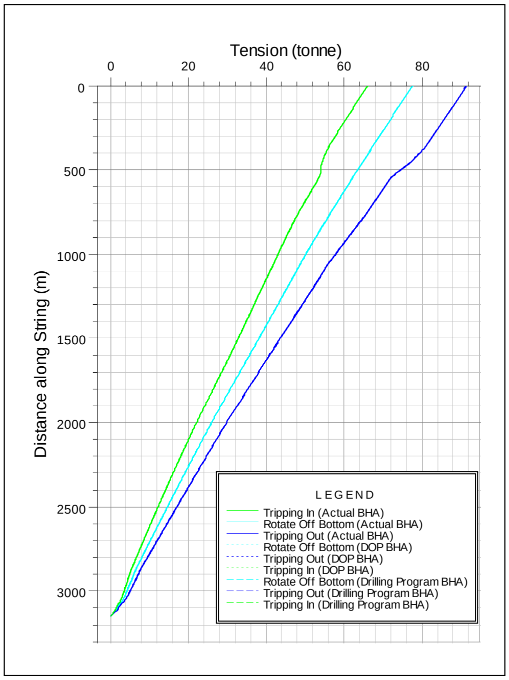


Figure 4.30 Influence of the BHAs from the Drilling Program, the 6 ½” x 7 ½” section Drilling DOP and the actual BHA on drill string tension for C-13 A.

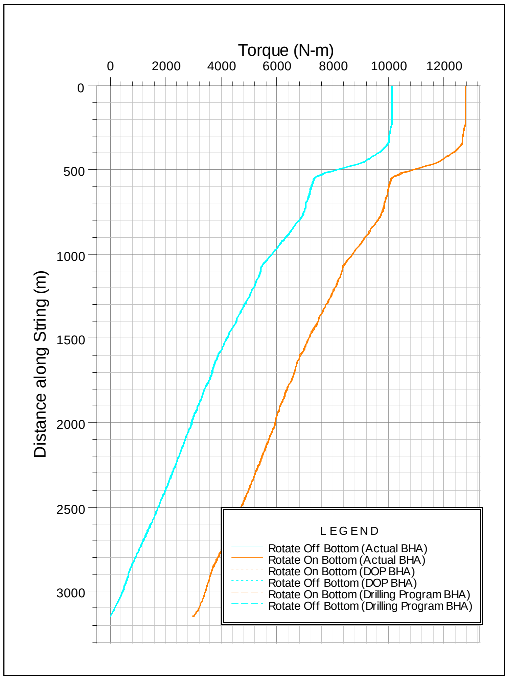


Figure 4.31 Influence of the BHAs from the Drilling Program, the 6 ½” x 7 ½” section Drilling DOP and the actual BHA on drill string torque for C-13 A.

4.5.3 Drilling fluid

C-39 A

The C-39 A 8 ½" section was selected for analysis because the rheological measurements strongly disagreed with the drilling fluid stored in EDM. The first density measurements also differed from the EDM. The resulting ECDs with a flow rate of 2100 l/min is shown in Figure 4.32. The large error in rheology is seen to have a large influence on hydraulics calculations.

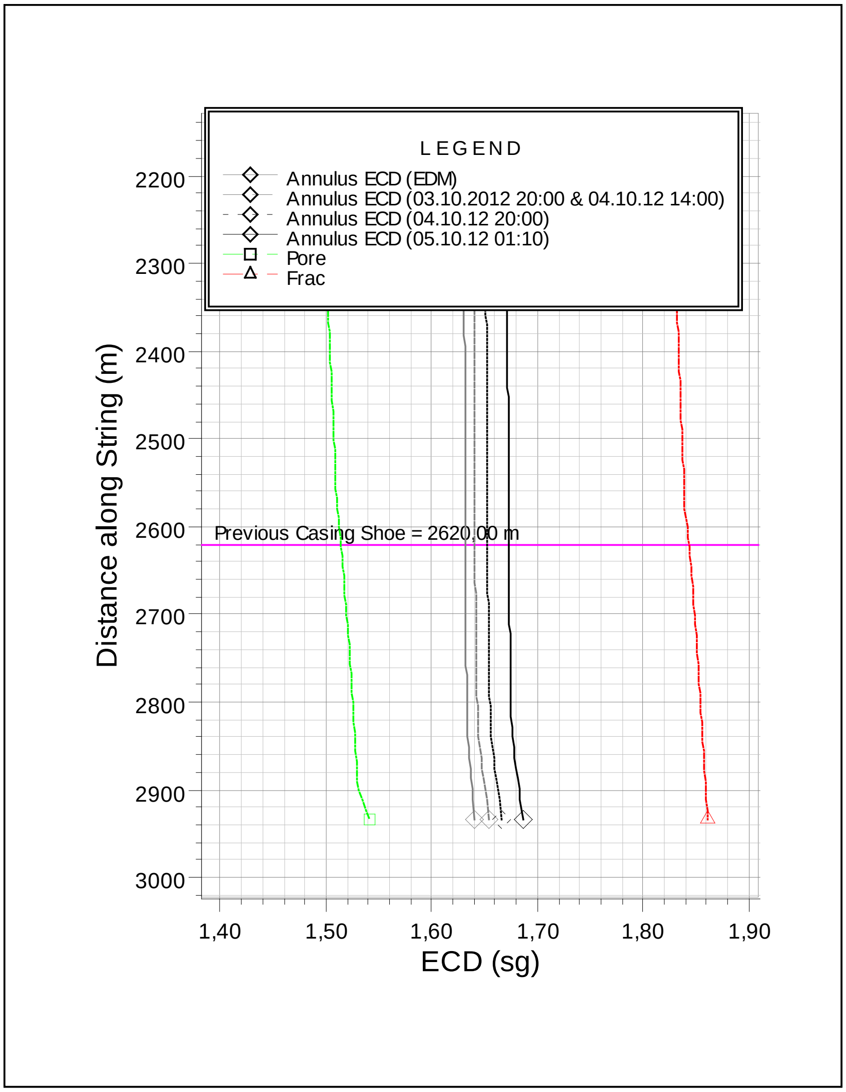


Figure 4.32 The influence of the Drilling fluids from EDM and several actual measurements for C-39 A on ECD.

C-9 AT2

The C-9 AT2 6” x 7” section was selected because of the large density difference between the measurements and the planned from EDM. The results with a flow rate of 1300 l/min are shown in Figure 4.33.

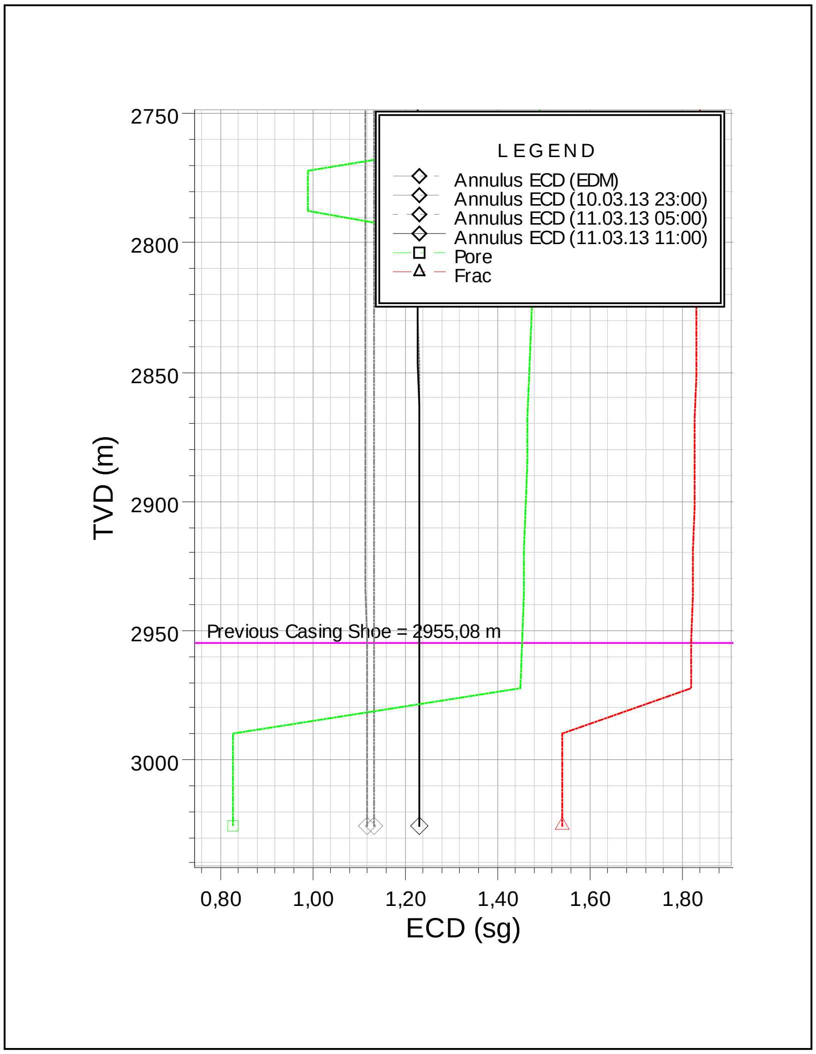


Figure 4.33 The influence of the Drilling fluids from EDM and several actual measurements for C-39 A on ECD.

Chapter 5

DISCUSSION

New work processes related to the implementation of an automated drilling system can be divided into a short time and a long time perspective. In a long time perspective the goal would be to automatically gather and enter configuration data into the automated drilling system with a decent validation system. During the first implementation phase of the automated drilling system the data has to be handled by humans due to lack of technology. This chapter mainly discusses the options for the short term perspective of automated drilling, which means during the early implementation on Statfjord. The discussion is based on a combination of the analysis in Chapter 4 and conversations with Statoil employees. A brief discussion on the possibilities of how to maintain the work processes in a long time frame is given in Section 5.3.

5.1 Quality of planning and design data available today

Requirements of sensor quality related to real-time data are discussed in other reports (Cayeux et al., 2010, 2013). It is a requirement that critical sensors are reliable, and redundancy should be implemented to such sensors, so that reliability can be guaranteed.

The same applies to configuration data, although this type of data normally requires manual management. Manual data management introduces the potential of human error. The drilling fluid density is one of the important input parameters in the calculation of wellbore pressure. A small error in this value can have a serious effect when drilling within a narrow pressure window, and erroneous input values result in wrong calculated limits which will not prevent the driller either from fracturing the well or taking a kick.

From the evaluation of available planning data prior to a drilling operation (Section 4.3) it is apparent that the quality of the planning data compared with the actual drilling data becomes increasingly accurate as time approaches start of the activity. The information in the Activity Program is often clearly inaccurate and will then be inadequate as input to automated drilling.

The reliability of Drilltronics during drilling is dependent on the applied configuration data. The process models benefits from higher update frequencies and better accuracies, but some of the input parameters have a higher importance than others, and thus it is required that some well parameters are updated more often than others.

A discussion of the data availability and the quality of data at different planning stages and during drilling of some of the configuration data parameters follows.

5.1.1 Rig data

Rig data such as the drawworks, the mud pumps and other drilling machinery can all be entered before the drilling operation is started. Today this information is to a large extent held by the product vendors, and must be managed manually from product sheets.

