NTNU – Trondheim
Norwegian University of
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Utilizing Managed Pressure Casing Drilling in Depleted Reservoir Zones

Tarje Livik Naterstad

Petroleum Geoscience and Engineering
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Supervisor: Sigbjørn Sangesland, IPT

Norwegian University of Science and Technology
Department of Petroleum Engineering and Applied Geophysics

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Norges teknisk-naturvitenskapelige universitet

Fakultet for ingeniørvitenskap og teknologi
Faculty of Engineering and Technology

Studieprogram i Geofag og petroleumsteknologi
Study Programme in Earth Sciences and Petroleum Engineering

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HOVEDOPPGAVE/DIPLOMA THESIS/MASTER OF SCIENCE THESIS

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Oppgavens tittel, norsk/Title of Thesis, *Trykkstyrt foringsrørboring i reservoarsoner med lavt trykk*

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Utfyllende tekst/Extended text:

Background:

Drilling wells through depleted reservoirs and layered reservoirs with different pressure regimes is a challenge using conventional drilling methods. It is believed that combining Managed Pressure Drilling (MPD) and Casing/Liner Drilling (CD/LD) may provide a method for drilling such wells from floating rigs in a safe and efficient manner. This thesis will discuss status and further perspectives of Managed Pressure Casing Drilling (MPCD) and how this combination may interact with other novel drilling techniques in order to further improve drilling performance in harsh conditions.

Task:

a. Discuss the current state of MPD and CD/LD technology (tools and equipment)
b. Describe typical challenges encountered when using MPD and CD/LD
c. Evaluate MPD & CD/LD, and the potential of combining the two techniques
d. Develop a hydraulic model applicable for MPD and CD/LD
e. Apply the hydraulic model on a case study in order to evaluate the performance when using conventional drilling methods, MPD, CD/LD and MPCD. Compare and discuss results

Supervisor:	*Professor Sigbjørn Sangesland (NTNU)*
Co-supervisor:	*Inge Manfred Carlsen & Jafar Abdollahi (Weatherford Petroleum Consultants A/S)*
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Summary

The last decade has seen the advent of new unconventional drilling methods, such as Managed Pressure Drilling and Casing/Liner Drilling. It has been proven through numerous field applications that both of these technologies bring value to drilling operations when used in the appropriate situations. It is thought that a combination of the two might yield additional benefits. Examples of candidates thought to benefit from using this combination include:

- Highly depleted reservoirs
- Formations with very narrow mud windows
- Consecutive layers with different pressure regimes

This thesis sets out to evaluate the benefits and limitations of combining these two methods into a method dubbed Managed Pressure Casing Drilling, and if it enables drilling wells that were previously thought undrillable. A hydraulic model was developed, combined with field data pertaining to a developed field on the Norwegian Continental Shelf, and used to model the pressure losses along a designed wellbore for four different cases:

- Conventional Drilling
- Liner Drilling
- Managed Pressure Drilling
- Managed Pressure Casing Drilling

The case study shows that out of these alternatives, the designed well can only be drilled using Managed Pressure Casing Drilling, though no consideration has been made with regards to limitations in well section length in this scenario; torque and drag, among others, are likely to limit the achievable well section length.

It has been found that the methods are complementary, provided that modifications are made to certain rig components. Using a combination of the two will lead to additional expenditures when constructing wells, but the findings in this thesis indicate that such a combination will bring significant value to certain drilling operations, provided careful candidate selection:

- Drilling with liner or casing in static underbalance, along with precise pressure management, may turn the increased Annular Friction Pressure associated with Casing/Liner Drilling into an advantage in some situations
- Reduced overbalance reduces the Rate of Penetration, stuck pipe, and formation damage concerns usually associated with Casing/Liner Drilling
- Reduces heave induced surge & swab pressure fluctuations when drilling ahead from floaters
- Allows drilling into highly depleted reservoirs and reservoirs with different pressure regimes, opening up new opportunities in drilling

This thesis should be treated as an initial study. Suggestions with regards to future work include, but is not limited to, studies pertaining to:

- The impact of overbalance on torque and drag
- The equipment and systems modifications required to accommodate the combination
- The impact of reduced overbalance on smearing, as well as fluid and particle invasion
- Hydraulic models used for automatic Managed Pressure Drilling systems. New models should be made to accommodate for:
    - the reduced annular flow area associated with Casing/Liner Drilling and the associated pressure losses
    - Surge and swab when drilling from floaters
- The economic benefits that may be gained by combining the two, preferably by analyzing well construction reports from fields similar to the candidates mentioned previously

Sammendrag

I løpet av de siste par tiår har boreindustrien begynt å ta i bruk nye og innovative boremetoder, som for eksempel trykkstyrt boring og boring med foringsrør. De individuelle fordelene tilknyttet bruk av disse nevnte metodene har blitt demonstrert gjentatte ganger ved bruk i felt, men på grunn av kostnaden benyttes de gjerne i spesifikke situasjoner. Man antar at man kan dra nytte av ytterligere fordeler ved å kombinere disse to. Det antas at en slik kombinasjon kan være spesielt fordelaktig ved bruk i følgende felttyper:

- Meget trykkavlastede reservoarer
- Formasjoner med svært trange slamvinduer
- Etterfølgende formasjonslag med varierende trykkregimer

Hensikten med denne avhandlingen er å evaluere fordeler og begrensninger som oppstår når man kombinerer disse to metodene, og om kombinasjonen kan bidra til et paradigmeskifte i industrien mtp. hva som anses å være borbart. En hydraulisk modell har blitt konstruert og kombinert med feltdata fra et felt på den norske kontinentalsokkelen for å bygge opp vurderingsgrunnlaget. Denne har blitt benyttet til å evaluere trykktapene langs en designet brønn for fire forskjellige tilfeller:

- Konvensjonelle boremetoder
- Foringsrørboring
- Trykkstyrt boring
- Kombinasjonen av de to sistnevnte: Trykkstyrt foringsrørboring

Denne vurderingen viser at det ikke er mulig å bore den designede brønnen med andre metoder enn trykkstyrt foringsrørboring ut av de nevnte alternativene. Det har ikke blitt tatt hensyn til begrensninger som måtte påvirke brønnseksjonslengde. I realiteten vil sannsynligvis brønnseksjonslengdene begrenses vesentlig av moment og vegg-til-vegg friksjon under boring.

I denne avhandlingen er det vist at metodene er komplementære, dersom riggen modifiseres for å akkomodere utstyret. Dette vil medføre ekstrakostnader tilknyttet boreoperasjoner, men det er også et potensial for betydelige besparelser og økte inntekter tilknyttet feltutvikling, forutsatt at potensielle kandidater vurderes nøye i forkant. I hovedsak kan man forvente å dra nytte de av de følgende fordelene:

- Det går an å utnytte friksjonstapet i annulus, som er en følge av boring med foringsrør, ved å bore i underbalanse med presis justering av baktrykk.
- Økning i penetrasjonsrate, en reduksjon av tilfeller hvor strengen blir sittende fast, samt redusert formasjonsskade i forhold til hva som normalt kan forventes når man borer med foringsrør.
- En reduksjon i trykkfluktuasjoner, som ofte kan observeres når det bores fra flytere som følge av bølgebevegelse.

- Nye muligheter tilknyttet boring av meget trykkavlastede reservoarer og formasjoner med svært trange slamvinduer, samt lagdelte reservoarer med forskjellige trykkregimer.

Denne avhandlingen bør vurderes som et innledende studie. Forslag til videre arbeid inkluderer, men er ikke begrenset til, å:

- Studere om redusert overbalanse i brønnen påvirker moment og vegg-til-vegg friksjon.
- Vurdere hva slags modifikasjoner som må gjennomføres på rigg og øvrig utstyr for å akkommodere trykkstyrt foringsrørboring.
- Forske på hvordan redusert overbalanse påvirker «smearing», samt fluid og partikkelinvasjon i formasjoner som bores.
- Videreutvikle hydrauliske modeller som benyttes til automatisk trykkstyr boring-operasjoner. Nye modeller bør utvikles for å ta høyde for:
    - Reduksjonen i strømningsareal i annulus
    - Trykkfluktuasjoner som følge av bølgebevegelse når det bores fra flytere
- Evaluere de økonomiske fordelene man kan dra nytte av ved å kombinere metodene. Dette kan for eksempel gjøres ved å samle data fra brønnrapporter fra brønner som har blitt boret i felt som passer beskrivelsen tidligere i sammendraget.

Acknowledgements

This thesis is the culmination of a five year study programme within the field of Petroleum Engineering (with the Department of Petroleum Engineering and Applied Geophysics) at the Norwegian University of Science & Technology. The work has been done together with Weatherford Petroleum Consultants A/S, in their offices.

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Abbreviations

AFP	Annular Friction Pressure
API	American Petroleum Institute
ASM	Along-String Measurements
BHA	Bottom Hole Assembly
BHP	Bottom Hole Pressure
BOP	Blowout Preventer
BP	Backpressure
CBHP	Constant Bottom Hole Pressure
CCS	Continuous Control System
CD	Casing Drilling
CFD	Computational Fluid Dynamics
DG	Dual Gradient Drilling
DLS	Dog-leg Severity
ECD	Equivalent Circulating Density
EMW	Equivalent Mud Weight
EOWR	End of Well Report
ERD	Extended Reach Drilling
ETD	Expandable Tubular Drilling
FEM	Finite Element Method
FIT	Formation Integrity Test
HPHT	High Pressure High Temperature
HSE	Health, Safety & Environment
LCM	Lost Circulation Material
LD	Liner Drilling

LOT	Leak-off Test
LWD	Logging While Drilling
MODU	Mobile Offshore Drilling Unit
MPCD	Managed Pressure Casing Drilling
MPD	Managed Pressure Drilling
MPT	Mud Pulse Telemetry
MSL	Mean Sea Level
MTBF	Mean Time Between Failure
MWD	Measurements While Drilling
NCS	Norwegian Continental Shelf
NPT	Non-Productive Time
NRV	Non-Return Valve
OBD	Overbalanced Drilling
PDM	Positive Displacement Motor
PHAR	Pipe-to-Hole Area Ratio
PI	Productivity Index
PMCD	Pressurized Mud Cap Drilling
POOH	Pulling Out of Hole
PWD	Pressure Measurements While Drilling
RCD	Rotating Control Device
RKB	Rotary Kelly Bushing
RIH	Run in Hole
ROP	Rate of Penetration
RPM	Revolutions per Minute
RSS	Rotary Steerable System
SG	Specific Gravity

SPP	Stand Pipe Pressure
SWD	Seismics While Drilling
TD	Target Depth
TRL	Technology Readiness Level
TVD	True Vertical Depth
UBO	Underbalanced Drilling
WBE	Well Barrier Element
WBS	Wellbore Stability
WDP	Wired Drill Pipe
WOB	Weight on Bit

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Nomenclature

Nominator	Unit	Description
A		
B_o	Sm^3/m^3	Formation Oil Factor
$c_{p,0}$	-	Cuttings Concentration Ratio
D	m	Diameter
d_{bit}	m	Bit Diameter
d_i	m	Inner Diameter
d_o	m	Outer Diameter
DLS	$^o/30m$	Dog-Leg Severity
ECD	Pa	Equivalent Circulating Density
ΔE	m	Horizontal Displacement in Eastern Direction
F	-	Ratio Factor
g	m/s^2	Gravity acceleration
h	m	Reservoir Layer Height
k	m^2	Permeability
K	-	Flow Consistency Index
K_{fr}	Pa	Drained Bulk Modulus
$K_{L,\ contraction}$	-	Singularity Loss Contraction Coefficient
$K_{L,\ expansion}$	-	Singularity Loss Expansion Coefficient
K_s	Pa	Bulk Modulus, Solid Material
L	m	Length
L	m	Length of Build-up
n	-	Flow Behavior Index
N_{RE}	-	Reynolds Number
p_f^{frac}	Pa	Fracture Pressure
p_{hs}	Pa	Hydrostatic Pressure
p_{wf}	Pa	Flowing Well Pressure
p_R	Pa	Reservoir Pressure
Δp	Pa	Pressure differential
Δp_f	Pa	Pressure loss due to friction
q	m^3/s	Fluid Flow Rate

Nominator	**Unit**	**Description**
q_{mud}	m^3/s	Mud Flow Rate
q_o	m^3/s	Oil Flow Rate
q_{solids}	m^3/s	Rate of Produced Solids
r_e	m	Drainage Radius
r_w	m	Well Radius
Q	m^3/s	Fluid Flow Rate
R	m	Radius of Build-up
ROP	m/hr	Rate of Penetration
$\overline{v}$	m/s	Average Velocity
ΔV	m	Vertical Displacement
ΔW	m	Horizontal Displacement in Western Direction

α	–	Biot's coefficient
α_1	^{o}	Inclination at the start of a build-up section
α_2	^{o}	Inclination at the end of a build-up section
β_1	^{o}	Azimuth at the start of a build-up section
β_2	^{o}	Azimuth at the end of a build-up section
$\dot{\gamma}$	s^{-1}	Shear Rate
$\dot{\gamma}_{annulus}$	s^{-1}	Shear Rate for Annular Flow
$\dot{\gamma}_{\iota}$	s^{-1}	Shear Rate @ *I* RPM
$\dot{\gamma}_{pipe}$	s^{-1}	Shear Rate for Pipe Flow
ε_x	m	Elongation/contraction in x-direction
ε_y	m	Elongation/contraction in y-direction
θ_i	Pa	Viscometer Reading @ *I* RPM
μ_o	Pa*s	Oil Viscosity
μ	Pa*s	Fluid Viscosity
μ_{eff}	Pa*s	Effective Viscosity
μ_{pl}	Pa*s	Plastic Viscosity
ν	-	Poisson's Ratio
ν	m^2	Kinematic Viscosity
ρ	kg/m^3	Density
ρ_{mix}	kg/m^3	Density of Mixed Solids and Fluids

Nominator	**Unit**	**Description**
ρ_{mud}	kg/m^3	Density of Mud
ρ_{solids}	kg/m^3	Density of Solids
σ_h	Pa	Minor Horizontal Stress
σ_H	Pa	Major Horizontal Stress
σ_v	Pa	Vertical Stress
τ	Pa	Shear Stress
τ_i	Pa	Shear Stress @ *I* RPM
τ_y	Pa	Yield Stress
φ	^{o}	Dog-Leg Angle

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Definitions

Annulus	The void between the drill string / production tubing and wellbore/casing.
Barrier	A well construction element that prevents unintended flow from producing layers into surrounding formations and/or environment
Bit Balling	The formation being drilled sticks to the bit, reducing bit efficiency and ROP, and potentially increasing string vibrations which may lead to component/string failure
Casing	A casing is a piece of metal tubing that is secured at the wellhead, and run all the way down to an appropriate depth.
Contingency	A provision for a possible event or circumstance. In the case of contingency casing, an intermediate casing intended to bridge the gap between two casing size in case it becomes necessary to set a casing earlier than originally intended.
Contractor	Drilling contractor refers to those individuals or group of individuals who own a drilling rig. Drilling contractors contract their services mainly for drilling wells. Drilling contractors also provide equipment, people and the expertise to drill wells, which can be either offshore or onshore.
Dog-leg Severity	A measure of the build-up rate in a well, quantified by well inclination change / length of well, usually $\Delta\alpha/30m$.
Drill String	In the context of this thesis, drill string can be understood as a column/string consisting of connected drill pipe and/or drilling tubulars (casing or liner) and/or BHA that transmits torque and fluids downhole.
Hook Load	The force pulling on the hook suspending the drill string. Hook load is used to measure the force required to pull the string out of the hole, or to estimate weight on bit during string running operations or drilling.
Liner	A liner is a casing string that is hanged off at the bottom of the previous casing string, typically with an overlapping section of 100m
Lost Circulation	Usually occurs when the BHP exceeds the fracture strength of a formation, or the formation is highly fractured, causing drilling fluids to leak into the formation
Managed Pressure Drilling	An advanced drilling technique where a well is drilled with mud gradient as close to the pore pressure of the formation as possible. Fluid influx while drilling is generally not desired, though some is acceptable.