Some pump properties including the stroke volume and pump efficiency may however be changed during the drilling operation due to liner changes (recall Section 2.5.2). Current stroke volumes and pump efficiencies are maintained in the drilling control system, and are consequently imported directly into Drilltronics without the need of additional human intervention.

5.1.2 Wellbore architecture

The wellbore architecture or casing design affects the wellbore calculations, because the diameter and friction factor of a part of a well is changed with variations in casing design. Changes in the plans or unexpected problems may lead to changes in casing design. The first can often be related to the early planning stage, while unexpected problems occur during the casing run. In both cases the BHA is not yet run into the hole and there is much time to make changes in configuration data.

Early planning stage

The findings in Section 4.4.2 indicate that the casing design from the Drilling Program is usually but not always accurate. The planned casing design should therefore be entered into the configuration data editor for later review.

Late planning stage

The Drilling DOPs are normally finalized after the casing is run, which means that the actual wellbore architecture is already accounted for in advance of the new drilling run. The casing design data can consequently be updated right after the casing or liner string is correctly hung off, and there is plenty of time while the cement job is done to update the configuration data.

During drilling

If the section is drilled deeper or shorter than planned, this will only affect the next section of the well, and there should thus be no change in wellbore architecture during drilling.

5.1.3 Wellbore trajectory

One of the goals during drilling is to maintain the wellbore trajectory close to the planned trajectory. Three wells at Statfjord were chosen for evaluation, and the results presented in Section 4.4.1 showed that both trajectories from the Drilling Program and from EDM were slightly different from the actual trajectory. The planned trajectory is used by Drilltronics only when an MWD survey is unavailable. The current updates of the actual MWD is therefore of higher importance than entering a very accurate planned trajectory.

It is important that the corrected directional drilling data is updated frequently in Compass. In other situations the differences in torque and drag values may be significantly higher than the ones shown in Section 4.5.1. Torque and drag is largely influenced by small irregularities in the wellbore trajectory known as wellbore tortuosity, so even though the planned and actual trajectories look similar overall, tortuosity may result in different torque and drag values.

Early planning stage

A planned trajectory is worked with in a long time span before the drilling operation is started. This trajectory could be entered into the configuration editor of the automated drilling system before the operation is begun. But it is then important to know which revision of the trajectory is entered, so that the latest revision is active when the operation is begun.

Late planning stage

In the days before the drilling operation is started the selected revision of the planned trajectory is supposed to be set as principal plan in compass. For the two of the three analyzed wells, C-39 A and C- 13 A, the newest planned trajectory revision in EDM is dated 3 days before the drilling start. For

C-9 AT2 the latest revision is dated 9 days before. The latest revision of C-9 AT2 is however not used, as the principal plan is an older revision. It would therefore be necessary to update the trajectory in the configuration editor at least within 2 days before the drilling start. For C-39 A the changes from the Drilling Program are significant since the casing window was later planned to be drilled 180 meters deeper in the well than previously planned.

During drilling

The actual trajectory is never equal to the planned trajectory, and may lead to different torque and drag calculation results due to wellbore tortuosity. The current trajectory must therefore be updated in the configuration editor during drilling. MWD data can be used as a continuous signal in the automated drilling system, although raw MWD survey measurements are not always accurate and need correction.

> According to Statoil's survey guidelines, MWD raw data shall be corrected for:
>
> - Grid correction
> - Declination correction according to BGGM/IFR[1] referencing
> - Sag of drill string/BHA
>
> General guidelines are made for making estimations of uncertainties in MWD surveys (Torkildsen, Håvardstein, Weston, & Ekseth, 2008; Williamson, 2000). The MWD engineer is responsible for applying these corrections and forwarding the corrected data to the Directional Driller. The Directional Driller is responsible for reporting corrected data into Statoil Directional Survey Database "Compass" during drilling. It is vital that the surveys entered into compass are correct, but then especially because of future wells drilled nearby. The correction and error models are not valid if human mistakes or imperfection in sensor readings can be present.

It would therefore be preferred to use corrected data from EDM Compass as current trajectory in the automated drilling system. This is currently not done automatically, so it is necessary to manually update the current trajectory. Since it in some cases can be drilled close to 1000 m in 24 hours it would be advantageous to have frequent updates. A survey shot is normally taken every 30 m during drilling. The results from the simulations presented in Section 4.5.1 indicates that the current trajectory needs to be kept regularly updated to maintain the deviations in torque and drag modeling at a low level. This particularly applies to long wellbore sections with build/drop or turns.

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[1] BGGM (BGS Global Geomagnetic Model): A mathematical model of the Earth's magnetic field in its undisturbed state. IFR (In-Field Referencing).

5.1.4 Drill string

Details about the elements of the drill string are important input to the hydraulic and mechanical wellbore models. Equally important is it to know which components have been run in hole. It has already been shown (in Section 4.4.3) that the actual BHA components run may differ significantly from the planned BHA tally. The correct description of the BHA is important both for torque and drag and hydraulic calculations at larger depths.

Early planning stage

When the planned BHAs and the actual BHAs are compared, there are few significant differences present. The well sections that had largest changes were the C-9 AT2 17 ½” and the C-13 A 8 ½” x 9 ½” section, and the latter well section was selected for analysis. The results of the hydraulics and torque and drag analysis presented in Section 4.5.2 show that the hydraulic simulation had a maximum disagreement of 0.006 sg. The torque simulation showed a 400 Nm disagreement, and the maximum hook load difference was 2 tons.

The results from the Wellplan simulations in Section 4.5.2 thus indicate that the changes from planned to actual BHA tallies involve only minor influence on hydraulic and mechanical simulations. An automated drilling system does however take advantage of the best possible description to avoid unnecessary calibration. The BHA description could therefore be entered into the automated drilling model in advance, but because of the significant changes which are present in some of the wellbore sections, the BHA description should be quality checked and updated later.

Late planning stage

In all the evaluated well sections, the BHA from the DOP is very close to the actual BHA. The exceptions are C-39 A 8 ½” where an insert bit is wrongly entered in the DOP, and the C-9 A 12,25”x14” section where the PowerDrive X6 was used instead of the planned PowerDrive X5. This indicates that last minute changes do occur, and such changes must be expected. The change of Rotary Steerable Systems or motor devices may have an impact especially on the hydraulic calculations because of potentially different pressure loss coefficients.

During drilling

A final BHA tally is made just before the BHA is tripped into the hole. To have the updated BHA description in the configuration editor, the final tally should be used. Dependent on the depth of the hole, it can take several hours before the bit is at the bottom and ready to continue drilling. Therefore there is plenty of time to update the configuration data after the BHA is assembled. However, because of the importance of precise calibration of BHA and drill pipe in Drilltronics, the weight calibration of the BHA should be performed as early as possible, and at least when the entire drill string is still in the vertical section. Consequently the drill string description should be updated before starting running HWDP. The time window to update the configuration data is therefore narrowed.

There are several challenges with the complexity of BHA configuration data. It was mentioned in a summary from the Automated Drilling Pilot that it was difficult to obtain specific parameters from special BHA components, such as pressure loss coefficients from MWD tools, and MWD activation flow rate ranges (Cayeux, Daireaux, et al., 2009). Some components are activated by ball drop or applied pressure or torque, and require updates of configuration data during the BHA run when the tool becomes activated. Under-reamers and circulation subs are examples of components that are often activated by ball drops. The status of the tools may have large influence on mechanical and hydraulic calculations, and since there is no signal telling the status of the component, the system can only rely on pressure spikes or any other indication that suggests status changes. A suggestion by the author for improvement of the configuration data editor is to allow entering properties for every possible status of the BHA components, so the new parameters are already ready when the new function in the BHA is activated. Such a system could be extended to a database where the required properties of all BHA components available on the drilling rig could be given by the service companies delivering the products. When the responsible person for drill string configuration data enters the BHA components, the parameters may be automatically extracted from the database or file.

5.1.5 Drilling fluid

An automated drilling system requires precise input data of drilling fluid properties. Density, temperature and rheology should either be known for all mud pits, with the system knowing which pit is active, or the properties must be measured directly on the stand pipe with special equipment.

Drilling fluids have a major impact on annulus ECD. The results from the analysis of the C-9 AT2 17 ½” section indicated that the frequency of drilling fluid samples in some cases should be increased from the current 4 times a day when the mud weight is being increased during drilling. This is however only relevant if the ECD is close to the prognosis of pore pressure, collapse pressure or fracture pressure.

Early planning stage

The drilling fluid is given with very approximate properties in the Drilling Program. An example of available drilling fluid information from the Drilling Program is printed in Appendix B.3. In the comparisons of mud weights for various well sections in Appendix C.3, only the C-9 AT2 well is accurate regarding the mud weight in the drilling program. For this well the mud weight is actually precisely given in the Drilling Program for all four well sections. Since the mud weights for the well sections in C-39 A are slightly disagreeing with the measured mud weights, and the values given for C-13 A are significantly deviating, the mud weight values from the Drilling Program tend to be too uncertain for utilization in model based process control. Rheological data are almost non-existent in the Drilling Program.

During the early planning stage, mud properties are entered in Wellplan for hydraulics and torque and drag simulations. The mud weight is selected by the geologist and drilling engineer, and is seen in several of the analyzed occasions (Section 4.4.4) to differ from the mud weights given in the Drilling Program. In 2 out of 8 cases the rheology in Wellplan is completely wrong, and in 3 out of 8 cases the density in Wellplan is at least 0.02 sg (with a maximum error of 0.1 sg) off the initial density measurement. The hydraulics analyses presented in Section 4.5.3 show that the rheological deviations in the C-39 A 8 ½" section cause a simulated ECD difference of 0.05 sg. The large disagreement in mud weights in C-9 AT2 6" x 7" section causes a simulated ECD difference of 0.10 sg. The results indicate that rheology has an important influence on the annular pressure loss, and consequently affects the ECD. This is also in agreement with hydraulics theory from Section 2.3.2, where rheological data is an important part of the pressure loss calculations.

Late planning stage

The DOPs contain little details about the drilling fluid. The type and density of the drilling fluid is normally given. Adequate mud properties is received not before the mud is mixed on the platform and measured by the mud engineer.

During drilling

The only adequate estimates of drilling fluid properties are obtained from direct measurements of the drilling fluid. In all the analyzed well sections except for C-9 AT2 6" x 7" the last reported mud properties the day before a new section is commenced seems to be adequate as initial input in the automated drilling configuration data editor. This is because the mud is often weighted up or displaced before the previous casing shoe is drilled out. The one exception is enough to claim that a higher reporting rate than once a day is needed. Sometimes the mud is weighted up when the casing shoe is being drilled out. If an automated drilling system is supposed to be used in this situation it is necessary to have work procedures with frequent mud property updates.

Another considerable challenge is the weighting up of the mud weight during the C-9 AT2 17 ½" section. Figure 4.14 shows the complete sampling sequence with a sampling rate up to four times a day. Five times during the section is drilled the mud is weighted up with at least 0.3 sg between two drilling fluid measurements. In one occurrence the difference is 0.5 sg. This is a considerable issue as the mud weight strongly affects the hydraulics wellbore models. The only measure that can cure this issue is to increase the sampling rate of fluid measurements when large changes in mud properties are expected.

5.2 Adaption of work processes to automated drilling

The introduction of an automated drilling system carries a requirement of changes in the current work processes. Among the main challenges being introduced are the responsibilities related to input of configuration data into the automated drilling system, and thorough quality control of these data. The responsibility that comes with updating the configuration data is significant, given the large consequences if the automated drilling system acts on wrong premises. Therefore, the responsible personnel for the configuration data must be aware of the risks and consequences when they enter data. It is also clear that a validation process of the entered data is implemented to reduce the risk of potential human errors.

The job related to the responsibility of entering the system configuration data can now be clarified, based on the discussion about the available configuration data in the previous section. The major part of configuration data does not normally require updates during drilling of a well section. It is mainly after a casing is set and cemented that configuration data must be updated. The exceptions are trajectory surveys and drilling fluid measurements, which must be updated more frequently, and BHA description in case of new BHA runs during a section.

The responsibility of updating and validating configuration data requires training. The more people that is involved in the process, the more comprehensive the training will be. In order to suggest new work processes, the relevant personnel on the drilling rig and in onshore offices are first presented briefly.

5.2.1 Available offshore and onshore personnel

The responsibility of entering configuration data into the Drilltronics system can be carried either by Statoil personnel, service company personnel, or drilling contractor personnel.

The minimum number of Statoil personnel on a Statfjord platform when a drilling operation is carried through is a Drilling Supervisor Day and a Drilling Supervisor Night. In addition there is generally a Statoil Drilling Engineer working day shift offshore. The offshore engineer position is however not always manned. In addition to the offshore staff there are several drilling engineers working onshore on normal working hours. There is also an onshore drilling superintendent and a drilling engineer available 24/7.

Service company personnel are often strongly specialized in a specific area and may be qualified for the responsibility of updating data from their special field only. Service personnel often have a very good knowledge of the required configuration data and are often responsible for the data in general. The added responsibility of updating the automated drilling system data will require thorough training and may give contractual issues.

The drilling contractor personnel comprise the persons who are performing the drilling operation, including the driller, assistant driller, derrickman and roughnecks. Out of these, the driller and the assistant driller are the persons who may be relevant for working with configuration data, although more for validation than for entering.

5.2.2 Suggested system configuration data management in the planning phase

Because several categories of planning data of the three analyzed wells were seen to be close to the actual data but not close enough for optimal automation, it is suggested that planning data is entered in the system by onshore engineers during the planning phase. A new update could be performed the last day before the drilling operation either by onshore or offshore engineers.

In the planning stage it would be advantageous to have an overview of when the configuration data last was updated. This could best be done in the Drilltronics configuration editor, or by simply having an Excel spreadsheet that is made only to have an easily distributed document that explains which revision of planning data is currently entered into the configuration data editor. An example of such a solution is shown in Figure 5.1. This system is however not foolproof because it is still possible to edit the system configuration data without updating the Excel spreadsheet, so the procedures must be well established for this to work.

Although most planning and design data normally will function only as basis for actual data, some configuration data is seen to seldom change from the planning phase to the operation phase. Rig machinery data normally has the same values during a long time frame.

		Status	Last updated	User
51	**Geo-Pressure and Geo- Thermal Properties**			
52	**Geology**			
53	Pore pressure	Planning data - Confirmed	11.04.2013 11:58	abcd
54	Collapse pressure	Planning data - Confirmed	11.04.2013 11:58	abcd
55	Fracture pressure	Planning data - Confirmed	11.04.2013 11:59	abcd
56	Min horizontal stress	Planning data - Confirmed	11.04.2013 12:00	abcd
57	Prognosed geothermal properties	Planning data - Confirmed	11.04.2013 12:00	abcd
58	Prognosed formation tops	Planning data - Confirmed	11.04.2013 12:02	abcd
59	Observed formation tops	Actual data - Confirmed	13.04.2013 19:49	efg
60	**Drill string**			
61	Drill string details	Actual data - Confirmed	14.04.2013 09:03	efg
62	**Drilling Fluid**			
63	Density	Actual data - Unconfirmed	14.04.2013 14:37	xyz
64	Rheology	Actual data - Unconfirmed	14.04.2013 14:44	xyz
65	Temperature			
66	Other parameters			
67				

Planning data - Unconfirmed
Planning data - Confirmed
Actual data - Unconfirmed
Actual data - Confirmed

Figure 5.1 A simple suggestion to a system configuration data status sheet

5.2.3 Suggested system configuration data management during drilling

A general rule for all the configuration data is that the planned data can be used as initial input to the automated drilling system, but because of late configuration data updates and varied quality of planning and design data, it is for many of the data categories suggested to enter new and updated information in the configuration editor only a short time before drilling of a new section is started, or even during drilling for some situations. This was seen to apply to the BHA, the casing design, FIT/LOTs, the drilling fluid and the wellbore trajectory. The results indicate that it is advantageous to have the person or persons responsible for the late updated configuration data of the automated drilling system located offshore. The list of required system configuration data is very long (See Appendix A for the list), and the resulting responsibility of updating the configuration data is so large that it would probably occupy a 24/7 role offshore if one person do the job. A better solution would probably be to let several persons have responsibility for parts of the configuration data.

The persons responsible for entering configuration data to the automated drilling system are considered to be one or several of the following:

1. Drilling engineer day and drilling supervisor night
2. Mud logger (Geoservices)
3. Assistant driller
4. Configuration data providers (Directional Driller, Mud Engineer and Drilling Engineer)
5. Provider of the automated drilling system (Onshore or offshore)

1. *Drilling Engineer Day and Drilling Supervisor Night*

The Drilling Supervisor Night and the Drilling Supervisor Day are both responsible for supervising the drilling operation, but they have slightly different tasks during the work shift. While the Day Supervisor is required in many meetings during his shift, there are seldom meetings going on during the night. The Night Supervisor is responsible for the daily reporting of the ongoing activity, and has in general more time for other duties. Therefore the combination of Drilling Supervisor Night and a day drilling engineer is an option as responsible persons for updating configuration data. The advantage of using the drilling engineer is that he has a relatively good overview of configuration data in general.

One drawback with this suggestion is that the offshore drilling engineer position is not always manned. And if the drilling engineer is away another person must take over the role, and different work procedures are needed. Another drawback is that the drilling supervisor is already responsible for confirmation of large parts of drilling data, and it would be more suitable for the supervisor to have the role of validating data.

2. *Mud logger*

The mud logger keeps track of the well status with continuous analysis of surface data to detect borehole problems or kicks. Since the mud logger already uses all available data to support efficient drilling operations it could be an option to give him additional responsibilities.

The additional responsibilities for the mud logging service provider may however lead to contractual issues. With this responsibility the role of the mud logger would also change significantly.

3. *Assistant driller*

The assistant driller is responsible for assisting the driller, and his attention is drawn to the drill floor and drilling operation. Since the assistant driller is working on the drill floor he is usually located a distance from the persons who has the best knowledge of required configuration data (the directional driller, mud engineer and drilling engineer). This may be inconvenient for the assistant driller if he is responsible for system configuration data updates.

4. *Configuration data providers*

During the drilling operation, the configuration data in terms of directional survey, BHA, casing tally and drilling fluid are managed by a few essential persons on the drilling rig. The directional driller is responsible for entering corrected surveys into Compass. The directional driller is also responsible for keeping track of the As Run BHA tally in cooperation with the assistant driller, and he is one of the persons with the best knowledge of the BHA components. The mud engineer keeps track of the drilling fluid, and reports to the Drilling Supervisor Night. The drilling engineer is responsible for the casing tally and makes an As Run tally after the casing run. Because these persons already are responsible for the necessary data, and report this data to other databases, it is an option to let them have an additional responsibility of adding updated data to the automated drilling system's configuration data editor. This additional task will not be time consuming because each person is responsible for a small part of the configuration data only.

This will in fact reduce the complexity of the work procedures compared with the previously discussed options, although training of a higher number of persons in the automated drilling system is required.

5. *Provider of the automated drilling system*

The personnel representing the supplier of the automated drilling system (which is Sekal AS in the case of Drilltronics) have a high knowledge of the system and knows very well the criticality of the data that is entered in the system. In the case of implementation of Drilltronics on Statfjord, Sekal provides monitoring services for the drilling operation. Sekal personnel will monitor the drilling operation 24/7 from an office located onshore.

Since Sekal already has people with good knowledge of Drilltronics working day and night, it would be an option to give them the responsibility to update the configuration data. The main drawback is that the Sekal personnel are located onshore, and this solution may be prone to communication challenges. This situation may be bothersome for data that must be updated regularly, like drilling fluid properties and directional data. Another drawback is the consequences if the network connection between the offshore and the onshore location is suddenly disconnected. If the Sekal personnel were located offshore these drawbacks would be non-existent, although the expense of having expertise on every rig would be very high.

Data management with a configuration data responsible

The solution with one person in charge of the configuration data is illustrated in Figure 5.2. In this illustration it is assumed that the person responsible for configuration data gathers the required data from the directional driller, the mud engineer, and the drilling engineer. But in reality there would also be more sources for example those associated with rig data.

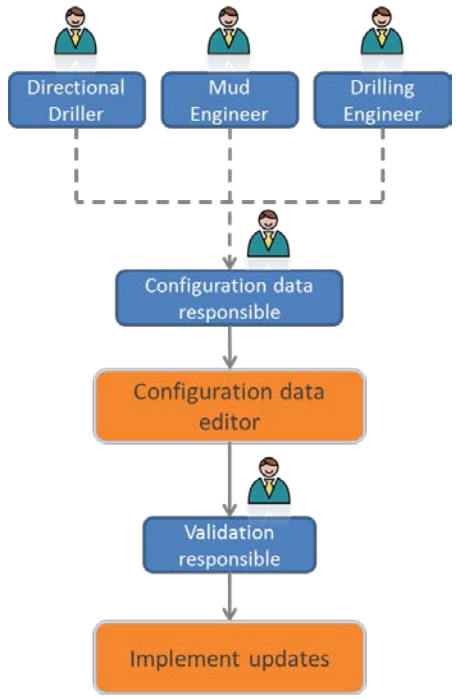

Figure 5.2 Work procedure for configuration data updates with a designated configuration data responsible

Data management with several persons responsible for parts of the configuration data

If the responsibility of entering configuration data in the drilling phase is distributed among several persons the configuration data responsible can actually be removed, as illustrated in Figure 5.3. Because the directional driller has a high knowledge about the BHA components and has easy access to the properties of the components, it will be only a minor additional task to enter the actual drill string description into the configuration data editor. The directional driller is an important source for the BHA data regardless of who does the update, so for high efficiency and accuracy, the directional driller may be responsible for the update. Similarly the person who is the most appropriate to update the drilling fluid description is the mud engineer. The mud engineer receives the measured drilling fluids values whenever a new measurement is taken, as opposed to everybody else who has to wait for the daily drilling report after midnight, or personally ask the mud engineer. The drilling engineer is involved in the casing string run and formation tests, and may quickly enter the required actual casing data and LOT/FIT data into the configuration editor. The final configuration data that has been earlier discussed are rig data and geo-pressure data. Due to seldom changes in these properties it is in general not necessary to update these types of configuration data during the drilling process, and they are therefore not included in this discussion.