Mud Window	The difference between the formation pore/ collapse pressure and fracture pressure.
Operator	An individual, company or trust responsible for the exploration, development and production of an oil or gas well or lease.
Overbalanced Drilling	A conventional drilling technique, where a well is drilled with mud gradient greater than the pore pressure in the formation. Fluid influx while drilling is not desired.
Pipe Stripping	The act of putting drillpipe into a well under pressure past annular seals
Service Company	A company which provides services to the petroleum exploration, development and production industry, but which typically produces no hydrocarbons themselves.
Sub	Any small component of the drill string
Telescope/Tapering Effect	The diameter of each consecutive liner/casing gets progressively smaller as consecutive casing strings are set and cemented in place
Top Drive	A device that rotates the drill string from the top. The top drive consists of one or more electric motors, and is suspended from the hook, making it free to move up and down in the derrick.
Underbalanced Drilling	An advanced drilling technique where a well is drilled with mud gradient less than the pore pressure in the formation. During drilling, the well takes a continuous influx of fluids from the formation. The goal is to eliminate wellbore damage caused by fluid invasion altogether if executed successfully. Going into overbalance, even for a very short period of time eliminates or severely reduces the magnitude of this advantage.
Well Ballooning/Breathing	A phenomenon occurring when a formation takes in drilling fluids when the pumps are turned on, and returning the mud to the wellbore when the pumps are shut off.

1 Introduction

Conventional drilling methods rely on relatively wide pore pressure and fracture pressure margins (commonly referred to as the *mud window*) in order to reach *Target Depth* (TD) in a safe and efficient manner. Drilling into severely depleted reservoirs, however, usually means drilling through narrow mud windows, and is very challenging or even impossible due to formation instability and associated operational challenges. The narrower the mud window, the greater the risk of encountering lost circulation events, hole collapse, loss of wellbore and blowouts, all of which may place the rig crew, company's assets and surrounding environment in jeopardy.

Pressurized fluids contained in microscopic pores act as pressure support in rock formations containing fluids. This aids in supporting the enormous weight of the rock mass in the overburden; there is a natural relationship between pore pressure and formation strength. As a producing reservoir is depleted, this pressure support decreases over time, with the consequence of reducing the strength of the rock in the reservoir; the mud window shrinks with increasing depletion.

The last decade or two has seen the advent of several novel drilling methods that are well suited to negating the aforementioned challenges. Methods like *Managed Pressure Drilling* (MPD) and *Casing/Liner Drilling* (CD/LD) are both known for counteracting different aspects of the challenges mentioned, as has been documented through numerous applications both on and off shore.

Important challenges ahead make it necessary to not just drill into, but also *through* depleted reservoir layers and into formations situated underneath. Drilling into formations with different pressure regimes, and indeed, *unknown* pressure regimes poses challenges that may be insurmountable using any of the novel methods mentioned above by themselves. Solving such challenges will allow the petroleum industry to drill into reservoirs previously thought unreachable and increase their hydrocarbon output. This has served as motivation for this thesis.

A solution to some aspects of this challenge may lie in blending these technologies. Both MPD and CD/LD techniques have their unique advantages, but also their respective limitations. Potential benefits of combining the two are evaluated in this Master's Thesis, as well as the potential challenges involved. In order to evaluate the viability of such a combination, a hydraulic model has been developed and applied by performing a case study. The case is based on publically available information gathered from an actual oil field on the *Norwegian Continental Shelf* (NCS).

Additional information has been gathered from open sources, published papers, books and discussions with industry professionals.

This Master's Thesis can be divided roughly into two parts:

1. The challenges involved as well as the different methods are presented and described in detail along with supporting technologies in order to provide a framework for the discussion.
2. These methods are evaluated alongside one another in order to identify potential pitfalls and complementary properties. The thesis contains a chapter describing the theoretical background of wellbore hydraulics, basic rock mechanics and wellbore geometry, which have all been used to develop a hydraulic model. The hydraulic model has been used to perform a case study in an attempt to compare conventional drilling methods with MPD, CD/LD, and a combination of MPD and CD/LD; *Managed Pressure Casing Drilling* (MPCD).

2 Technology

2.1 Adopting New Technology

Oil and gas resource exploration, development and production are technology intensive endeavors. The oil & gas industry is also one where safety is a serious concern; there have been many incidents throughout history where oil and gas activities have led to serious accidents causing the deaths of people and serious harm to the surrounding environment. Macondo (Deepwater Horizon), Alexander Kielland and Piper Alpha are but a few examples. Such accidents tend to have serious financial and political consequences for the responsible parties. With this in mind, it is hardly surprising that the industry tends to rely on tried and tested technology that experience proves to be reliable. In the world of drilling, this usually means using methods that has remained largely unchanged during the last century. This begs an important question: Has the industry come up with better solutions than the ones commonly used today? If so, why does the industry generally stick with the conventional approach?

The *Operator* industry as a whole is not heavily involved in research compared to other typical technology intensive industries, as is illustrated in Figure 2-1. Exceptions from the norm do exist, such as Chevron, Shell and Statoil, which are heavily involved in research projects. In general, it may seem as though the *Service* industry has adopted the role of developing and testing technology. This arrangement has some benefits in that the Operators may focus on their core business, which is finding and extracting hydrocarbons, while the Service providers may focus on technology and developing products for the Operators (Angus Warren, 2013).

It is in the Operators' interest to adopt technologies which may aid in increasing operational efficiency and safety while drilling, and productivity of the completed fields. In spite of this fact, the rate of which new technologies are adopted and used in field applications is lower than it could have been:

> *"The world's first 3D seismic survey was undertaken by ExxonMobil in 1967, but it was not until the mid-1980s that the technology became truly mainstream." "Horizontal drilling began in the USA in the mid-1970s, but it wasn't until the 1980s that steerable motors that could be controlled from the surface were introduced – that allowed the real growth in horizontal drilling to take place between 1990 and 2000* (Angus Warren, 2013)*."*

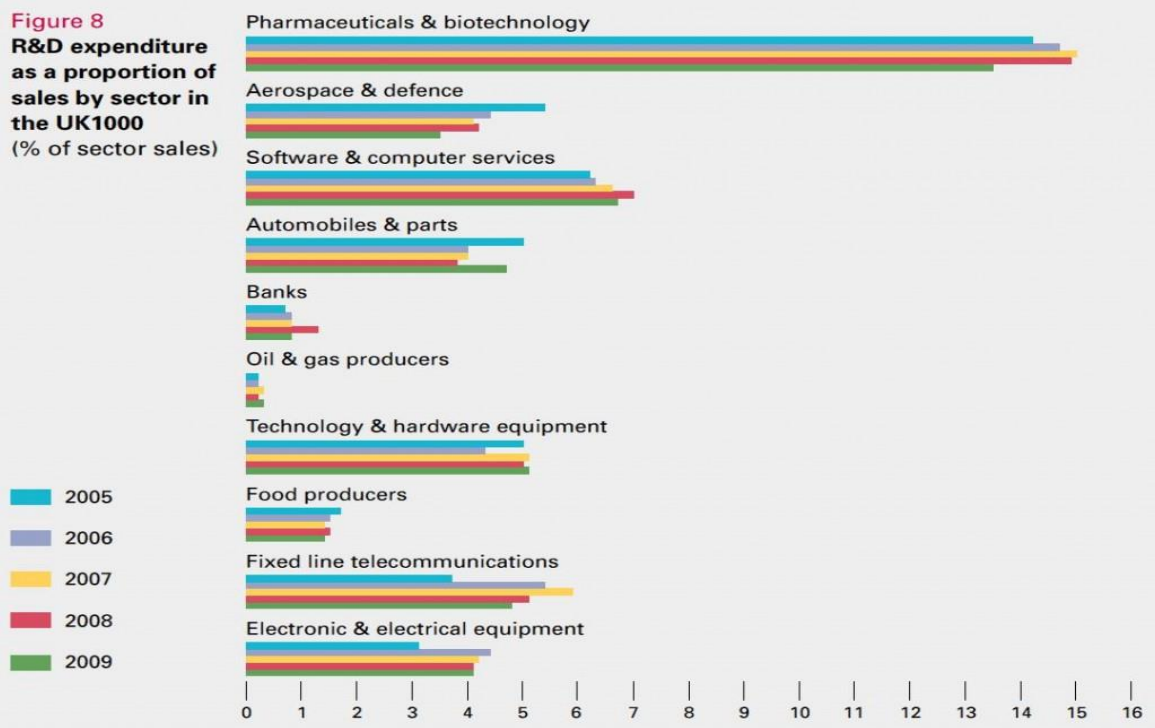

Figure 2-1: R&D expressed as percentage of sales or operating profit (Angus Warren, 2013)

There are several reasons as to why this is the case, some of which are listed below:

- There is a significant risk related to utilizing new technologies which has not been tested in the field.
  - Due to the potential catastrophic consequences (both to the company – politically and financially – , human lives and the environment), it is natural that Operators, as the main responsible party, wishes to reduce risk factors
- Due to continuous outsourcing of research endeavors, the company and its employees may not have the skills and knowledge required to properly understand the risk factors involved with certain technologies, and so may err on the side of caution
- Pressure from investors may incentivize Operator companies and its management to opt for the short-term advantage, rather than investing in long-term financial benefit

Several technologies exist today which have the potential of increasing efficiency of field development, as well as alleviate typical well control issues which may cause accidents. Even in the case of technologies with a documented field record, some Operators still seem somewhat apprehensive about using them for anything other than a “last resort” solution. MPD is an example of such a technology.

2.2 Flat Time

Flat Time:

> *"A common term used by many operators, encompassing all times except drilling ahead a new hole. This thus includes the planned normal operations, trouble time, lost time and well downtime, [...] and this also includes tripping between drilling sequences and completion operations"* (Carlsen, et al., 2000).

The causes of Flat Time include, but are not limited to:

- Tripping
- Stuck Pipe incidents
- Fishing
- Well Control Events
- Waiting on Weather (WOW)
- Casing running/installation
- Formation evaluation
- Completions

Table 1 and Table 2 presents Flat Time data based on 250 wells world-wide in which Mobil are/were either Operator or Partner. It has proven a challenge to find reliable flat time estimates that are representative for conditions on the NCS.

Table 2 shows that non-scheduled events such as lost circulation or well control, DH equipment failure and stuck pipe incidents, casing running & installation, tripping and formation evaluation constitutes a significant amount of time lost annually on the NCS. Figure 2-2 displays a breakdown of cost distribution of well operations on the NCS. Considering today's rig rates - ranging from ~$280k USD to ~$600k USD per day, depending on rig type, as of Aug. 2014, see Appendix A -, the discussions regarding MPD, *Wired Drill Pipe* (WDP), *Measurements While Drilling* (MWD) and *Logging While Drilling* (LWD), and the potential benefits these technologies have, it seems apparent that there is a significant savings potential involved.

As can be seen from Table 1, running and installation of casing typically constitutes 12-21% of flat time, tripping 10-12%, and formation evaluation 5-18%. That is between 20 and 38% of total drilling time in the North Sea.

Furthermore, stuck pipe incidents and fishing of equipment, lost circulation and/or well control events, and issues with downhole equipment constitutes further 4 to 18% of total drilling time.

Table 1: Flat Time of Total Time Drilling and Completion (Jenssen, et al., 2000)

Region	Flat Time [%]	Comment
Offshore Gulf of Mexico	82	Typical average for all wells
Offshore Equatorial Guinea	83	
North Sea	75	Both UK and NCS
Deepwater Gulf of Mexico	75	Beyond 400 meter water depth
Onshore USA (Texas, Louisiana)	65	Oil and Gas wells

Table 2: Flat Time - distribution of causes (Jenssen, et al., 2000)

Event, operation	Flat Time range % of total	Breakdown, comments
Non-scheduled events	12-25	Stuck pipe, fish: 2 - 12% DH equipment : 2 - 9% Lost circulation or well control: 1 - 3% WOW, waiting: 0.5 - 3% Cementing: 0.5 - 2%
Casing running/installation	12-21	Time consuming operation
Tripping	10-12	Reduced number of trips needed
Formation Evaluation	5-18	Mainly logging (as required)
Completion	5-10	Strongly influenced by well and completion type

The technologies discussed in this thesis will have the potential to reduce the time spent conducting many of the operations mentioned in Table 2, some by eliminating the source of Flat Time, for example running liner or casing while drilling, others indirectly by reducing damage to downhole components and improving operational efficiency.

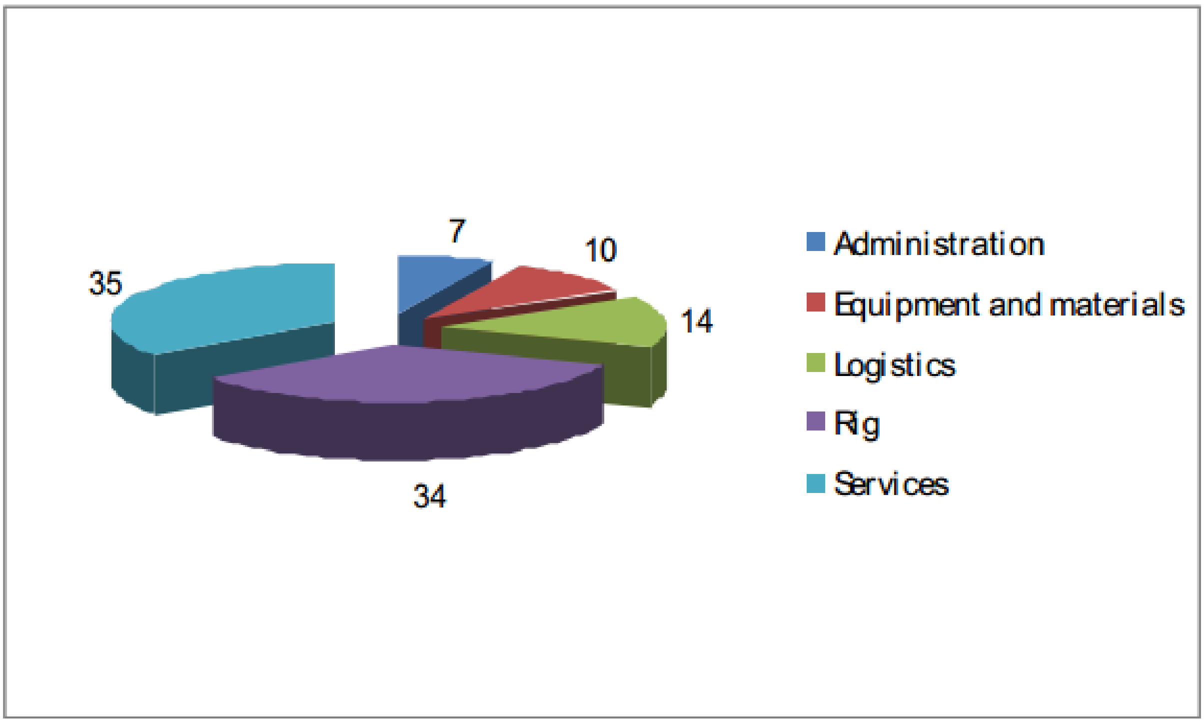

Figure 2-2: Cost Distribution on the NCS (Osmunsen, et al., 2009)

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3 Managed Pressure Drilling

Managed Pressure Drilling, according to the *International Association of Drilling Contractors* (IADC), is defined as *"an adaptive drilling process used to more precisely control the annular pressure profile throughout the wellbore"*. The objectives are *"to ascertain the down-hole pressure environment limits and to manage the annular hydraulic pressure profile accordingly"* (Hannegan, 2011).