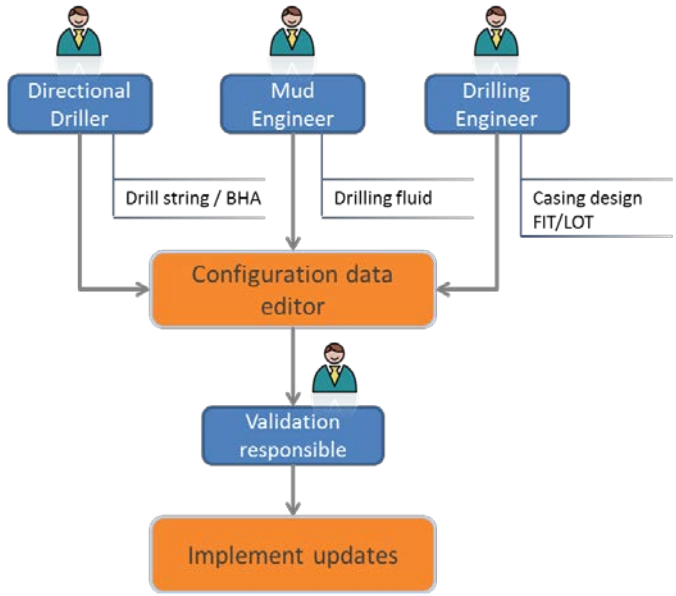

Figure 5.3 Work procedure for configuration data updates without a designated person responsible for configuration data

5.2.4 Validation of system configuration data

Because of the large consequences related to the responsibility of configuration data updates, the configuration data should be validated before new data is implemented to avoid typing errors or other human errors that may cause problems to the drilling process. In the meantime the Cyberbase drilling workstation should alert the driller that some configuration data is not validated. Drilltronics will continue to run, as described in Section 3.2.2, but will not allow activation of new functions of the system before validation process has been completed. The required level of precision in the validation process can be discussed. Configuration data can be controlled for typing errors by a comparison of the same data sources as the original input. Potential errors in the data sources, caused by either inaccurate measurements or by typing errors, will however still remain, and are much more difficult to filter out.

Validation could be performed either by different persons with different responsibilities, or by one person who validates everything. The last option would require a person with broad knowledge within drilling and the Drilltronics system. There are three clear options of people to validate the data.

1. The drilling supervisor and drilling engineer
2. The driller and assistant driller
3. The provider of the automated drilling system

The first option suggests that validation could be performed by either the drilling supervisor or an offshore company drilling engineer. The flow chart in Figure 5.4 gives a suggestion by the author of how validation during a drilling operation can be performed.

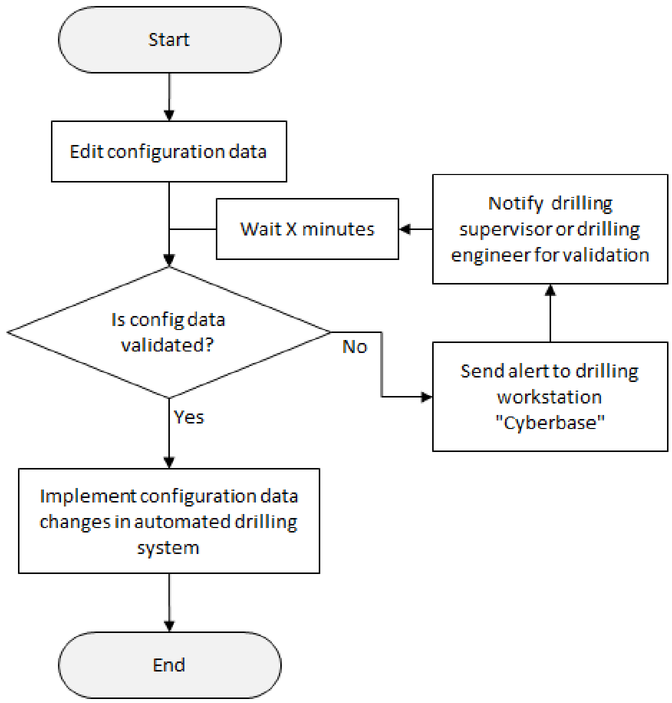

Figure 5.4 Suggested flow chart for validation of system configuration data #1

The fact that the driller is completely excluded from the configuration data may be a drawback with the previous suggestion. Since the driller has the main responsibility for the well, it could be an advantage that he is included in the process. When the driller is responsible for the validation of the data he gets simultaneously an awareness of the current configuration data which sets the limits for the drilling operation. In addition he can decide exactly when the new configuration data is implemented. Figure 5.5 illustrates the process of updating configuration data with the driller as responsible for the validation of the data. In this case the driller would need a screen on his console for the configuration data. On the other hand, the driller is located remotely from the directional driller and mud engineer and other personnel that can provide the necessary material for validation. It can also be discussed if the driller really needs to take part in configuration data updates. Instead the driller may have a screen visually ilustrating the current configuration data entered in the system.

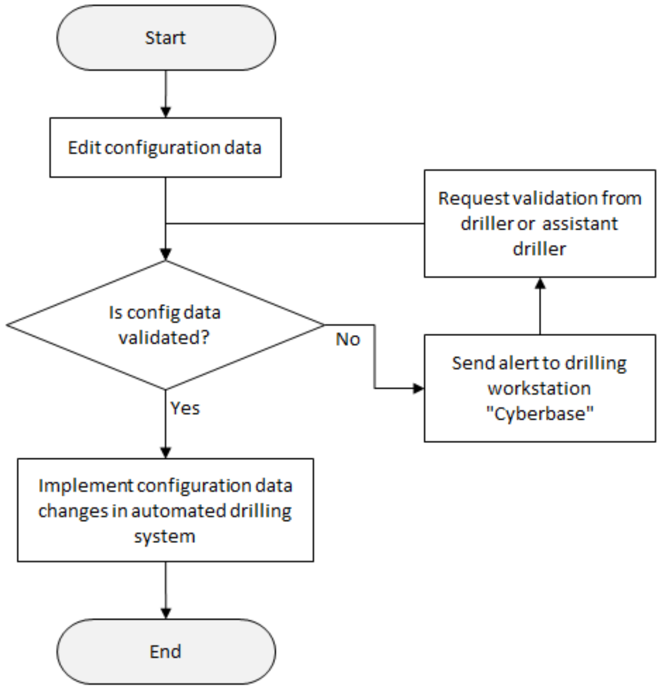

Figure 5.5 Flow chart for validation of system configuration data #2

The configuration data editor is not made for validation of the entered data. Instead a separate program is made for this purpose where all data has to be validated after any configuration data update.

Another solution suggested by the author is to implement the status of the configuration data in the configuration editor as illustrated in Figure 5.6. This will allow any person who has access to the editor to see which data is currently used by the process models, and which data is waiting for validation by the responsible person.

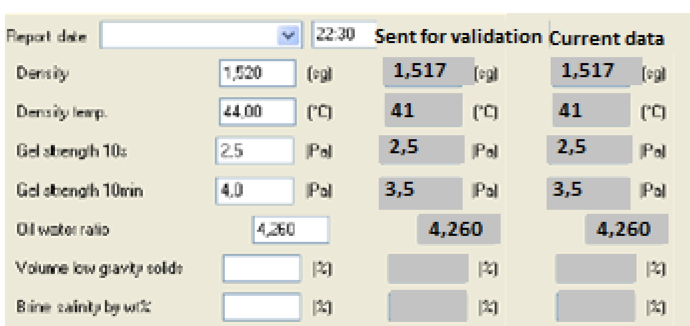

Figure 5.6 A new function of the configuration data editor could be to include the status of the entered data

5.3 Future solutions to configuration data management

Currently the configuration data must be gathered and entered manually into the automated drilling system. New solutions can make it possible to automate this process. Two different solutions are presented in this Section. The first one is an established system which is supposed to export the required configuration data directly from the different planning and design data sources. The second one is a different solution suggested by the author, where new technologies are used in a real-time tracking system of the current actual drilling and well configuration data.

5.3.1 Automatic gathering of planning data

A system that will automatically withdraw configuration data from the original data sources is under development. The system is called Live Well Configuration Manager (LWCM) and is developed by Statoil's research center. LWCM will gather information from the various System Configuration Data Sources, as illustrated in Figure 5.7, and make all data easily available for other computer systems such as Drilltronics. There are large challenges with work processes related to that system as well, one being the challenge considering validation of entered data after updates to any of the System Configuration Data Sources. An option is to continue using the suggested validation process as illustrated in Figure 5.5 where the driller remains the complete control of which data is used in the well. The work procedures for entering data into EDM, DBR and the other relevant data sources must be significantly improved for a system like this to function properly. Today there are too many erroneous values in many of the data systems caused by human errors.

The number of data sources is another challenge, because now the data is relatively scattered. The analysis of configuration data from various sources in Section 4.5 indicated that only few types of configuration data from the various planning and design data sources actually contained accurate information. The most valuable data for automated drilling systems were found in DBR, which contains daily reported actual data from the current activity. The planning data from EDM is in general only good enough for preparations, and needs to be replaced by actual data from DBR when the drilling operation is started. There is one important exception; EDM is currently the main database for trajectory and survey data in Statoil.

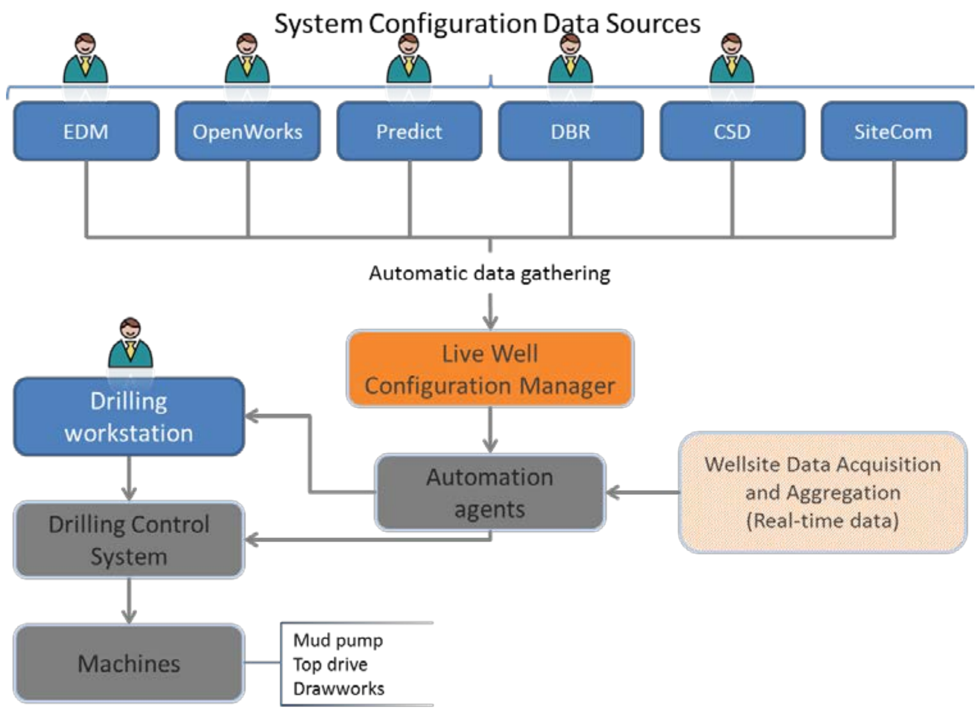

Figure 5.7 Data management of System Configuration Data with Live Well Configuration Manager

5.3.2 Real-time tracking of actual configuration data

A different approach suggested by the author is to have live tracking of the configuration data, which will almost completely exclude the requirement of manually entering configuration data. This will also decrease the offshore workload and reduce the risk of human error. Several changes must be made to the drilling equipment in use today to obtain a complete automatic tracking of configuration data. Suggestions for use of available technology and technology under development to make a real-time tracking system are given in the following.

Casing string

An electronic casing tally can be made by using a tag and scan system. A tag printed on each casing joint can refer to a database with information about the chosen casing joint. When casing is run, a scanner in the rotary table can automatically make the casing tally and provide the full length of the casing string. Challenges to a system like this may appear when a side-track through a casing window is planned. Manual changes will then have to be done.

Wellbore trajectory

Real-time surveys already exist, but the accuracy of such systems is currently not good enough. Corrections must be applied to MWD surveys to account for magnetic declination and grid correction (Section 5.1.3). The solution would be either to utilize better surveying instruments, or to apply automatic corrections.

Drill string

The optimal way to make an automatic BHA tally is to track the drill string and BHA components while running in hole. In such a system every component needs a tag that can be associated to the one component, containing all necessary properties. The lists of properties should be delivered by the BHA component provider.

A pipe tracking system called Drill Pipe Tracking is already introduced and has been tested on Snorre B and on Statfjord C on several occasions ("ISWC," n.d.; Larsen et al., 2010). All drill string component are equipped with RFID[2] tags. An RFID antenna positioned in the Rotary Table register all elements which go into the wellbore. So far the system has been used to estimate the fatigue of every element of the drill string. By having a database with dimension data from all drill pipe and BHA components available on the rig, such a pipe tracking system could be used to make a real-time BHA and drill string tally that can be used in automated drilling.

Drilling fluid

Automatic measurement of drilling fluid properties has been researched in recent years, and several methods have been introduced, some for measurements on the stand pipe, and some for measurements between the shale shaker and pits (Carlsen, Nygaard, & Time, 2012; Saasen et al., 2009). Only the standpipe measurement will allow one to measure the fluid that is pumped into the wellbore.

Coriolis flow meters and real time rheology sensors for drilling fluids are under development and will make an important addition to the automated drilling system if successful. A different method is the Instrumented Stand Pipe, which involves continuous pressure monitoring of the flow path between differential pressure transducers. These pressure measurements can be used to calculate fluid density and rheological parameters. Tests have indicated that the instrumented standpipe can be used for measuring fluid rheology parameters, but the results were not conclusive (Carlsen et al., 2012).

[2] RFID (Radio-Frequency Identification) is the use of an object (typically referred to as an RFID tag) applied to or incorporated into a product, animal, or person for the purpose of identification and tracking using radio waves (Larsen et al., 2010).

Chapter 6

CONCLUSION

This thesis has analyzed existing planning and design data for three wells at Statfjord C in order to evaluate the potential for utilization of this type of data as configuration data in the implementation of the automated drilling system Drilltronics on Statfjord. The requirements of new work processes when implementing the system are discussed, in addition to suggestions to new work processes.

- Planning and design data management:
  The current manual planning and design data acquisition process is inefficient. This data is stored in various databases and in different formats. If planning and design data is to be used in model based process control, data must be handled more efficiently.

- Planning and design data quality:
  The data quality of the analyzed planning and design data is seen to have increased accuracy with time. The planning data issued a day before the planned operation is significantly closer to the actual data than earlier planning data.
  Simulations with a wellbore torque and drag and hydraulics simulation software on both planning and design data and actual data indicated that the use of planning and design data in wellbore models generally will give results that differ from the simulations done with actual data. This is especially important for drilling fluid data, which is seen to have the least accurate planning data. The use of other planning and design data sources, such as wellbore architecture, wellbore trajectory and BHA tally is also seen to have a negative influence on wellbore modeling.

- Suggested configuration data sources:
  Because planning and design data
    1. changes in time during the planning phase of the operation
    2. are of inadequate quality
    3. currently exists in numerous databases and data formats

it is suggested that the use of planning and design data as configuration data in model based process control is insufficient compared with the utilization of actual data as configuration data. It is therefore suggested to extend the use of the daily reporting tool of actual drilling data DBR as configuration data source. The analyses indicate that utilization of actual data is feasible but will require new work processes.

- Work processes:
  The importance of good quality configuration data makes clear the requirement of new work processes. Suggestions to new work processes are made. It is suggested that the configuration data management is handled by the offshore personnel, with several persons responsible for different data sets. Because human errors are frequent in current data management, a validation process is required. This is suggested to be done by the drilling supervisor or drilling engineer.

The suggested procedure is developed for the implementation of Drilltronics on Statfjord. The future of drilling automation will take advantage of less interference from human personnel. New technology can be used in the future to automatically gather actual data for use as configuration data while drilling.

FURTHER WORK

This document has proposed new work processes. Further studies should be done to analyze the possibility to implement the suggestions made. This involves determining whether the DBR system can be used as the source database for configuration data, or if a different system must be used.

A thorough survey should be done to determine if the proposed work processes can be implemented. Especially important in this context are the contractual challenges, and the additional time required by the involved personnel to perform the new work tasks.

A study that analyzes the economical outcome of an automated drilling system would also be beneficial.

The automated drilling system can be further developed to reduce the need for human labor. One possible solution is to reduce the requirement of manual management of configuration data. This possibility is shortly discussed in Section 5.3 in this document, but the technologies currently available may not be designed for this purpose.

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Appendix A

LIST OF CONFIGURATION DATA

A.1 RIG AND DRILLING MACHINERY DATA

Configuration data	Data source	Suggested update frequency
Rig		
Rig name	Drilling Program, DBR	Before operation
Default air temperature	Manual	Before operation
Mud density correction	Manual	Before operation
Drawworks		
Travelling equipment weight	Manual	Before operation
Creep speed	Manual	Before operation
Max hoisting velocity	Manual	Before operation
Max hoisting acceleration (speed inc)	Manual	Before operation
Max hoisting acceleration (speed dec)	Manual	Before operation
Min hook position	Manual	Before operation
Max hook position	Manual	Before operation
Pumps		
Flow rate accuracy	Manual	
Min flow rate	Manual	Before operation
Max flow rate	Product Datasheet	Before operation
Max pump pressure	Product Datasheet	Before operation
Stroke volume	Product Datasheet	New section (Liner change)
Pump efficiency	Manual	New section (Liner change)
SPM correction factor	Manual	New section (Liner change)
Rotary/Top drive		
Drive type	Product Datasheet	Before operation
Max rotary speed	Product Datasheet	Before operation
Max torque	Product Datasheet	Before operation

A.2 WELLBORE ARCHITECTURE AND TRAJECTORY

Configuration data	Data source	Suggested update frequency
Riser		
Body OD	Manual	Before operation
Body ID	Manual	Before operation
Length	Manual	Before operation
Blow out preventer (optional)		
Top BOP depth		Before BOP run
Length		Before BOP run
Max pressure rating	DBR	Before BOP run
Max thru OD		Before BOP run
Well architecture	EDM	New section
Casing design	EDM	New section
Planned trajectory		
Measured depth	EDM	Before operation
Inclination	EDM	Before operation
Azimuth	EDM	Before operation
Current trajectory		
Measured depth	EDM, DBR	Every survey point
Inclination	EDM, DBR	Every survey point
Azimuth	EDM, DBR	Every survey point

A.3 GEO-PRESSURE AND GEO-THERMAL PROPERTIES

Configuration data	Data source	Suggested update frequency
Geology		
Pore pressure	Predict	Before operation / As required
Collapse pressure	Predict	Before operation / As required
Fracture pressure	Predict	Before operation / As required
Min horizontal stress	Predict	Before operation / As required
Prognosed geothermal properties	Manual	Before operation
Prognosed formation tops	Manual	Before operation
Observed formation tops	DBR, OpenWorks	Occasionally
FIT/LOT data	DBR	After testing
Thermal properties		
Geo-thermal gradient	EDM	Before operation
Specific heat capacity	Manual	Before operation
Thermal conductivity	Manual	Before operation
Rock density	Manual	Before operation

A.4 DRILL STRING AND DRILLING FLUID PROPERTIES

Configuration data	Data source	Suggested update frequency
Drill string		
Drill pipe details	Manual	New section
BHA details	Manual	New section / As required
Drilling Fluid		
Density	Autofluid / SiteCom	New section / As required
Rheology	Autofluid / SiteCom	New section / As required
Temperature	Autofluid / SiteCom	New section / As required
Other parameters	Manual / DBR	New section / As required

Appendix B

EXAMPLES OF CONFIGURATION DATA FROM THE ACTIVITY PROGRAM

B.1 WELLBORE ARCHITECTURE

An example of drilling fluid information from the drilling program is found in Figure B.1.