"Basic to MPD planning and execution is the concept that it is an adaptive procedure (Rehm, et al., 2008)." The general concept is to establish a closed-to-atmosphere envelope, so that the *Bottom-Hole Pressure* (BHP) can be adjusted in a matter of seconds to accommodate changes in formation characteristics, and thereby avoid the influx of formation fluids and collapse of formation rocks.

When making up or breaking out connections, the circulation is halted and the pumps are shut off. Under static conditions, the BHP is determined by the static mud column alone (Eq. 3-1):

$$\boldsymbol{BHP_{static} = p_{static} = \rho_{fluid} * g * D} \qquad \textbf{Eq. 3-1}$$

When the rig pumps are turned on and the drilling fluids are circulating through the drill string and wellbore, the dynamic BHP of a circulating system may be expressed using the simple but fundamental pressure equation shown in Eq. 3-2 (Rehm, et al., 2008):

$$\boldsymbol{BHP_{dynamic} = p_{static} + \Delta p_{AFP}} \qquad \textbf{Eq. 3-2}$$

where

$\boldsymbol{p_{static}}$ = The hydrostatic pressure exerted on the bottom by the stationary drilling fluid column

$\boldsymbol{\Delta p_{AFP}}$ = The *Annular Friction Pressure* (AFP) caused by the circulating drilling fluid

The term $\boldsymbol{BHP_{dynamic}}$ expressed in Eq. 3-2 is also referred to as *Equivalent Circulating Density* (ECD), which the *American Petroleum Institute* (API) defines as "*the effective density of the circulating fluid in the wellbore resulting from the sum of the hydrostatic pressure imposed by the static fluid column and the friction pressure* (American Petroleum Institute, 2010)." It is also commonly referred to as *Equivalent Mud Weight* (EMW). In order to compensate for AFP Loss, the mud pumps topside must provide extra pressure in order to maintain circulation through the drill string, bit and up the annulus (Thingbø, 2011).

Using a *Rotary Control Device* (RCD), which will be described in more detail further on, or another similar pressure isolation device, enables operators to pressurize and isolate the well by establishing a so-called *Closed Loop System*. Separating between systems that are open to the atmosphere and systems that are closed to the atmosphere is essential in order to properly define some of the advantages of MPD systems.

In a Closed Loop System, the well is pressurized by applying *Backpressure* (BP), p_{BP}. Backpressure refers to the increased annular pressure generated using dedicated pumps and chokes. During connections, the backpressure is usually used to compensate for the lack of ECD induced while circulating. While drilling, the BP is used to regulate the wellbore pressure. This can be used to maintain a constant pressure at an arbitrary point in the well and/or to compensate for anticipated, as well as sudden pressure changes along the well bore. Pressure fluctuations along the wellbore may be caused by pipe movement, fluid losses and formation inhomogeneities, to mention a few examples. Maintaining a closed pressure envelope has the benefit that it prevents gases from leaking onto the rig deck, reducing the risk of crew exposure, as well as unintended leaks into the environment. This, in turn, reduces the risk of hydrocarbon ignition and resulting fire/explosion hazard (Rehm, et al., 2008).

The BHP of wells drilled using closed-loop MPD systems is estimated by Eq. 3-3, where the BHP is controlled by exploiting the AFP while circulating, and applying additional BP to compensate for reduced circulation:

$$\boldsymbol{BHP_{dynamic} = p_{static} + \Delta p_{AFP} + p_{BP}} \qquad \textbf{Eq. 3-3}$$

In order to avoid taking unwanted fluid influx, commonly referred to as *kicks*, the driller will always want to stay above the formation *Pore Pressure*, p_p, while drilling. However, the pore pressure is not necessarily the lower boundary for the BHP. The *formation wellbore stability pressure* is a function of the magnitude and direction of the *maximum horizontal stress*, (σ_H), well orientation in relation to σ_H, well inclination, drilling fluid rheology, formation density, pore pressure, porosity and permeability, as well as pumping rate, rotary speed and *Rate of Penetration* (ROP) (Rehm, et al., 2008). The BHP should always remain above whichever of the pore pressure and collapse pressure, p_f^{wbs}, is the highest, and below the *formation fracture pressure,* p_f^{frac}. Together, these boundaries constitute the *drilling window,* depicted in Figure 3-2. Figure 3-1 shows how backpressure is applied when circulation is halted to compensate for the lack of AFP loss. When circulating, the backpressure is dialed back.

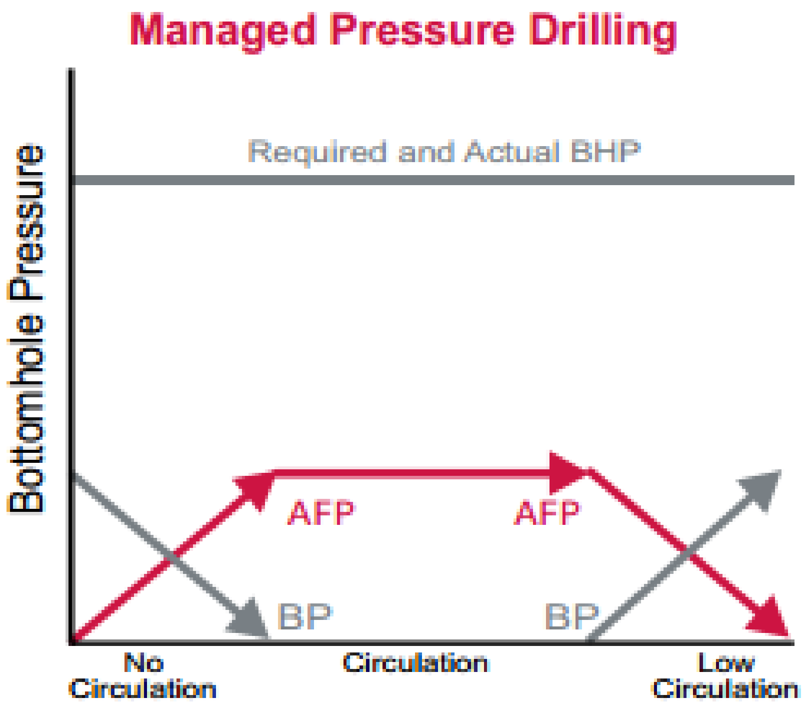

Figure 3-1: Constant Bottom-Hole Pressure MPD, Pressure Management (Weatherford International)

In contrast to *Overbalanced Drilling* (OBD), MPD techniques commonly facilitates the use of lower density drilling fluids, and relies on adjusting valves, chokes and pumps to manipulate the bottom hole pressure. Using MPD techniques means that the effective borehole pressure can be changed in a matter of seconds without having to circulate in new mud. Setting contingency casing strings has traditionally been the solution to most well control situations. Being able to dynamically change the effective bottom-hole pressure and keeping it close to the pore pressure has the benefit of enabling the casing points to be set deeper, which may allow the Operator to eliminate casing strings, reducing the time spent on constructing the well (Rehm, et al., 2008).

Reactive vs. Proactive MPD

Reactive MPD systems are set up as a contingency to quickly manage unintentional and unexpected influx and pressure spikes should they arise. The well is otherwise planned conventionally, using conventional hydraulic programs.

Proactive MPD systems use MPD tools and equipment actively in conjunction with downhole sensors (where available) throughout the drilling process to manage the bottom-hole pressure profile. As such, proactive setups are better suited to benefit from the potential of MPD techniques.

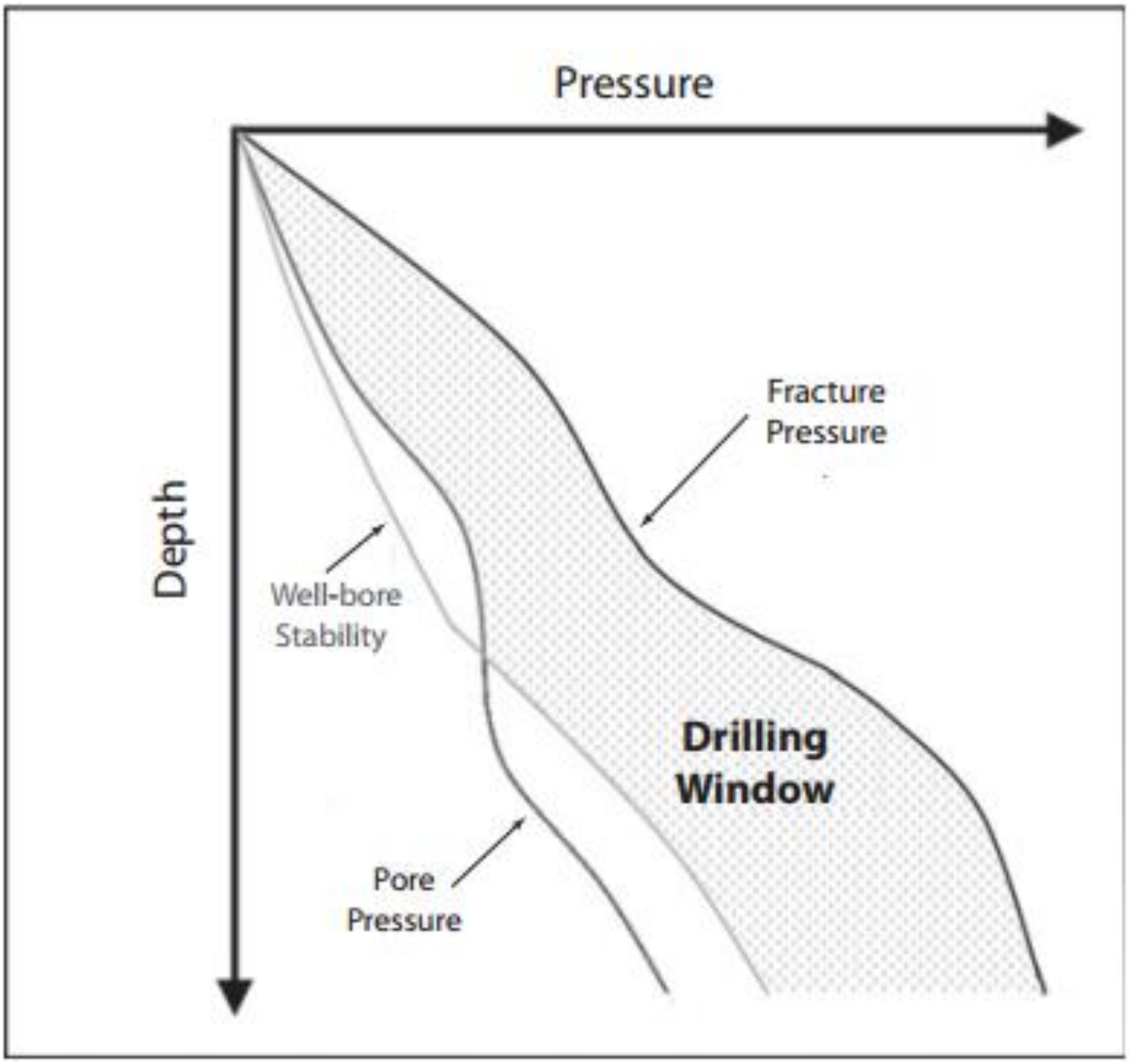

Figure 3-2: The drilling window is the area between the fracture pressure and pore pressure/well-bore stability (Rehm, et al., 2008).

3.1 The Managed Pressure Drilling Method

MPD is commonly referred to as being an *ad hoc* method; fit-for-purpose. Several techniques using different equipment and methodologies may be applied, each addressing different drilling-related challenges or hazards. Only one of them; *Constant Bottom Hole Pressure* (CBHP) MPD is deemed relevant for this thesis. Additional information on other techniques may be found in Appendix C. In some cases, combinations of different techniques may be deployed in several stages during the construction of a well.

The CBHP MPD technique aims to maintain a constant pressure at a fixed point in the well by controlling the annular back pressure. Figure 3-3 shows the gradients resulting from applying backpressure. CBHP is commonly used in order to avoid kicks or losses in situations where the drilling window is narrow or unknown, but also when dealing with fluctuating pressure situations and *well breathing / ballooning* complications (Mæland, 2013).

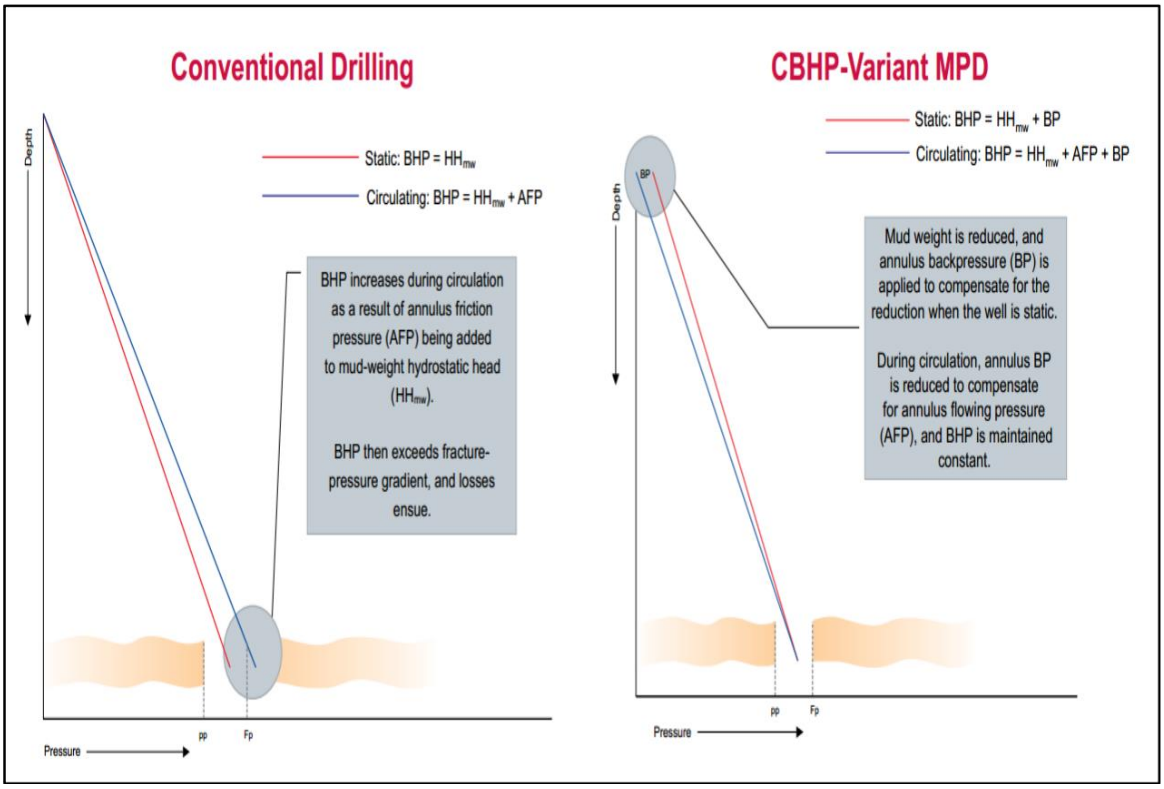

Figure 3-3: CBHP MPD: Pressure Gradients (Phade, 2013)

3.2 Tools and Equipment

The following chapter provides a general description of the most common types of tools used in MPD operations. A more comprehensive list of tools can be found in Appendix C.

3.2.1 Rotating Control Device

The RCD is the heart of all MPD systems. It is designed to maintain a pressure-tight barrier between the fluid returns and personnel on the rig floor/atmosphere, while enabling circulation of drilling fluids by utilizing the continuous circulation system, even while making connections or tripping. The RCD is a rotating packer that uses an annular seal element or "stripper rubber," which is 1/2" to 7/8" diameter undersize to the drill pipe and is force fit onto the pipe. In order to maintain a pressure-tight barrier while tripping, pipe is stripped in or out through a number of lubricated seals. The methods used to seal the annulus while *stripping* the pipe varies from system to system.

The *Passive RCD* is the most common system in use. Passive RCD systems utilize the buildup of annular pressure against the rubber element in order to seal the well. A Weatherford BTR RCD is shown Figure 3-5, and is an example of a passive system. As the packers or strippers are subjected to wear, they reach the point where they do not seal tight at low pressures, and must be replaced. The most common mode of failure for most passive RCD systems is leaks in the seals around the drill pipe or drill collar at low pressures (Rehm, et al., 2008).

Active RCD (Figure 3-4) systems, or rotating annular preventers, are hydraulically actuated packers. Instead of utilizing the annular pressures, the active RCD systems are actuated by hydraulic rams that force the packer element against the spherical head, where it packs off against the pipe. The active RCD is a more recent invention and is a bigger and more complex piece of kit than the passive kind. It also requires more free height above the BOP stack to install (Rehm, et al., 2008).

Figure 3-5 shows the preparation process of a Weatherford BTR RCD. The RCD is situated at the top of the BOP, on top of the riser and below the tension ring, suspended by cables. Pipe is run through the RCD as usual prior to activation. When the RCD is put into operation the pressure seals are mounted in between stands of drill pipe during a connection and stabbed in, allowing the well to be pressurized. Drill pipe is stripped in through sealing elements from that point onwards[1], which enables the driller to maintain well pressure while running drill pipe.

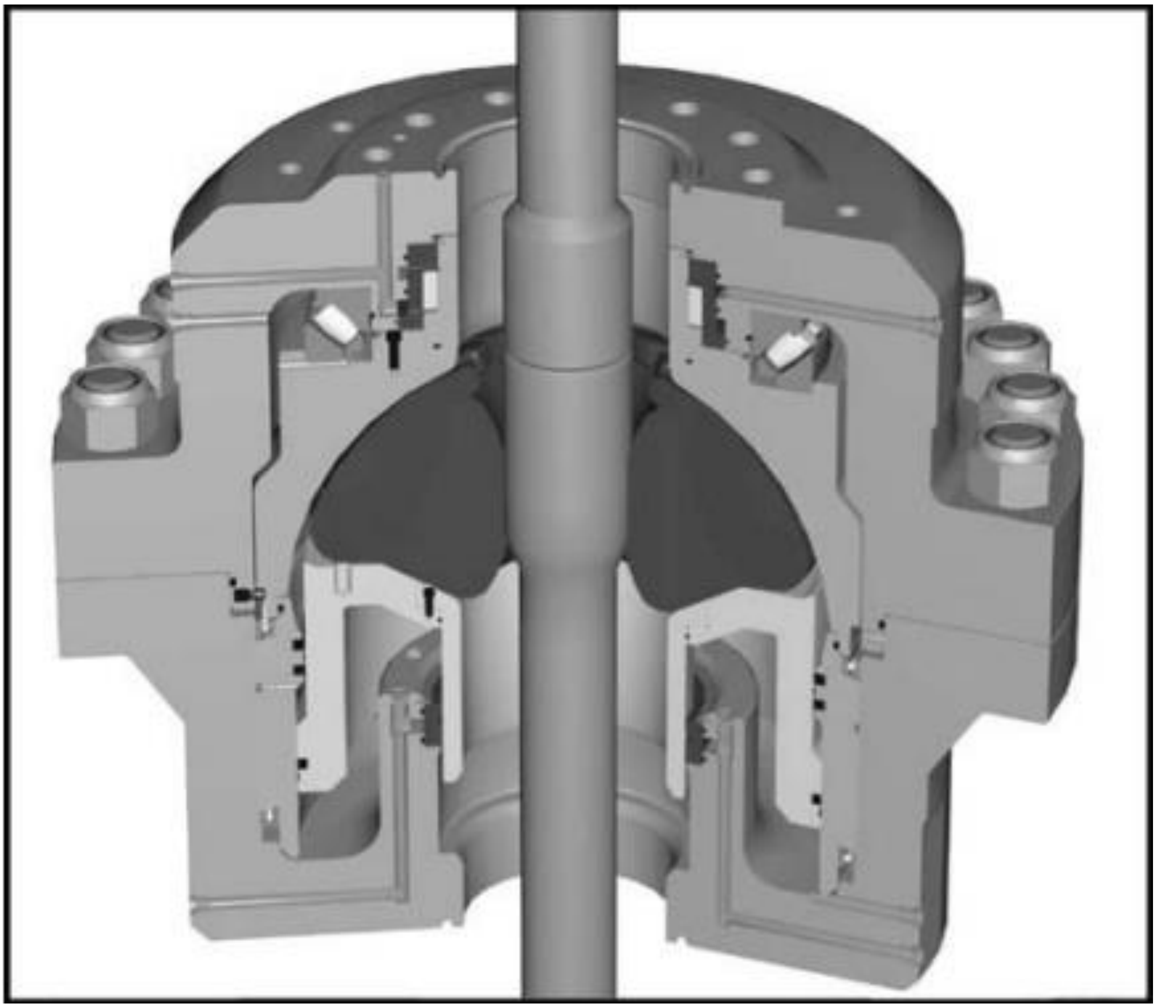

Figure 3-4: Rotating Annular Preventer - Active RCD (Rehm, et al., 2008)

Using an RCD in a closed loop system will protect rig crew, equipment and environment from typical *Health, Safety and Environment* (HSE) hazards. Gas leaks, corrosive mud systems, shallow gas hazards and unexpected kicks are examples of such hazards. In a 2010 study at the University of Texas, Austin, researchers statistically linked RCD use with reducing well control events. They found "*consistent statistical evidence, across a variety of regression models and variable specifications, that the use of RCDs decreases the incidence of blowouts*" (Jablonowski, et al., 2010).

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[1] Conversation with Henrik Sveinall, Product and Service Line Manager at Secure Drilling Systems, Weatherford, 28th of February 2014

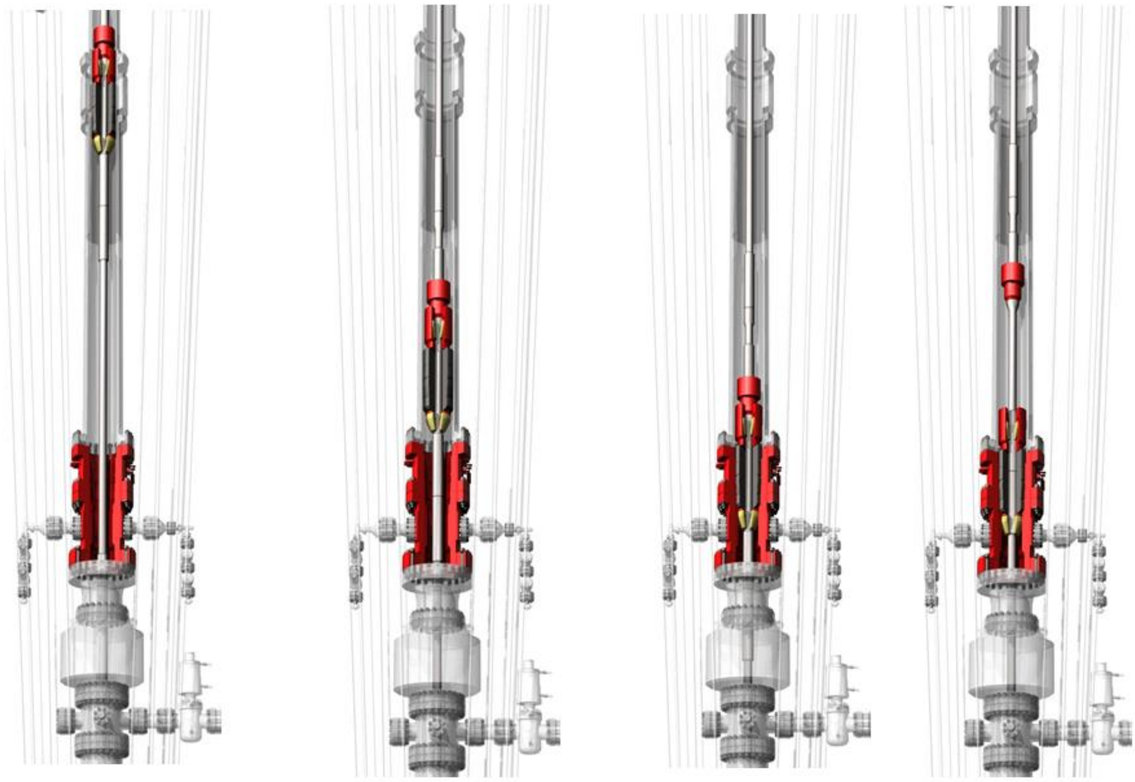


Figure 3-5: Weatherford Rotating Control Device Sealing process (Weatherford)

3.2.2 Chokes

The chokes used in MPD operations are separate from the well-control chokes. Since the MPD choke system is under constant use, it is considered prudent to have a separate, dedicated system for well control, even though the equipment is similar. Failures are extremely rare; the normal operating failure occurs because of damage to hydraulic system (Rehm, et al., 2008).

3.2.3 Non-Return Valves

The drill-pipe *Non-Return Valve* (NRV) is essential to any MPD operation. Wellbore backpressure may force drilling fluids back up the drill pipe in certain situations, particularly while making connections. The drilling fluids may contain solids (cuttings, cavings, etc.) that have the potential of damaging drill string components, such as the mud motor or MWD assembly. Returning cuttings may blow out the drill pipe, which may lead to loss of pressure control. The purpose of the NRV is to prevent flow from returning back up the drillpipe by only allowing flow in one direction (Rehm, et al., 2008).

3.2.4 Down-Hole Annular Valves

Down-hole annular valves are used to control bottom-hole pressure while tripping (commonly referred to as *surge* and *swab*), which can be a challenge using MPD. In formations with very narrow mud windows, the ECD as a result of pumping while pulling or running pipe may cause significant changes in the pressure regime, making control of bottom-hole pressure challenging. By adjusting annular valves to regulate the flow around the drill string, trips can be managed reducing the exposure to *Non-Productive Time* (NPT) issues (Rehm, et al., 2008).

3.2.5 Coriolis Flow Meters

A *Coriolis Flow Meter* is an advanced piece of equipment designed to measure the mass of fluid transported past a fixed point per unit of time. While drilling they are usually used to measure the mass rate of returning drilling fluids, which enables the driller or *Drilling Control System* (where applicable) to monitor discrepancies between flow in and flow out, and thus detect kicks (Rehm, et al., 2008).

3.2.6 Continuous Circulation System

Continuous Circulation Systems (CCS) are designed to maintain flow through the drill pipe and annulus while simultaneously making connections. The objective of using such a system is to maintain constant ECD during a time where drilling fluids would not normally circulate. These systems can be used with regular drill pipe.

While making connections, the upper tool joint is suspended in a pressurized chamber containing two pipe rams and one blind ram. Pressurized mud circulates through the CCS via two mud intakes connected directly to the chamber, as well as the flow outlet connected to the top of the drill pipe. This arrangement allows circulation to be maintained while making up and breaking connections (National Oilwell Varco).

Maintaining stable circulation while making connections helps avoid the pressure spikes that occur when circulation is reinitialized, and may thus aid in reducing fluid invasion and associated formation damage (Mæland, 2013).

3.2.7 Control System

An MPD Control System is designed to process input from sensors and flow meters and adjust output parameters according to either a hydraulic model, or mass balance (flow in vs. flow out of the well). Such a system can detect and compensate for even minute pressure changes in the well, for example caused by unexpected fluid influx, by controlling the backpressure choke manifold and pump system. The control system can be set up to maintain constant pressure at any point in the well or to follow a well program, has built-in safety alarms, manual interlocks between activities, and the ability to reverse or undo steps in the operating procedures. It is self-checking, but it can be interrupted at any stage, and the activity can be reversed by the operator (Rehm, et al., 2008).

Figure 3-6 shows a flow chart describing how a Control System is implemented in the signal chain in a rig-up, exemplified by Weatherford's Microflux Control System. Examples of read-outs from Microflux with accompanying information can be found in Figure 3-9.