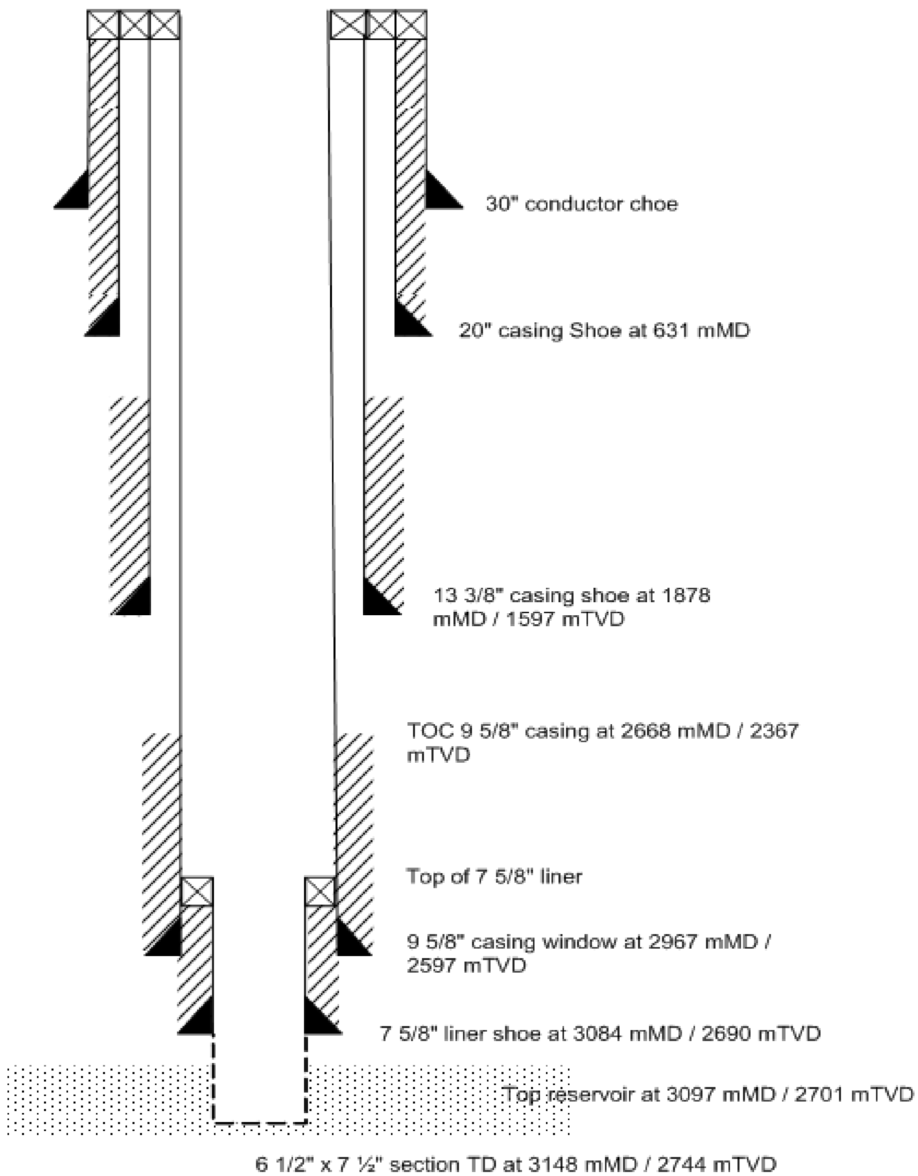

Figure B.1 Example of wellbore architecture information from the drilling program

B.2 DRILL STRING

An example of drilling fluid information from the drilling program is found in Figure B.2.

Schlumberger

Statoil

Field Name	Statfjord	Borehole Name	C-39 A	Hole Size (in)	8,500
Structure Name	Statfjord C	BHA Name	8 1/2" PDC-PD-ARC-MWD-2NMDC-5HWDP	Depth In (m)	0,00
Well Name	33/09-C-39			Depth Out (m)	0,00

	Desc.	Manu.	Serial Number	OD (in) / ID (in)	Max OD (in)	Bot Size (in) / Top Size (in)	Bot Type / Top Type	Bot Gender / Top Gender	FN OD (in) / FN Length (m)	Length (m)	Cum. Length (m)	Cum. Weight (t)
				5,750					0,000			
1	8 1/2 " PDC Bit			2,250	8,500	4,500	REG	Pin	0,00	0,30	0,30	0,1
				6,750		4,500	REG	Box	0,000			
2	PD 675 Xtra AA 8 1/2" Slick CC	Schlumberger		4,200	8,100	4,500	NC50 (4 1/2 IF)	Box	0,00	4,15	4,46	0,7
				6,750		4,500	NC50 (4 1/2 IF)	Pin	0,000			
3	SRX Stab 8 3/8"	Schlumberger		3,250	8,385	5,500	FH	Box	0,00	1,52	5,98	0,9
				5,220		5,500	FH	Pin	0,000			
4	PLF6C-AA Flex Collar	Schlumberger		4,000	7,000	5,500	FH	Box	0,00	2,96	8,94	1,1
				6,750		5,500	FH	Pin	0,000			
5	ARC-6	Schlumberger		2,810	7,500	5,500	FH	Box	0,00	5,49	14,42	2,0
				6,750		5,500	FH	Pin	0,000			
6	PowerPulse 675	Schlumberger		5,109	6,890	4,500	NC50 (4 1/2 IF)	Box	0,00	7,53	21,95	2,9
				6,500		4,500	NC50 (4 1/2 IF)	Pin	0,000			
7	2 x 6 1/2" NMDC (2 joints)	schlumberger		2,250	6,500	4,500	NC50 (4 1/2 IF)	Box	0,00	19,00	40,95	5,7
				5,000		4,500	NC50 (4 1/2 IF)	Pin	0,000			
8	5 x 5" HWDP (5 joints)	Rig		3,000	6,500	4,500	NC50 (4 1/2 IF)	Box	0,00	45,00	85,95	9,1
				6,500		4,500	NC50 (4 1/2 IF)	Pin	0,000			
9	Hydra-Jar	HE		2,750	6,500	4,500	NC50 (4 1/2 IF)	Box	0,00	9,50	95,45	9,9
				5,000		4,500	NC50 (4 1/2 IF)	Pin	0,000			
10	7 x 5" HWDP (6 joints)	Rig		3,000	6,500	4,500	NC50 (4 1/2 IF)	Box	0,00	63,00	158,45	14,6
				4,928		4,500	NC50 (4 1/2 IF)	Pin	0,000			
11	5" 19.50 DPS, 10% Wear	Rig		4,276	6,625	4,500	NC50 (4 1/2 IF)	Box	0,00	10,00	168,45	15,0

Total Length (m)	168,45
Total Weight in Air (t)	15,0
Total Buoyant Weight (t)	12,1
Buoyant Weight Below Jar (t)	7,5
Weight in Air Below Jar (t)	9,1

BHA Comments

Mud Properties	
Mud Weight (g/cm3)	1,50
Mud Type	
PV (cP)	
YP (lbf/100ft2)	

Sensor Offset from Bit (m)	
Gamma Ray	2,30
D+I	2,57
APWD	10,33
ARC Resistivity	11,05
ARC Gamma Ray	11,12
Gamma Ray	17,44
D+I	18,09

Stabilizer Summary		
Blade Mid-Pt to Bit (m)	Blade OD (in)	Blade Length (m)
4,913	8,385	0,610

Bend Summary	
Bend Angle (deg)	Bend to Bit (m)

BHA Nozzle Summary			
Bit Nozzle		Reamer Nozzle	
Count	ID (1/32 in)	Count	ID (1/32 in)
3	13,000		
3	12,000		
		TFA (in2)	
		PD Flow Restrictor	
		(1/32 in)	0,000
		Rotor By Pass Nozzle	
TFA (in2)	0,720	(1/32 in)	

Date	28Aug2012
Designed By	CDD236WL4J\Administr
Approved By	

Figure B.2 Example of drill string information from the drilling program

B.3 DRILLING FLUID

An example of drilling fluid information from the drilling program is found in Figure B.3.

Depth meter	Inclination deg.	MW sg	Fann 3 rpm	YP Pa	PV	Gel 10s Pa	Gel 10m Pa	HTHP Disc FL	HTHP Disc spurt		Stability Volt	Ex.Lime kg/m3	O/W Ratio	Chloride g/l	LGS kg/m3	Sag stability
2 934 - 3 100		1.40	2-3	na	ALAP	>2	<15	<4	< 1		≥ 600	6 - 10	75/25 - 85/15	90-120	< 200	0.1

Product usage	Conc. (unit/m³)				Volumes	
	Unit	New	Maint	Tot Units		m³
					SURFACE	160
WARP Oil-Base concentrate	m3	0.3		50	RISER	3
Emul HT	kg	42		1 600	CASING / LINER	97
Bentone 128	kg	12		800	OPEN HOLE	4
Versatrol	kg	17		900	DILUTION	0
Lime	kg	20		1 600	HOLE TOT	104
CaCl2 powder	kg	33		800	LOST ON CUTTINGS	62
Water	m3	0.153			LOST IN HOLE	0
					TOT. VOL.	326
Contingency:					RECEIVED	260
EMI-1769	l	0		0	MIXED	66
Safe-Scav HSN	can	0		0	MUD LEFT	244
					BACKLOADED	244
					Dilution OH (m3/m3)	15.0
Bridging:						
VK 150 (CaCO3 M)	kg	10		3000		
G-Seal	kg	32		15000		
Safe-Carb 500	kg	28		14000		

Figure B.3 Example of drilling fluid information in the drilling program

Appendix C

PLANNING AND DESIGN DATA FROM THREE WELLS

C.1 WELLBORE TRAJECTORY

C-39 A

Table C.1 Planned and actual wellbore trajectory of C-39 A

	MD	Inc	Azi	TVD
Drilling program	2620,00	39,85	184,57	2236,89
	2643,00	40,89	187,56	2254,39
	2802,51	57,5	189,39	2356,79
	2932,45	50	175	2433,83
	2964,45	50	175	2454,4
	3150,29	50	175	2573,85
Compass Planned	**MD**	**Inc**	**Azi**	**TVD**
	2800,00	49,95	183,00	2367,07
	2825,00	52,59	183,73	2382,59
	2862,16	56,59	187,62	2404,12
Compass Actual	**MD**	**Inc**	**Azi**	**TVD**
	2807,1	51,76	182,72	2371,6
	2947	48,28	195,34	2455,6
	2975,6	52,26	196,41	2473,9
	3060,9	52,82	197,55	2526,2

C-13 A

Table C.2 Planned and actual trajectory of C-13 A

	MD	Inc	Azi	TVD
Drilling program	2967,0	40,12	142,67	2598,89
	2980,0	40.73	141,08	2606,47
	3030,0	36,47	136,87	2645,54
	3080,0	32,39	131,75	2686,78
	3120,0	32,39	131,75	2720,56
	3150,0	32,39	131,75	2745,89
EDM Planned	**MD**	**Inc**	**Azi**	**TVD**
	2967,00	40,15	142,05	2595,85
	2980,00	40,76	140,46	2605,72
	3030,00	36,50	136,26	2644,77
	3080,00	32,42	131,14	2686,00
	3120,00	32,42	131,14	2719,76
	3151,37	32,42	131,14	2746,24
EDM Actual	**MD**	**Inc**	**Azi**	**TVD**
	2960,0	40,20	142,00	2590,5
	2981,5	41,53	136,27	2606,7
	3038,9	38,26	128,51	2650,3
	3076,6	35,07	127,52	2680,7
	3127,9	37,90	132,99	2722,4
	3143,0	37,23	133,64	2734,4

C-9 AT2

Table C.3 Planned and actual trajectory of C-9 AT2

	MD	Inc	Azi	TVD
Drilling program	787,00	21,13	320,78	772,16
	1309,55	30,00	225,00	1260,00
	1855,74	45,00	225,00	1700,00
	2317,98	60,00	225,00	2000,00
	3014,88	80,00	225,00	2317,00
	3330,84	88,00	225,00	2350,00
	3703,74	88,00	225,00	2363,01
	4227,30	55,08	225,33	2526,53
	4841,75	20	225,00	2979,40
	5041,75	20	225,00	3167,34
EDM Planned	**MD**	**Inc**	**Azi**	**TVD**
	773,00	20,12	319,30	759,12
	1303,01	30,00	225,00	1260,00
	1859,21	45,00	225,00	1700,00
	2311,45	60,00	225,00	2000,00
	3008,34	80,00	225,00	2317,00
	3324,30	88,00	225,00	2350,00
	3710,78	88,00	225,00	2363,49
	4247,45	54,34	227,67	2534,24
	4845,90	20,00	225,00	2979,40
	5045,90	20,00	225,00	3167,34
EDM Actual	**MD**	**Inc**	**Azi**	**TVD**
	790,00	20,39	318,78	774,77
	1310,00	29,22	235,29	1267,05
	1860,00	45,14	221,02	1694,77
	2320,00	57,90	225,30	1999,11
	3010,00	76,78	224,51	2312,02
	3330,00	87,44	226,85	2346,86
	3700,00	88,03	224,10	2359,74
	4224,09	56,61	226,35	2512,76
	4853,59	22,30	225,35	2978,98
	4897,64	24,24	227,36	3019,44

C.2 BHA

Please note that the following presentations of BHAs are rough and with a low degree of detail. The presentations are given to emphasize the large changes that sometimes are made in BHA tallies from the early planning stage to the actual drilling run.