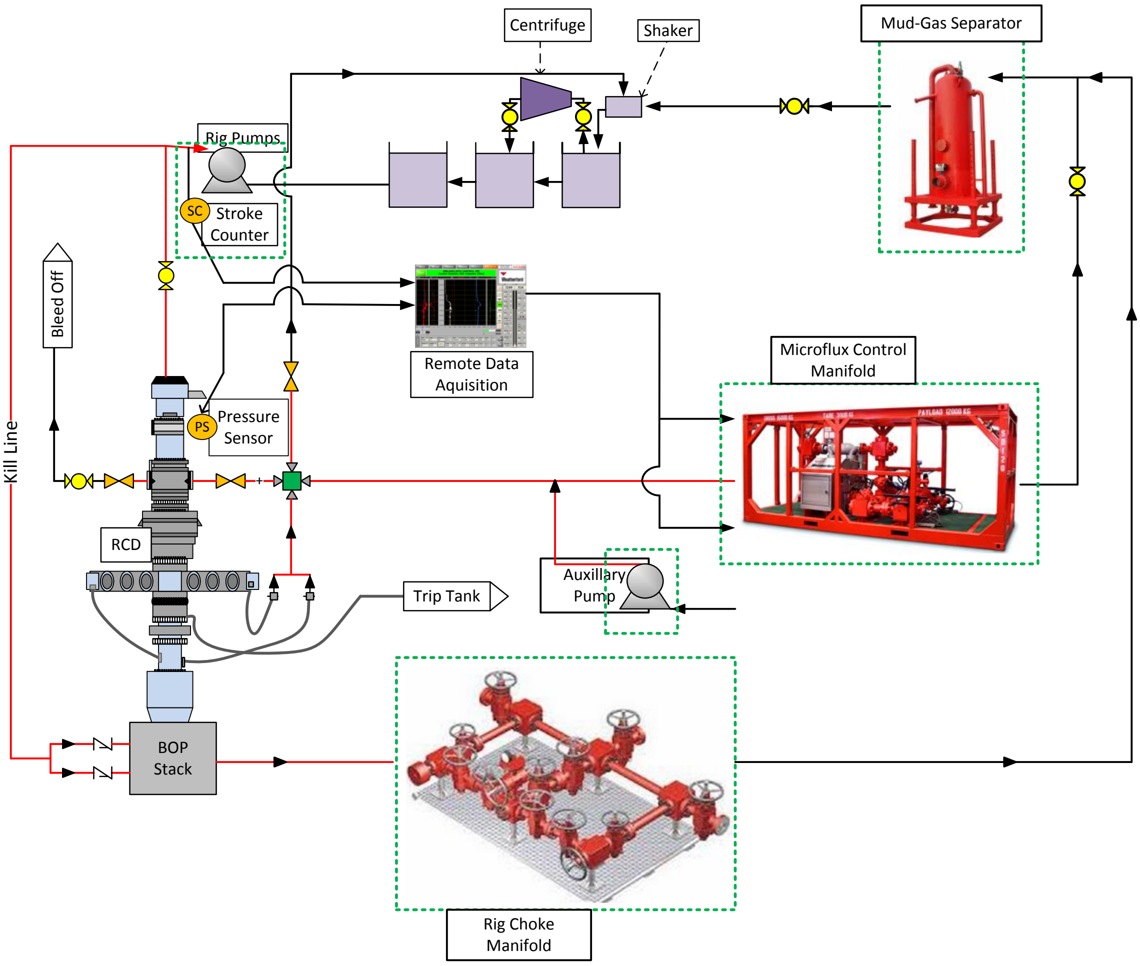


Figure 3-6: Flow schematic of a Weatherford automatic closed-loop circulating MPD system. Reproduced from (Hannegan, 2011) to accommodate the format.

3.3 Procedures and Practices

Drilling a well using MPD often means going into static underbalance, with the resulting loss of a *well barrier* as a consequence. NORSOK D-010 rev. 4 dictates the formal well barrier requirements and well control action procedures applicable when drilling under or at balance as well as completion operations, and can be found in Appendix B.

In hydrocarbon exploration and exploitation, a well barrier is defined as an "envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation or to the external environment". Furthermore, a *Well Barrier Element* (WBE) is defined as "a physical element which in itself does not prevent flow but in combination with other WBE's forms a well barrier" (Standards Norway (NORSOK), 2013).

In conventional drilling operations, the overbalanced static fluid column constitutes the most important primary barrier. Under balanced or at balance operations involves drilling with a static under balanced fluid column, thus negating the aforementioned barrier. A *passive barrier* can be understood as a static element in the well that acts as a safety barrier. Examples of passive barriers include casing, casing cement and the in-situ formation (see Figure 3-8). The term *Active barrier* encompass all well elements that have to be maintained or activated in order to function as a well barrier element. Examples include BOPs and RCDs. The *barrier envelope* consists of a combination of passive and active barriers, which must be carefully accounted for in order to maintain well control while drilling, and to regain well control if lost. A typical example of a well barrier schematic during underbalanced or at balance operations can be seen in Figure 3-8.

Figure 3-7 shows a bowtie chart describing the causes and consequences of fluid influx into the well. Shallow gas hazards, well kicks, loss of circulation and gas cut mud are all things to avoid while drilling, as cause hazardous situations. When drilling in overbalance, the choices are limited; the operator has to account for these possibilities when planning the well and the crew has to compensate immediately if an event is detected during drilling. This is usually done by shutting the *Blowout Preventer* (BOP) and circulating in heavier mud. Displacing the old mud may take as much as a day. When drilling at balance, such events are usually easily managed, as the system detects kicks early, and compensates by adjusting the back pressure. The well may be brought back under control in a few minutes. Automated control systems adjust parameters in order to bring the well back under control and the Closed Loop/RCD configuration enables the system to divert returns to avoid hazards on the drill floor. The Managed Pressure Drilling method has a perfect safety record as of 2011 (Hannegan, 2011).

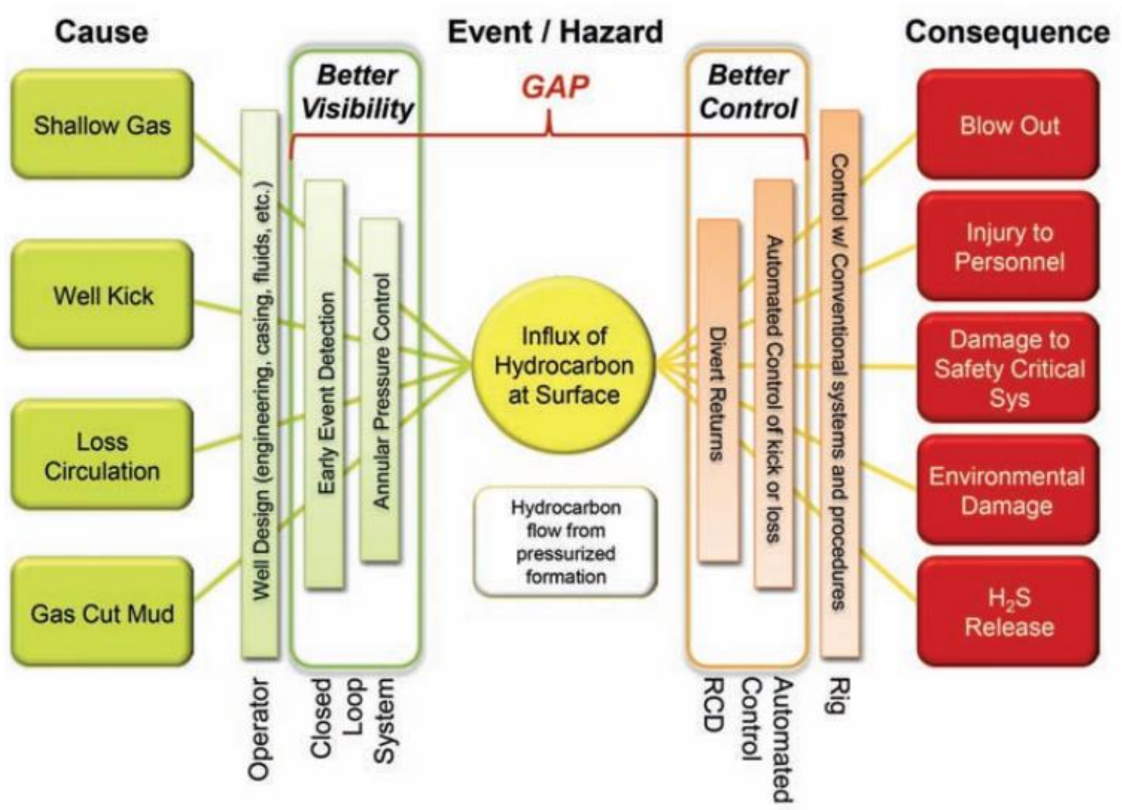
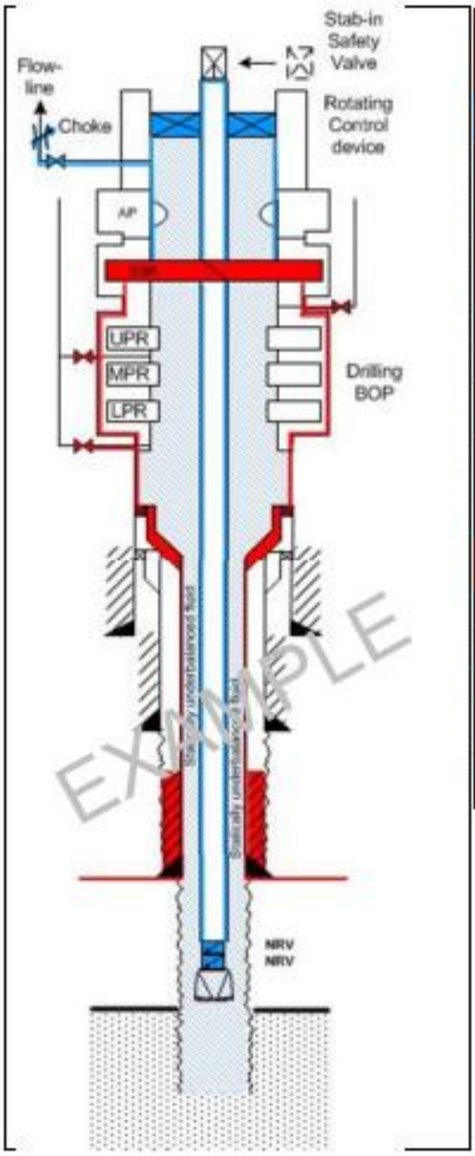


Figure 3-7: Possible causes and consequences of fluid influx (Weatherford International, 2012)



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
Statically underbalanced fluid column	54	
Casing*	2	
Wellhead*	5	
High pressure riser*	25	
Drilling BOP*	4	
Rotating control device	48	
UBD/MPD non-return valve (NRV)	50	
Drill string or completion string	3 25	
UBD/MPD choke system	53	
Secondary well barrier		
In-situ formation	51	
Casing cement	21	
Casing*	2	
Wellhead*	5	
High pressure riser*	26	
Drilling BOP*	4	

*Common WBE.

Figure 3-8: Well Barrier Schematic Example, Drilling and Tripping of String in UB Fluid (Standards Norway (NORSOK), 2013)

3.4 Value Added

3.4.1 Downhole Information

Since the well can be connected to sophisticated monitoring systems (Control System, CCS and flow meters) MPD systems enables the Operator to record significant amount of information related to the pressure regime and formations being drilled while drilling. Operational hazards can thus be detected sooner. Figure 3-9 shows a snapshot of an operation conducted using Weatherford's Microflux Control System. This is an example of the information feed provided when conducting MPD operations using the appropriate equipment. The system displays a continuous feed of flow in/flow out, measured BHP, *Stand Pipe Pressure* (SPP), ECD and choke actuation, to name but a few of the quantified parameters. This enables the driller to detect even minute changes in the pressure regime downhole in real time. These systems can be used to perform *Formation Integrity Tests* (FIT) and *Leak-Off Tests* (LOT) – which are used to determine the formation fracture gradients – with only a brief stop of operations[2]. This reduced uncertainties while drilling, and allows the driller to drill ahead through formation layers with high uncertainties pertaining to pore and fracture/collapse pressures (such as reservoirs, both virgin and depleted).

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[2] Conversation with Henrik Sveinall, Product and Service Line Manager at Secure Drilling Systems, Weatherford, 14th of March 2014

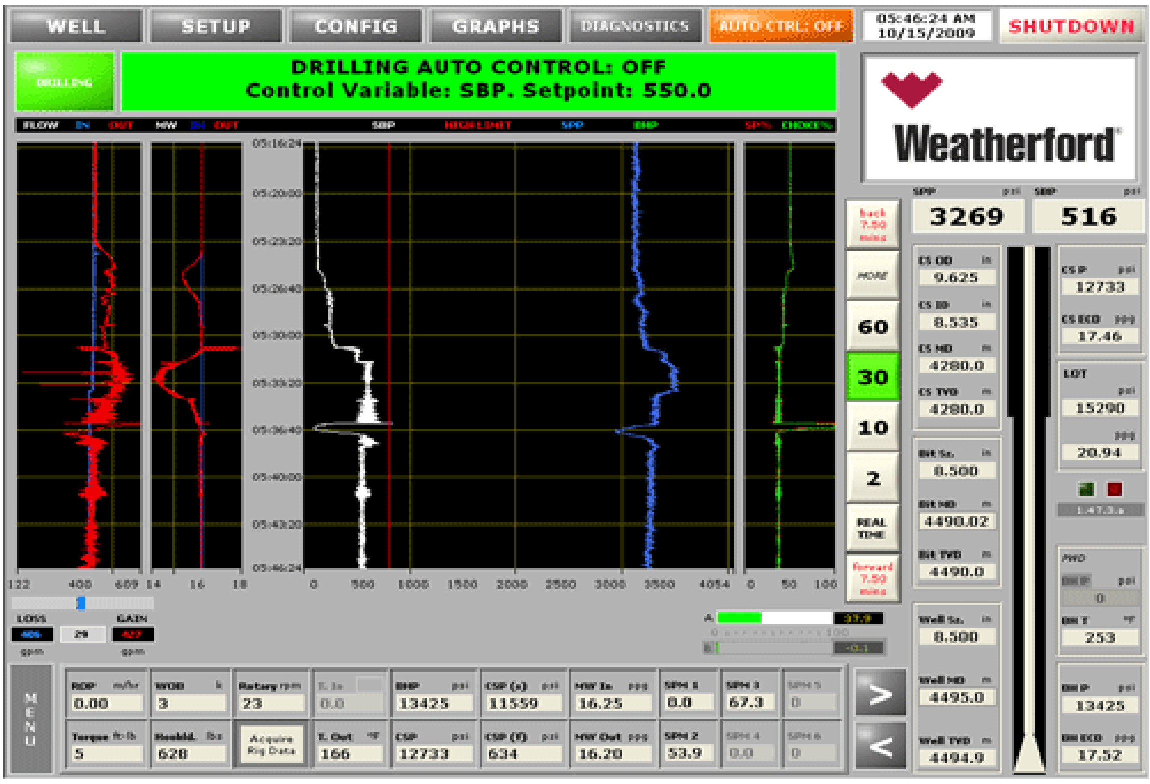

Figure 3-9: Read-out from a live MPD operation using Weatherford's Microflux Control System

3.4.2 Drillability

When drilling wells through complex formations in overbalance the *tapering (or telescope) effect* is encountered. Conventionally, the diameter of the wellbore is reduced in the section after a new casing string is set, as the bit has to fit through the casing in order to drill ahead. Each successive string thus reduces the diameter of the hole, which may eventually prevent the running of a production liner, if the wellbore diameter is too narrow. Additionally, it is often necessary to set additional casing strings, called *contingency casing* if wellbore instability problems are encountered.

MPD grants increased control over the BHP, and enables Operators to drill with smaller margins and maintain BHP between pore pressure and fracture gradient without setting the casing prematurely, enabling casing points to be set deeper. The same property enables the Operator to drill through narrow mud windows, which is prevalent in depleted and *High Pressure High Temperature* (HPHT) reservoirs, to name two examples. This has the potential to eliminate contingency casing strings and certain casing strings, allowing the Operator to drill wells that would be undrillable using conventional techniques. This is exemplified in Figure 3-10; it can be observed that the well drilled using MPD (right) has smaller casing dimensions than the one drilled using OBD (left) right up until the high pressure reservoir is penetrated.

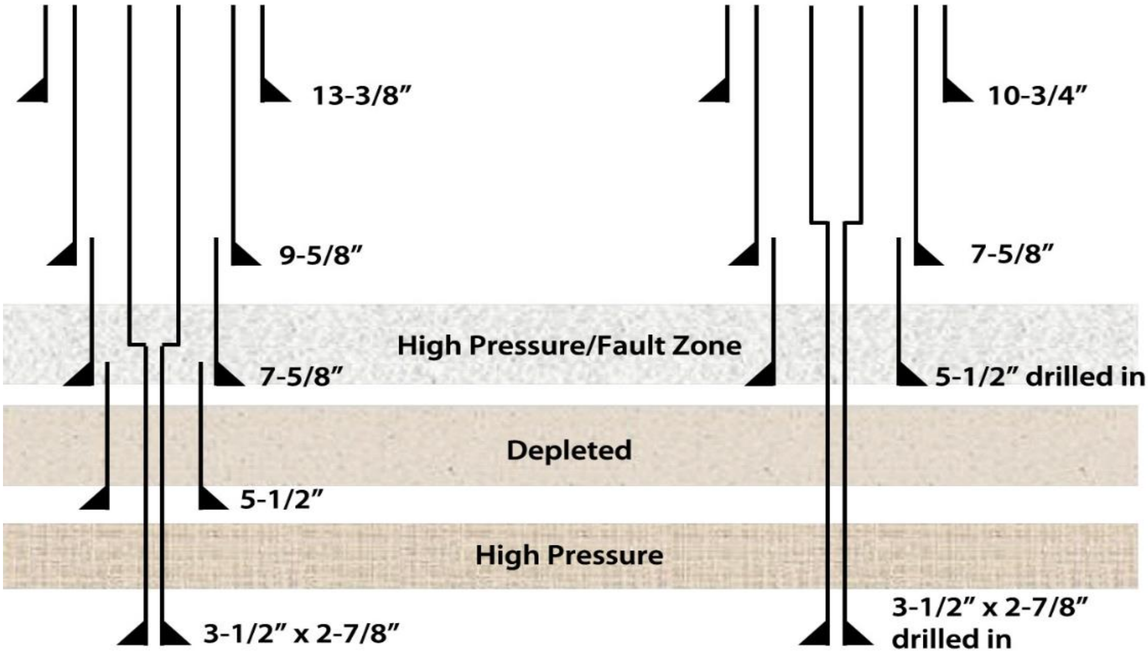

Figure 3-10: OBD casing program (left) vs. MPD casing program (right) (Montilva, et al., 2012)

3.4.3 Rate of Penetration

The *Chip Hold Down* effect is observed when the bit fractures the exposed rock face. Chip Hold Down refers to the hypothesis concerning the forces holding the cuttings that have been fractured, broken or shorn off by the drill bit in place. In theory, this prevents the cuttings from being separated from the formation and circulated out of the hole with the rest of the solids. This effect can be described physically as a combination of suction between the chip and formation and pressure differential between the formation and the rockface at the bottom of the wellbore (pressure exerted on the chip by the mud column). A reduced pressure differential has the potential to reduce the forces acting on the cuttings. Thus, MPD has the potential to improve the transport of cuttings away from the rock face. This may in turn improve the ROP as the bit can cut through new rock rather than pulverizing old cuttings. An added benefit is that it reduces the occurrence rate of phenomena like *bit balling*, and improves bit life (Showers, et al., 2013).

3.4.4 Stuck Pipe

In drilling operations, the drill string is considered *stuck* if it cannot be freed from the wellbore without damaging string or string components, or by exceeding the rig's maximum *hook load*[3]. *Differential sticking* is a common problem while drilling wells in overbalance and is, for most drilling organizations, the greatest drilling problem worldwide in terms of time and financial cost (Rafique, 2008). Differential Sticking typically occurs when high contact forces caused by low reservoir pressures, high well bore pressures, or both, are exerted over a sufficiently large area of the drill string, as shown in Figure 3-11. A consequence of using MPD techniques is a reduction in differential pressures, and may thus reduce the occurrence of differential sticking issues, or eliminate differential sticking altogether.

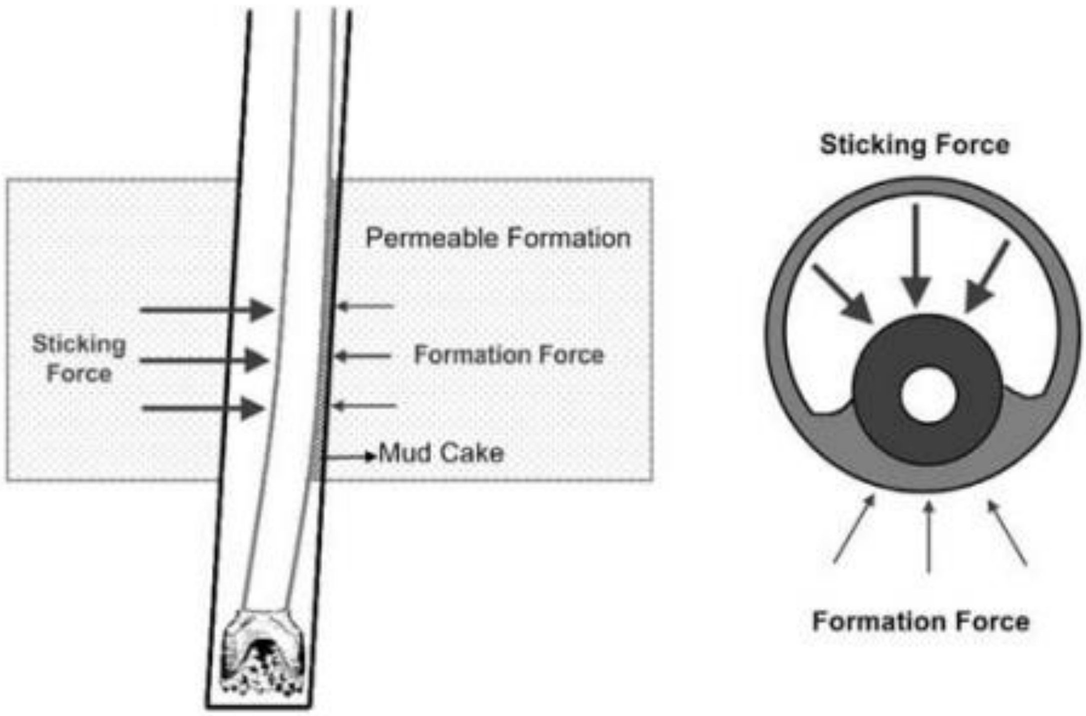

Figure 3-11: Differential Sticking (Rehm, et al., 2008)

3.4.5 Near-Wellbore Conditions

Porous formations contain certain amounts of clay. When exposed to water with high *activity*, clay particles tend to swell. Water activity, a_w, is a way of quantifying the intensity of which water associates with certain non-aqueous constituents and solids (Zumdahl, 2009). In the case of distilled water, $a_w = 1$. When diluted, the activity decreases. Thus saline, for example, has a lower chemical activity than pure distilled water and thus has a lower affinity for bonding with clay molecules.

[3] **Petrowiki.** Stuck Pipe. [Online] [Cited: March 5, 2014.] http://petrowiki.spe.org/Stuck_pipe.

Clay swelling may occur when drilling in overbalance due to mud filtrate invasion if the mud's salt content is insufficient. Clay swelling causes the permeability of the exposed rock to drop significantly by blocking the pore throats in the rock. Blockage of pore throats may also be caused by solid particles that have been forced into the rock's pore system. In any case, both can be correlated to the magnitude of overbalance in the well. This undesired effect is referred to as *wellbore damage*, and is usually quantified as a *skin factor*[4]. The greater positive skin, the higher the *drawdown*[5] has to be in order to achieve the same production rate as a comparable case with no skin or negative skin. This can be seen juxtaposed to the *Ideal Productivity Index* (PI_{IDEAL}), which is commonly quantified by Eq. 3-4 (Dake, 2001):

$$\boldsymbol{PI_{IDEAL} = \frac{q}{p_i - p_{wf} - \Delta p_{skin}}} \qquad \textbf{Eq. 3-4}$$

where

$\boldsymbol{p_i}$	=	Initial Pressure in the reservoir
$\boldsymbol{p_{wf}}$	=	The pressure in the flowing well
$\boldsymbol{\Delta p_{skin}}$	=	Pressure drop as a result of formation damage
$\boldsymbol{q}$	=	Production Rate

As can be seen in Eq. 3-4, an increase in $\boldsymbol{\Delta p_{skin}}$ will reduce the producing flow rate of a well at constant PI and drawdown ($p_i - p_{wf}$). Due to limitations in flow metering in topside facilities, this effect is typically best observed over time, as the production of a low-productivity well will decrease earlier than a comparable high-productivity well, maintaining plateau for a shorter period of time. In short, less skin yields greater producing flow rate potential and higher ultimate recovery (Dake, 2001). Attempts to mitigate wellbore damage induced while drilling is usually done post-completion by the means of well stimulation efforts (e.g. acidizing), or as well intervention efforts executed some time during the lifespan of the well. Such efforts are time consuming, especially in subsea completed wells, and carry significant additional expenses (Naterstad, 2013).

Any reduction in the degree of overbalance while drilling may have a positive effect on inflow performance around the well by reducing the impact of drilling fluids and drilling fluid solids on the surrounding formation. Some reservoir benefits may thus be attained using MPD techniques (Ostroot, et al., 2007). Residual reservoir damage is still likely to reduce production potential compared to similar wells drilled using

[4] S=0 indicates no damage, S>0 indicates reduced inflow performance, S<0 indicates improved inflow performance.

[5] Drawdown: Difference between flowing well pressure and formation pore pressure

Underbalanced Drilling (UBO). Case studies imply that production improvements using MPD methods can be as high as twice that of a comparable well drilled using OBD, yielding additional 5% net revenue (Ostroot, et al., 2007).

3.4.6 Mud properties

Basic to MPD techniques is the ability to apply backpressure to the wellbore system. As previously mentioned, this has some implications to the properties of the drilling fluids; most importantly that of lower specific mud weight. Using a mud system with lower specific mud weight allows the Operator to use less solids mixed with the drilling fluids while drilling the well.

A common challenge when drilling slanted wells is that of *avalanching*. Avalanching can be understood as the collapse of a bed of solids that has settled out of suspension, which may congest the wellbore and cause stuck pipe incidents when the drill string is pulled out of the wellbore (Skalle, 2012). This phenomenon is prevalent in medium angle well sections (~30^o to ~65^o). Figure 3-12 illustrates the forces acting on the solids both while stationary and while circulating. The slip velocity of the solids is determined in part by the shape and density of the cuttings, and in part by the gel effect, which is a property of non-Newtonian fluids (K&M Technologies, 2011). This will be explained in further detail later in the thesis.

When applying MPD techniques, the risk of becoming stuck while drilling or tripping is reduced due to less amounts of settling solids mixed into the drilling fluids, and the associated reduction in occurrence of avalanching. In addition, there is some potential for reduced formation damage, since there are less solids available to block the pores in the reservoir rocks.

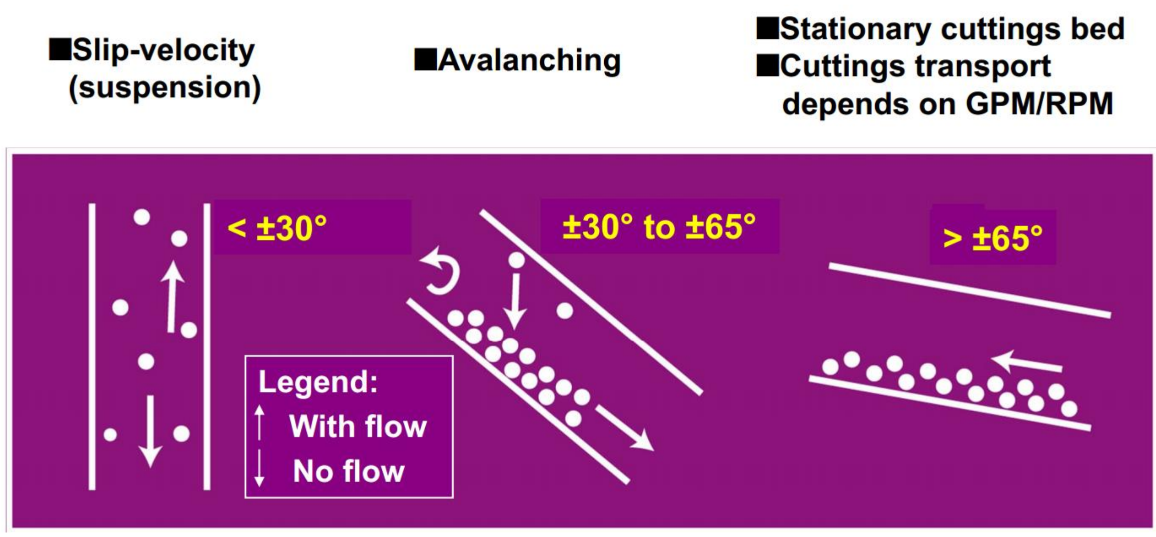

Figure 3-12: Cuttings behavior demonstration (K&M Technologies, 2011)

3.5 Limitations

3.5.1 Expenditures

While MPD operations carry certain benefits, they also carry additional expenditures. MPD is not a part of the average rigs' arsenal; the equipment has to be installed when required. Rigging up MPD equipment may take a few days; normal rig operations have to be halted in the meantime. In addition, this kind of service is usually provided by Service Companies, not by the *Contractor* (which operates the rig and employs and trains the rig crew), meaning that specially trained crew has to be hired and transported to the rig. Considering the rig rates shown in Table 12 in Appendix A, the expenditures associated with rigging up and utilizing MPD equipment and techniques may run in the millions of USD.

3.5.2 Floaters – Heave during connections

Between stands, during make-up and break-outs of connections, the drill string is suspended in slips in the rotary table. When drilling from floaters, the drill string will move up and down with the wave motion, along with the heave of the *Mobile Offshore Drilling Unit* (MODU). Pipe movement induces transient pressure in the wellbore. If the transient pressure increases the BHP, it is referred to as a *pressure surge*; if transient pressure reduces the BHP, it is referred to as a *pressure swab* (Rehm, et al., 2008). This occurs when running and pulling pipe respectively. Surge and swab may cause unintended fluid influx, or lost circulation events (Rasmussen, et al., 2007).