C-39 A

Table C.4 Planned and actual BHA in 8.5" section in C-39 A (simplified)

C-39 A BHA Drilling Run #1				
Planned Drilling Program	**String component**	**OD inch**	**Length m**	**Acc length m**
	PDC Bit	8,5	0,30	0,30
	Powerdrive RSS	8,1	4,15	4,46
	Stabilizer	8,385	1,52	5,98
	MWD and collars	~ 7	34,97	40,95
	HWDP and jar	6,5	117,50	158,45
Planned DOP	**String component**	**OD inch**	**Length m**	**Acc length m**
	Insert bit	8,5	0,25	0,25
	Powerpak PDM	8,375	7,30	7,55
	Stabilizer	8,250	1,80	9,91
	MWD and collars	~ 7	33,00	42,91
	HWDP an jar	6,50	121,96	164,87
Actual DBR	**String component**	**OD inch**	**Length m**	**Acc length m**
	PDC Bit	8,5	0,25	0,25
	Powerpak PDM	8.375	7,30	7,55
	Stabilizer	8,250	1,80	9,91
	MWD and collars	~ 7	33,00	42,91
	HWDP and jar	6,625	121,96	164,87

Table C.5 Planned and actual BHA in 6" section in C-39 A

	C-39 A BHA Drilling Run #2			
Planned Drilling Program	**String component**	**OD inch**	**Length m**	**Acc length m**
	PDC Bi-center bit 6" x 7"	7,500	0,23	0,23
	Bit sub	4,750	1,52	1,76
	MWD w/2xstab and collars	4,750 / 5,875	40,94	42,70
	HWDP and jar	3,500	109,15	151,85
Planned DOP	**String component**	**OD inch**	**Length m**	**Acc length m**
	PDC Bi-center bit 6" x 7"	6,000	0,44	0,44
	Bit sub	4,750	1,01	1,45
	MWD w/2xstab and collars	4,750 / 5,875	43,58	45,03
	HWDP and jar	3,500	92,55	137,58
Actual DBR	**String component**	**OD inch**	**Length m**	**Acc length m**
	PDC Bi-center bit 6" x 7"	6,000	0,20	0,20
	Bit sub	4,750	1,70	1,90
	MWD w/2xstab and collars	4,750 / 5,714	43,13	45,03
	HWDP and jar	3,500	93,99	139,02

C-13 A

Table C.6 Planned and actual BHA in 8,5" section in C-13 A

	C-13 A BHA Drilling Run #1			
Planned Drilling Program	String component	OD inch	Length m	Acc length m
	PDC Bit	8,5	0,30	0,30
	PowerDrive RSS	8,1	4,15	4,46
	Stabilizer	6,750	1,52	5,98
	MWD and collars	~ 6,890	27,16	33,14
	HWDP and jar	6,500	81,5	114,64
Planned DOP	String component	OD inch	Length m	Acc length m
	PDC Bi-center bit 8,5" x 9,5"	9,5	0,30	0,30
	PowerPak PDM	6,750	8,23	8,53
	MWD and collars	6,875/6,500	43,4	51,93
	HWDP and jar	5,000/6,500	118,5	170,43
Actual DBR	String component	OD inch	Length m	Acc length m
	PDC Bi-center bit 8,5" x 9,5"	9,5	0,41	0,41
	PowerPak PDM	6,750	8,23	8,64
	MWD and collars	6,875	44,97	53,61
	HWDP* and jar	3,375/6,563	122,04	175,65
	*Error in Daily report? HWDP OD 3,375 in			

Table C.7 Planned and actual BHA in 6 ½" x 7 ½" section in C-13 A

	C-13 A BHA Drilling Run #2				
Planned Drilling Program	String component	OD inch	Max OD	Length m	Acc length m
	PDC Bi-center bit 6,5" x 7,5"	7,5	7,5	0,23	0,23
	Bit sub	4,750		1,52	1,76
	MWD w/2xstab and collars	4,750	5,875	40,23	41,99
	3 ½" DP and jar	3,500 / 4,750		109,14	151,13
Planned DOP	String component	OD inch	Max OD	Length m	Acc length m
	PDC Bi-center bit 6,5" x 7,5"	7,5		0,41	0,41
	Bit sub	4,510		0,76	1,17
	MWD w/stab and collars	4,510 / 4,750	5,875	32,73	33,90
	3 ½" DP and jar	3,500 / 4,750		83,93	117,83
Actual DBR	String component	OD inch	Max OD	Length m	Acc length m
	PDC Bi-center bit 6,5" x 7,5"	7,5		0,41	0,41
	Bit sub	4,813		0,76	1,17
	MWD w/2xstab and collars	4,750 / 5,875		32,72	33,89
	3 ½" DP and jar	3,500 / 4,813		83,93	117,82

C-9 AT2

Table C.8 Planned and actual BHA in 17,5” section in C-9 A

	C-9 A BHA Drilling Run #4				
Planned Drilling Program	**11.10.12**	**BHA weight: 39,0 tons**			
	String component	**OD inch**	**Max OD**	**Length m**	**Acc length m**
	PDC Bit	9,060	17,500	0,42	0,42
	PowerDrive X5 RSS	9	17,250	4,28	4,70
	MWD, LWD,3xstab	9,0-9,5	17,250	23,06	27,76
	NM Collars	9,375/9,075	9,5	18,14	45,90
	Collars, jar	8,000/8,250	8,250	95,11	141,01
	HWDP	5,875	7,000	56,12	197,13
Planned DOP	**02.12.12**	**BHA weight: 30,9 tons**			
	String component	**OD inch**	**Max OD**	**Length m**	**Acc length m**
	PDC Bit	9,060	17,500	0,42	0,42
	PowerDrive X5 RSS	9	17,250	4,28	4,70
	MWD, LWD,3xstab	9,0-9,5	17,250	23,23	27,93
	NM Collars	9,660/9,380	9,660	17,59	45,52
	Collars, jar	8,000/8,250	8,250	57,71	103,23
	HWDP	5,875	7,000	56,12	159,35
Actual DBR	**25.12.12**				
	String component	**OD inch**	**Max OD**	**Length m**	**Acc length m**
	PDC Bit		17,500	4,28	4,28
	PowerDrive X6 RSS		17,250	4,28	8,56
	MWD, LWD,3xstab		17,250	26,96	35,52
	NM Collars		9,438	8,39	43,91
	Collars, jar		8,250	55,99	99,90
	HWDP		7,250	56,10	156,00

Table C.9 Planned and actual BHA in 12,25”x14” section in C-9 A

	C-9 A BHA Drilling Run #10				
Planned Drilling Program	**17.10.12**				
	String component	**OD inch**	**Max OD**	**Length m**	**Acc length m**
	PDC Bit	12,250	12,250	0,32	0,32
	PowerDrive X5 RSS	9,000	11,960	4,21	4,53
	MWD, 3xstab, collars	8,375/8	12,125	33,67	38,20
	12 ¼” x 14” reamer	12,185	14,000	4,16	42,36
	Collars, stab, jar	8/8,250	12,063	69,23	111,59
	HWDP	5,875	7,000	84,13	195,72
Planned DOP	**19.01.13**				
	String component	**OD inch**	**Max OD**	**Length m**	**Acc length m**
	PDC Bit	12,250	12,250	0,36	0,36
	PowerDrive X5 RSS	9,000	11,960	4,21	4,57
	MWD, 3xstab, collars and jar	8,375/8	12,125	36,97	41,54
	12 ¼” x 14” reamer	12,185	14,000	4,04	45,48
	Collars, stab, jar	8/8,250	12,063	69,48	114,96
	HWDP	5,875	7,000	84,13	199,09
Actual DBR	**20.01.13**				
	String component	**OD inch**	**Max OD**	**Length m**	**Acc length m**
	PDC Bit	12,250	12,250	0,36	0,36
	PowerDrive X6 RSS		12,125	8,79	9,15
	MWD, 2xstab, collars	8,250	12,125	32,38	41,53
	12 ¼” x 14” reamer	12,000	14,000	3,93	45,46
	Collars, stab, jar	8,250/8	12,125	68,17	113,63
	HWDP	5 7/8”	7,250	84,18	197,81

Table C.10 Planned and actual BHA in 8,5” section in C-9 A

	C-9 A BHA Drilling Run #12				
Planned Drilling Program	**11.10.12**				
	String component	**OD inch**	**Max OD**	**Length m**	**Acc length m**
	PDC Bit	8,500	8,500	0,25	0,25
	PowerDrive X5 RSS	6,730	6,730	4,08	4,33
	MWD, 3xstab, collars	6,750	8,375	31,21	35,54
	HWDP and jar	5,000/6,500	6,500	48,14	83,68
Planned DOP	**19.02.13**				
	String component	**OD inch**	**Max OD**	**Length m**	**Acc length m**
	PDC Bit	8,500	8,500	0,25	0,25
	PowerDrive X5 RSS	6,730	6,730	4,08	4,33
	MWD, 3xstab, collars	6,750	8,375	43,2	47,53
	HWDP and jar	5,000/6,500	6,500	36,84	84,37
Actual DBR	**20.02.13**				
	String component	**OD inch**	**Max OD**	**Length m**	**Acc length m**
	PDC Bit	8,500	8,500	0,22	0,22
	PowerDrive X6 RSS	6,750	6,750	8,78	9,00
	MWD, 2xstab, collars	6,750	8,250	47,58	56,58
	HWDP and jar	5,000/6,688	6,688	27,96	84,54

Table C.11 Planned and actual BHA in 6”x7” section in C-9 A

	C-9 A BHA Drilling Run #15				
Planned Drilling Program	**12.10.12**				
	String component	**OD inch**	**Max OD**	**Length m**	**Acc length m**
	PDC Bi-center bit 6” x 7”	7,000	7,000	0,44	0,44
	Bit sub	4,750	4,750	0,60	1,04
	MWD,2xstab, collars	4,750	5,875	56,51	51,55
	HWDP and jar	3,500/4,750	4,750	109,14	160,69
Planned DOP	**08.03.13**				
	String component	**OD inch**	**Max OD**	**Length m**	**Acc length m**
	PDC Bi-center bit 6” x 7”	7,000	7,000	0,44	0,44
	Bit sub	4,750	4,750	1,02	1,46
	MWD,2xstab, collars	4,750	5,875	53,31	54,77
	HWDP and jar	3,500/4,750	4,750	105,59	160,36
Actual DBR	**11.03.13**				
	String component	**OD inch**	**Max OD**	**Length m**	**Acc length m**
	PDC Bi-center bit 6” x 7”	7,000	7,000	0,45	0,45
	Bit sub	4,750	4,750	1,02	1,47
	MWD,2xstab, collars	4,750	5,875	53,32	54,79
	HWDP and jar	3,500/4,750	4,750	103,1	157,80

C.3 DRILLING FLUID

The following tables show the values belonging to the graphs in Section 4.4.4, with some additional information.