The magnitude of wave-induced surge and swab pressure is determined by several parameters: fluid properties, fluid gelling properties, geometry of the wellbore and pipe, velocity of the pipe, compressibility of the drilling fluid and wellbore, fluid inertia, pipe distance of the bottom of the hole, drill bit and nozzle size, and pipe elasticity and acceleration of the pipe (Rehm, et al., 2008).

Maintaining a stable BHP under these conditions requires the models and control systems to account for all of the parameters mentioned above, and more. The pressure fluctuations must be compensated for by actuation of the topside choke, which requires precise prediction of magnitude and frequency of said fluctuations.

3.6 Summary

Field applications imply that the various MPD techniques have uses beyond that of navigating through narrow mud windows. There is a significant cost savings potential as, which is a result of reduced uncertainties and time saved performing certain activities (Nauduri, et al., 2009):

- Being able to more accurately control the pore pressure from the surface may in many instances eliminate the need to circulate in new mud in order to change the BHP
- Extending casing points may allow the Operator to eliminate casing strings, saving time tripping, and setting/cementing casing
- Improved kick/loss detection and mitigation means less time spent on well control events. Also, kicks occur less frequently due to reduced differential pressures
- Reduced differential pressures may also reduce the occurrence of certain stuck pipe incidents

A disadvantage of using this method is that the back pressure is applied evenly over the entire interval; increasing the BHP by applying additional BP will yield an equivalent increase in uphole wellbore pressure. The riser pressure rating will restrict the ability to safely apply backpressure, however. Table 3 shows a summary of some potential advantages of utilizing CBHP MPD methods, while Table 4 shows a summary of some potential disadvantages.

Table 3: MPD Summary Benefits

Property	Potential Benefit	Result	Comment	Cost	HSE
Closed Loop Circuit	Changes in flow out of the well may be detected almost immediately	Reduces uncertainties	Kicks and losses detected in a matter of minutes		
	Contain formation gas and downhole liquids	Improve HSE	Less chance of hazardous fluids spilling onto rig floor		
	Perform FIT & LOT tests while drilling	Increased knowledge about pressure regimes	Less chance of encountering hazardous situations		
Apply backpressure	Adjust wellbore pressure in a matter of minutes	Reduce time spent on well control events, improve HSE	No need to circulate in new mud		
		Smaller margins	Drill narrow mud windows		
Continuous Circulation System	Avoid pressure surges when starting circulation, maintain stable borehole conditions when making connections	Improve HSE, reduce likelihood of losing well	Improved borehole quality, avoid formation squeeze, avoid lost circulation		
Drilling closer to balanced conditions (lower pressure differential between borehole and formation)	Increase ROP	Reduce rig expenditures	Due to reduced "Chip Hold Down" forces		
	Increase bit life	Reduce bit expenditures and time spent tripping string out of hole	Less WOB, less chance of "bit balling" occurring, less wear on bit		
	Minimize fluid losses	Reduce mud expenditures	Less likely to exceed fracture pressure during drilling		
	Reduce occurrence of loss/kick events	Improve safety and time spent managing well control events	Due to greater control of pressure regime and lower margins		
	Extend casing points, set casings deeper	Reduced number of casing strings in well			
	Reduce formation damage	Improve productivity, reduce time spent and/or improve efficiency of cleanup operations	A result of reduced formation water and particle invasion		
	Reduce occurrence of differential sticking issues	Reduce time spent working string, fishing, sidetracking, and cost of tools left downhole	Differential forces acting on the string is reduced		

Table 4: MPD Summary Disadvantages

Property	Potential Disadvantages	Result	Comment	Cost	HSE
Additional Equipment Needed	Additional rig-up time required	Lost time	Drilling has to be halted while equipment is installed		
	More deck space required	May cause need for additional supplies to be brought in or bigger rigs	May take up space otherwise used for storage of consumables		
	Crew needs training in using equipment	Time spent training crew	May cause HSE concerns if training is insufficient		
Increased complexity of operations	Operations require careful planning	More time spent preparing for operations			
Apply Backpressure	Ability to apply backpressure limited by riser	Applying sufficient backpressure may be challenging in certain situations	Operations has to be halted, and MW increased		
	Backpressure is applied evenly along the wellbore	Increasing the BHP to manage well control events at the bottom of the well may instigate lost circulation events uphole			

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4 Casing & Liner Drilling

4.1 Techniques and Enabling Technologies

The terms *Casing Drilling* (CD) and *Liner Drilling* (LD) refer to the practices of installing regular oil field tubulars while drilling. While drilling, drilling fluid is circulated through the inside of the casing or inner string and up the annulus between the casing and well bore. The original purpose of developing these methods was to eliminate NPT associated with tripping and running of casing and liner. The wells are drilled with casing replacing drill pipe in the drill string (or replacing the lower sections of drill pipe in the case of LD), and are drilled and cased at the same time. CD/LD is often used to drill through depleted reservoirs, poorly consolidated formations, and weak zones preceding high-pressure zones where loss of circulation is common, or there is a high probability of becoming stuck. It may be used to drill entire wells, or individual intervals (Warren, et al., 2004). CD/LD systems come in different configurations, mainly systems with *non-retrievable* and *retrievable Bottom-Hole Assemblies* (BHA), an overview of which can be found in Table 5.

Non-retrievable BHA systems

Most of the wells drilled using casing or liner is drilled using systems with a non-retrievable BHA, as they are both cheap and efficient. These systems have bits fixed directly at the bottom of the drill string along with a float collar and the assembly is run down hole and cemented in place without a BHA. In some cases, regular drill bits have simply been welded directly onto the casing string and run downhole in order to manage trouble zones (Eeck-Olsen, 2012). None of the string components are retrieved to the surface, and logging is performed using wireline-mounted tools. The bits are often drillable, so that it is possible to drill new sections through the existing casing (Strickler, et al., 2005).

Non-retrievable systems require the top drive to rotate the string in order to deliver power to the bit. If conditions indicate that the top drive may be unable to deliver the power required to the bit in order to achieve a sufficient ROP, a single-run *Positive Displacement Mud Motor* (PDM) may be included in the string, which is cemented downhole along with the bit. A caveat with using PDMs is that it requires a certain flow rate in order to stay within optimal parameters to avoid drilling problems such as stick/slip and bit whirl. Also, PDMs are not drillable, so the advantage of being able to drill through the shoe and bit is negated. Due to the cost of leaving such tools downhole, Non-Retrievable systems typically have no trajectory control. Figure 4-1 shows simplified, but typical CD and LD systems with non-retrievable BHAs.

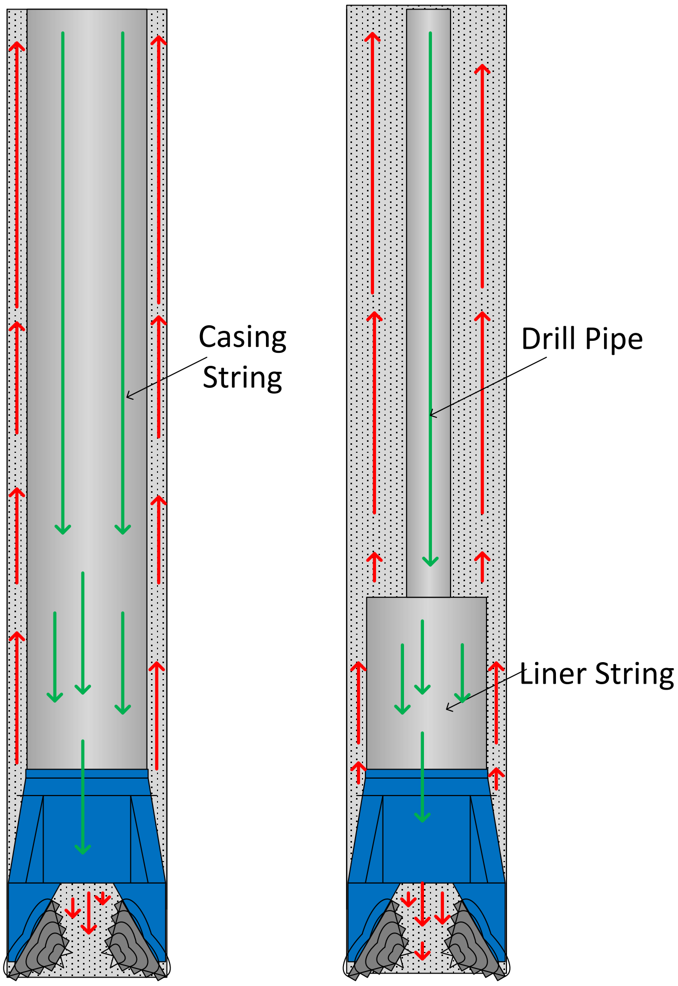


Figure 4-1: Casing Drilling and Liner Drilling technology concepts, non-retrievable BHAs depicted.

Retrievable BHA systems

Components commonly included in directional drilling BHAs such as MWD/LWD and *Rotary Steerable Systems* (RSS) represent a significant expenditure if lost. Due to the cost incurred by leaving such tools downhole, systems with retrievable BHAs is the only practical solution for drilling directional wells using CD/LD (Warren, et al., 2004).

The configuration of Retrievable CD/LD systems differ from manufacturer to manufacturer. They all have in common that a small diameter pilot string carrying the BHA is run as an extension of the casing, providing trajectory control and logging capabilities (if applicable). An *underreamer* (see Appendix D for supplementary information) is mounted at the end of the casing/liner string to expand the hole in order to run the liner. Some companies, such as Tesco, commonly use a wireline retrievable system to retrieve the pilot string. Others, like Baker Hughes, run an inner string through the entire casing/liner string. The latter may be considered more dependable, as it may be easier to retrieve the pilot string if it becomes stuck[6], but it also carries additional weight, which is disadvantageous to wellbore-string friction and torque[7], especially in deviated wells. Common to both technologies is the use of a *Drill-lock Assembly* (DLA), shown in Figure 4-2. A DLA is a pilot-string mounted tool that is used to maintain a pressure-tight seal between the liner or casing string and pilot string BHA. Before retrieving the BHA, the locks are actuated by a ball-drop and released, freeing up the pilot string to be pulled out of the wellbore (Warren, et al., 2005). This particular tool is designed by Tesco for use with wireline-retrievable BHA-systems, thus the design may differ when used with an inner string.

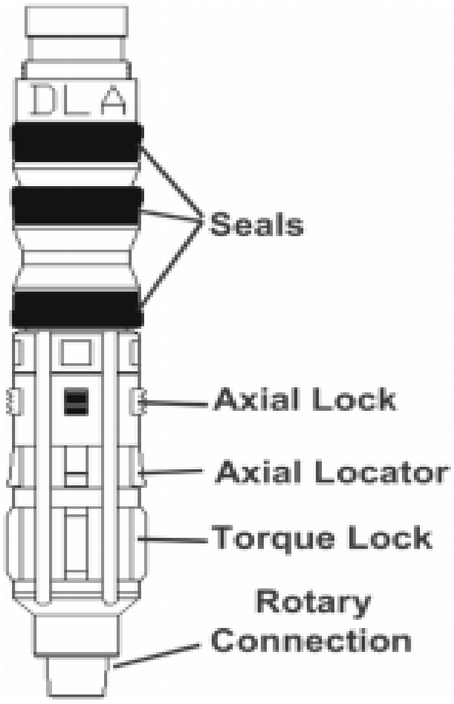
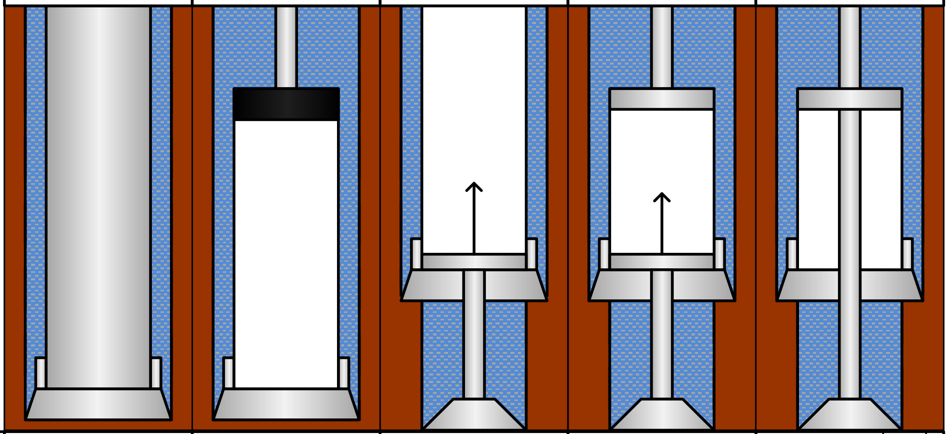


Figure 4-2: Drill-lock Assembly (Warren, et al., 2005)

[6] Wireline have a limited tensile strength, limiting the pulling capacity (Naterstad, 2013)
[7] Conversation with Jafar Abdollahi, 25th of April 2014

Table 5: An illustration of the different Casing/Liner Drilling systems

	Non-Retrievable Systems		Retrievable Systems		
	Surface Rotation Required (Top Drive)		Surface Rotation (Top Drive) + Mud Motor		
	Casing	Liner	Casing	Liner	Liner
					
Means of retrieving BHA	N/A	N/A	Wireline or Drill Pipe	Wireline or Drill Pipe	Inner String (BHA) detachable and retrievable
Directional capabilities	N/A		Bent Housing and RSS on pilot string		
Formation Evaluation	Wireline Only		Full BHA capabilities on pilot string: RSS, Mud Motors, MWD, LWD		

4.2 Procedures and Practices

When installing a liner, it is typically set with an overlap of 100m from the start of the liner to the end of the last casing string[8] in order to ensure a god seal. Liner centralizers are run along the string in order to maintain annular clearance along the liner. Insufficient clearance between the borehole wall and liner may have consequences on the integrity of the following cementing job.

Minor modifications to the rig may be necessary in order to drill sections using liner or casing. The *top drive* especially may be a point of concern; casing or liner strings requires more power to rotate due to the increased diameter, and may thus require installation of a top drive able to deliver more power (Warren, et al., 2004).

The pressure regime in fluid bearing zones may be unpredictable, and so to avoid fluid losses or influx, it is standard practice to set a casing point a few meters prior to penetrating the reservoir (see Figure 4-3). The mud weight must be chosen so that the ECD falls within both the upper and the lower boundary. As seen in Figure 4-3, this may cause the ECD to exceed the fracture pressure limit of the reservoir. Drilling with liner or casing allows the driller to penetrate the reservoir without having to set the casing above the producing zone[9]. A significant benefit of being able to safely penetrate the reservoir without setting a casing point right above it is that it reduces the uncertainties pertaining to the pore pressure regime in the reservoir. This is exemplified in Figure 4-4; the previous casing point is set inside the reservoir.