C-39 A

Table C.12 Planned and actual drilling fluid properties for C-39 A

C-39 A Drilling fluid						
8 ½" section (2610-2934)						
Start: 04.10.12 16:15			End: 05.10.12 03:30			
	Drilling program	EDM	04.10.12 14:00	04.10.12 20:00	05.10.12 01:10	05.10.12 13:00
Depth [m MD]	-	-	2824	2862	2903	2925 (TD)
MW in/out [sg]	1,56-1,58	1,55	1,52/0,00	1,53/1,52	1,55/0,00	1,55/1,55
Fann 600 rpm	-	38	103	105	106	108
Fann 300 rpm	-	22	60	61	62	69
Fann 200 rpm	-	16	45	45	46	47
Fann 100 rpm	< 30	16	29	29	29	30
Fann 60 rpm	-	10,5	22	22,5	22,5	23
Fann 30 rpm	-	6,5	16	16,5	16	17
Fann 6 rpm	-	4	9,5	10	10	11
Fann 3 rpm	7-15	2	8,5	8,5	9	9,5
Gel 10 s [Pa]	-	-	5,5	5,0	5,5	6,5
Gel 10 m [Pa]	≤ 20	-	8,0	8,0	8,0	8,5
Test temp	-	50	50	50	50	50
HTHP [ml]	2-4	-	1,7	2,0	2,4	2,2
Temp in/out	-	-	22/	43/50	56/62	55/61
*Started weighting up to 1,55 around 21:00						
6"x7" section (2927-3071,5)						
Start: 09.10.12 08:00			End: 10.10.12 00:45			
	Drilling program	EDM	09.10.12 14:00	09.10.12 19:30	10.10.12 01:00	
Depth [m MD]	-	-	2943	3016	3071,5 (TD)	
MW in/out [sg]	1,40	1,38	1,38/1,38	1,38/1,38	1,38/1,38	
Fann 600 rpm	-	43	38	40	43	
Fann 300 rpm	-	24	22	23	24	
Fann 200 rpm	-	19	16	17	19	
Fann 100 rpm	< 30	13	10,5	12	13	
Fann 60 rpm	-	10	8,5	9	10	
Fann 30 rpm	-	7	6,5	7	7	
Fann 6 rpm	-	6	4	5	6	
Fann 3 rpm	2-3	3	2,5	3	3	
Gel 10 s [Pa]	> 2	-	2,0	2,5	3,0	
Gel 10 m [Pa]	< 15	-	2,5	3,0	3,5	
Test temp	-	50	50	50	50	
HTHP [ml]	2-4	-	-	-	-	
Temp in/out	-	-	41/38	35/43	45/48	

C-13 A

Table C.13 Planned and actual drilling fluid properties for C-13 A

C-13 A Drilling fluid						
8 ½"x9 ½" section (2977-3089)						
Start: 02.09.12 04:00			End: 03.09.12 07:30			
	Drilling program	EDM	02.09.12 04:00	02.09.12 10:00	02.09.12 21:00	03.09.12 08:00
Depth [m MD]	-	-	2976	3003	3058	3081
MW in/out [sg]	1,54	1,50	1,50/1,50	1,50/1,50	1,50/1,50	1,50/1,50
Fann 600 rpm	-	99	97	95	98	94
Fann 300 rpm	-	59	59	58	61	58
Fann 200 rpm	-	43	45	45	46	45
Fann 100 rpm	-	28	30	30	30	30
Fann 60 rpm	-	22	24	25	25	24
Fann 30 rpm	-	16	18	19	19	19
Fann 6 rpm	-	9	14	14	14	14
Fann 3 rpm	7-15	8	10	12	11	12
Gel 10 s [Pa]	-	-	6,5	7,0	7,0	7,5
Gel 10 m [Pa]	≤ 20	-	8,5	9,0	8,5	9,0
Test temp	-	60	50	50	50	50
HTHP [ml]	2-4	-	2,5	2,2	2,2	1,8
Temp in/out	-	-	32/26	48/54	57/62	58/65
6 ½"x7 ½" section (3089-3149,3)						
Start: 08.09.12 09:45			End: 08.09.12 18:30			
	Drilling program	EDM	07.09.12 05:00	07.09.12 22:45	08.09.12 13:00	08.09.12 16:00
Depth [m MD]	-	-	3089	3089	3096	3120
MW in/out [sg]	1,40	1,22	1,50/1,50	1,22/0,00	1,22/1,22	1,22/1,22
Fann 600 rpm	-	40	95	22	26	26
Fann 300 rpm	-	26	57	14	16	16
Fann 200 rpm	-	20	43	11	12	12
Fann 100 rpm	-	14	28	8	8	8
Fann 60 rpm	-	-	22	7	7	7
Fann 30 rpm	-	-	16	4	5	5
Fann 6 rpm	-	6	14	4	4	4
Fann 3 rpm	2-3	5	10	3	3	3
Gel 10 s [Pa]	> 2	-	5,5	2,0	2,0	2,0
Gel 10 m [Pa]	< 15	-	6,5	2,5	2,5	2,5
Test temp	-	50	50	50	50	50
HTHP [ml]	-	-	1,6	-	-	-
Temp in/out	-	-	43/48	30/ -	30/35	33/38

C-9 AT2

Table C.14 Planned and actual drilling fluid properties for C-9 AT2 17,5" and 12,25"x14"

C-9 AT2 Drilling fluid						
17,5" section (773-2149)						
Start: 25.12.12 18:15			End: 06.01.13 07:15			
	Drilling program	EDM #1-#2	EDM #3-#4	25.12.12 17:00	27.12.12 16:30	03.01.13 17:00
Depth [m MD]	-	-	-	776	1216	1513
MW in/out [sg]	1,20-1,52	1,20	1,46	1,20/1,20	1,31/1,31	1,42/1,41
Fann 600 rpm	-	94	101	54	68	83
Fann 300 rpm	-	57	61	33	39	51
Fann 200 rpm	-	44	56	24	29	39
Fann 100 rpm	< 30	28	31	16	20	27
Fann 60 rpm	-	22	25	13	16	21,5
Fann 30 rpm	-	17	19	10	13	17,5
Fann 6 rpm	-	11	12,5	7	8,5	11
Fann 3 rpm	7-15	10	11	6	7,5	10
Gel 10 s [Pa]	-	-	-	4,0	4,5	6,5
Gel 10 m [Pa]	≤ 20	-	-	6,5	6,5	4,5
Test temp	-	21,111	21,111	50	50	50
HTHP [ml]	2-4	-	-	2,2	1,6	1,2
Temp in/out	-	-	-	24/33	49/52	48/52
12 ¼"x14" section (2149-4208)						
Start: 22.01.13 03:30			End: 30.01.13 08:30			
	Drilling program	EDM #1	EDM #2	21.01.2013 22:00	22.01.2013 21:00	23.01.2013 22:00
Depth [m MD]	-	-	-	2154,0	2353,0	2790,0
MW in/out [sg]	1,58	1,56	1,60	1,58/0,00	1,58/1,58	1,58/1,58
Fann 600 rpm	-	105	98	82,0	89,0	94,0
Fann 300 rpm	-	62	56	48,0	52,0	54,0
Fann 200 rpm	-	46	42	35,0	39,0	40,0
Fann 100 rpm	< 30	29	27	24,0	26,0	27,0
Fann 60 rpm	-	22	20	18,0	20,0	20,0
Fann 30 rpm	-	16	14	14,0	15,0	14,0
Fann 6 rpm	-	11	9	9,0	10,0	9,0
Fann 3 rpm	7-15	9	7,5	8,0	8,0	8,0
Gel 10 s [Pa]	-	-	-	5,0	5,5	5,5
Gel 10 m [Pa]	≤ 20	-	-	6,5	7,5	7,5
Test temp	-	21,111	21,111	50	50	50
HTHP [ml]	2-4	-	-	1,8	3,6	2,5
Temp in/out	-	-	-	35/ -	58/61	60/69

Table C.15 Planned and actual drilling fluid properties for C-9 AT2 8,5” and 6”x7”

C-9 AT2 Drilling fluid						
8,5” section (4216,5-4827)						
Start: 21.02.13 18:00			End: 24.02.13 22:30			
	Drilling program	EDM #1	EDM #2	20.02.2013 22:00	21.02.2013 22:00	22.02.2013 22:10
Depth [m MD]	-	-	-	4212,0	4217,0	4479,0
MW in/out [sg]	1,40	1,40	1,40	1,40/0,00	1,40/1,40	1,40/1,40
Fann 600 rpm	-	40	33	36,0	41,0	46,0
Fann 300 rpm	-	24	19	21,0	24,0	27,0
Fann 200 rpm	-	19	14	15,0	18,0	20,5
Fann 100 rpm	< 20	13	9	10,0	12,0	14,0
Fann 60 rpm	-	10	7	7,5	9,0	10,5
Fann 30 rpm	-	7	6	5,5	7,0	8,0
Fann 6 rpm	-	5,5	4	5,0	6,0	7,0
Fann 3 rpm	2-3	4,5	2,5	3,0	4,0	5,0
Gel 10 s [Pa]	≥ 2	-	-	2,0	2,5	3,0
Gel 10 m [Pa]	< 15	-	-	2,5	3,5	3,5
Test temp	-	50	50	50,0	50,0	50,0
HTHP [ml]	< 4	-	-	2,5	-	-
Temp in/out	-	-	-	- / -	41/44	56/62
6”x7” section (4830-4907)						
Start: 11.03.13 07:45			End: 11.03.13 13:45			
	Drilling program	EDM #1	10.03.13 23:00	11.03.13 05:00	11.03.13 11:00	11.03.13 17:00
Depth [m MD]	-	-	4827,0	4827,0	4862,0	4907,0
MW in/out [sg]	1,20	1,10	1,09/1,09	1,20/1,20	1,20/1,20	1,20/1,20
Fann 600 rpm	-	35	26,0	33,0	33,0	32,0
Fann 300 rpm	-	22	15,0	19,0	18,5	18,0
Fann 200 rpm	-	17	11,0	15,0	14,0	13,5
Fann 100 rpm	< 20	12	8,0	10,0	9,5	9,0
Fann 60 rpm	-	9	7,0	8,0	7,5	7,5
Fann 30 rpm	-	7	5,5	6,0	6,0	5,5
Fann 6 rpm	-	5	4,0	4,0	4,5	4,0
Fann 3 rpm	2-3	4	3,0	3,5	3,5	3,5
Gel 10 s [Pa]	≥ 2	-	2,0	2,5	3,0	3,0
Gel 10 m [Pa]	< 15	-	2,5	3,5	4,0	3,5
Test temp	-	50	50	50	50	50
HTHP [ml]	< 4	-	-	-	-	-
Temp in/out	-	-	33/35	33/35	32/36	33/36