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[8] Conversation with Jafar Abdollahi, 31st of January, 2014
[9] Conversation with Jafar Abdollahi, 16th of May, 2014

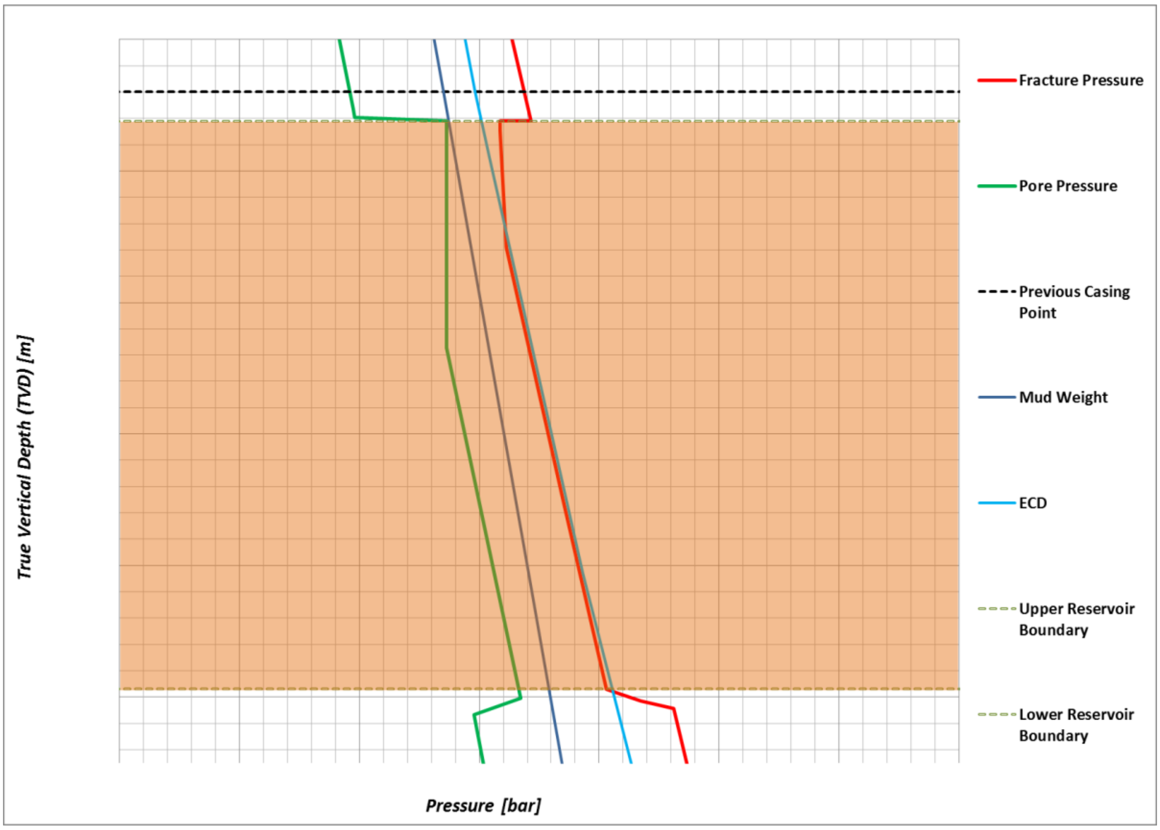


Figure 4-3: Previous interval drilled conventionally – Previous casing point set above reservoir

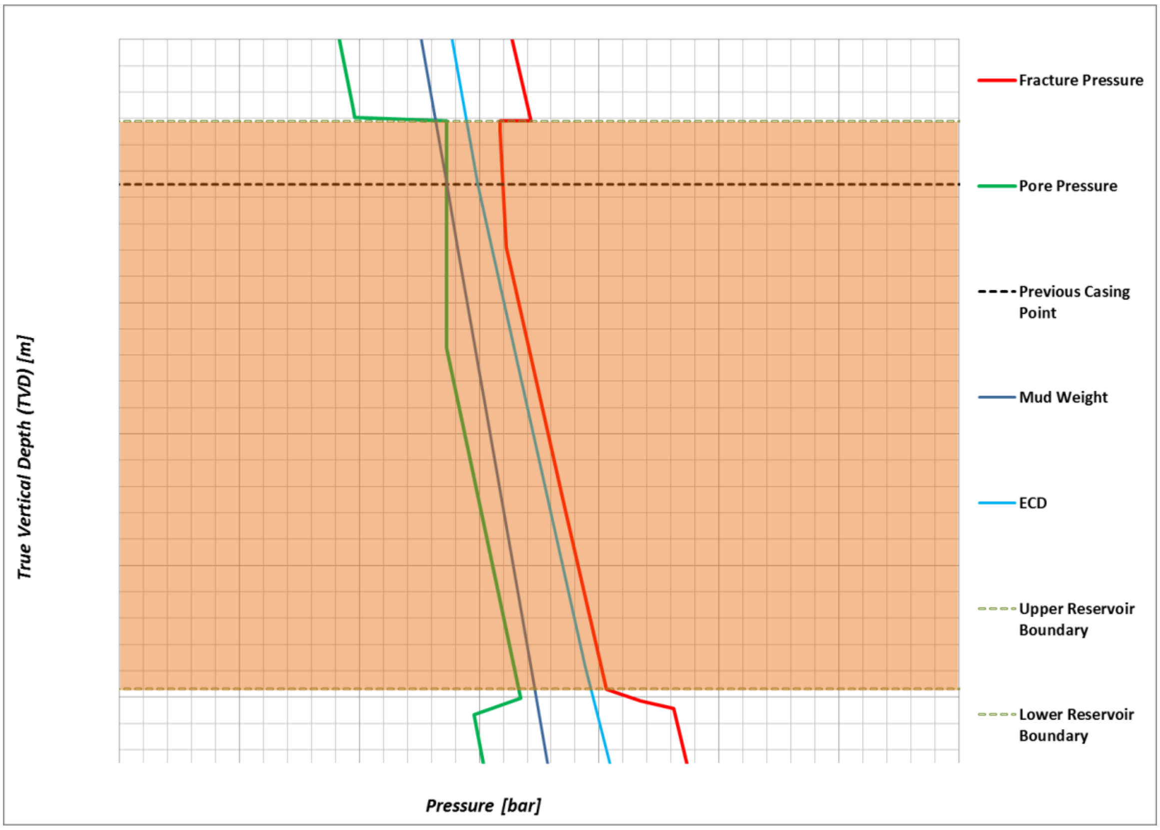


Figure 4-4: Previous interval drilled with CD/LD – Previous casing point set in reservoir

4.3 Benefits

4.3.1 Efficiency

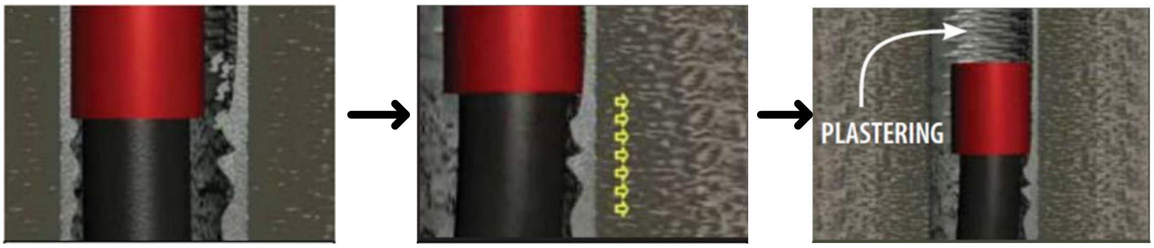
Central to the CD/LD concept is the fact that the string (and thus the casing/liner) is always at the bottom during drilling, and every foot drilled is a foot gained in well length. If the string becomes stuck, and attempts to release it are unsuccessful, the inner string is pulled out (if the BHA is of the retrievable kind) before the casing/liner is cemented in place. Once the cement is set, the driller may continue drilling ahead according to the drilling program, though it may be necessary to use expandable tubulars or contingencies in order to reach TD. Using CD/LD will thus reduce the occurrence of incidents that may lead to the loss of the wellbore, and time consuming sidetracks.

The same property reduces the amount of time spent tripping; when drilling with a conventional drill string, the drill string has to be retrieved before the liner string is run downhole and cemented in place. The time saved tripping increases with the length of the well. Flat Time will increase somewhat where retrievable BHAs are used, as the inner string has to be pulled out of the hole before cementing the liner is place (Carlsen, et al., 2000).

Drilling occurs in an inherently harsh environment; during drilling, a conventional drill string has a tendency to move erratically and vibrate violently. This occurs in part due to the freedom of motion inherent to running a small pipe in a big hole, and in part due to elasticity of the drill string which may cause stick/slip and rock removal-related vibrations. As was mentioned in Chapter 2.2, equipment related trips are a source of Flat Time, and equipment related damage often occurs as a direct result of BHA vibrations (Mancini, et al., 2009). Liner and casing string are stiffer than conventional drill pipe, which allows the drill string to move in a smooth continuous motion while drilling. This reduces shocks, string vibrations and *stick slip*, and may thus improve the *Mean Time Between Failure* (MTBF) and reduce the associated equipment related trips and Flat Time.

4.3.2 Smear Effect

Chapter 3.4.5 describes how the permeability of the near-wellbore formation may be negatively affected by water invasion. Since one of the consequences of using CD/LD is a smaller annular flow area, the flow velocities are higher than conventionally drilled wells at comparable flow. As will be explained later on, this may lead to significantly higher AFP and a higher pressure differential if the flow rates are not carefully controlled. It may thus be natural to assume that CD/LD may lead to greater formation damage. Findings indicate that the opposite may be true in the case of CD/LD; that using such techniques has a positive effect on formation damage (Karimi, et al., 2011). The *smear effect*, or *plastering effect,* is an observed phenomenon believed to affect boreholes being drilled with a narrow annular clearing. It is believed that the wellbore wall is continuously troweled by the rotating casing or liner, and that cuttings are crushed and smeared into fractures and pore spaces in the borehole wall. This is illustrated in Figure 4-6. This may under certain conditions create a high quality impermeable filter cake, and may serve to improve the stability of the wellbore by strengthening the formation. The smear effect is also believed to cure lost circulation scenarios and reduce formation damage (Moellendick, et al., 2011).



A B C

Figure 4-5: The casing is being forced against the wellbore while drilling in A. B shows the mud being forced into the formation along with pulverized cuttings, while C illustrates how filter cake and cuttings are plastered against the wellbore wall, sealing the porous formation (Karimi, et al., 2011).

This effect is not sufficiently documented, but circumstantial evidence such as a reduction in cuttings returns when drilling with liner or casing suggests there is some truth to the hypothesis. It is thought that the combined forces of high annular velocity and pipe rotation creates an environment especially suitable for grinding and smearing of cuttings into the formation, and that "The Plastering Effect" enables stress caging to occur when the cuttings seal the fractures in the near wellbore formation wall. Additional evidence for this effect has been found by taking sidewall core samples that confirms that cuttings and filter cake has been pushed into the formation (Moellendick, et al., 2011).

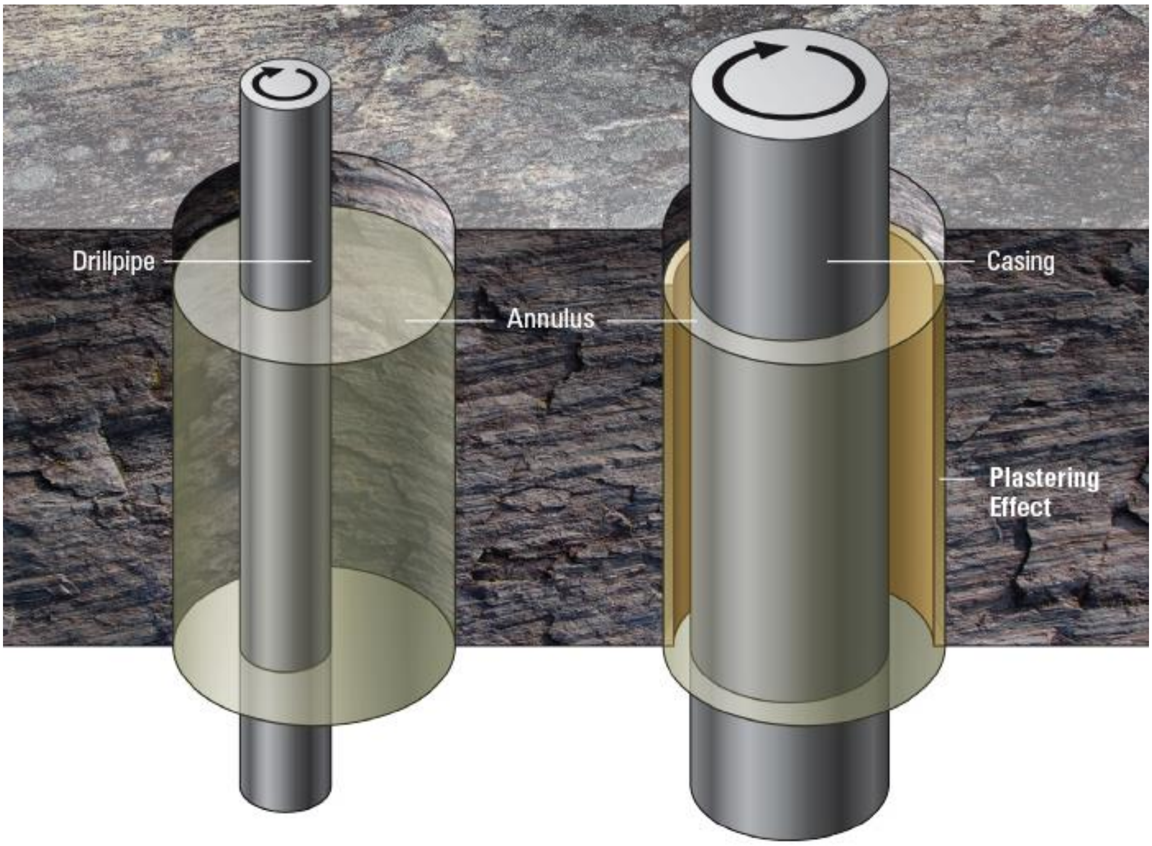


Figure 4-6: The rotating casing string smears cuttings into the formation, "plastering" the wellbore (Schlumberger LTD.)

4.3.3 Wellbore Stability

Casing and liner drilling offer several unique aspects that may help mitigate wellbore stability issues. Since the casing/liner is always at TD during drilling, the amount of time spent tripping is reduced, and every foot drilled is a foot gained in well length. It is generally accepted that most wellbore stability and stuck pipe issues arise during tripping.

One of the most common issues while drilling is swab and surge pressure fluctuations which can lead to well control incidents or lost circulation. The inability to circulate the well from the bottom while tripping is another challenge, and can result in cuttings settlement or stuck pipe while tripping in the BHA. Elimination of tripping leaves no chance to instigate such issues. Moreover, by definition, there would be no need for wash and ream procedures after reaching TD and before running casing (Moellendick, et al., 2011).

Another beneficial aspect of CD/LD is that the openhole time is significantly reduced, and there is no mechanical load on weak formations after the casing/liner has been cemented in place. As the wellbore is cased off, reactive formations spend less time exposed to aqueous fluids, which is another facet of the technology that aids in improving wellbore stability; less time exposed to reactive shales leads to less issues related to formation squeeze (Dokhani, et al., 2013).

The inherent stiffness of the casing/liner string means that the string moves in a smooth, continuous motion while drilling compared to a string made up of conventional drill pipe. The result is a less tortuous wellbore, with a reduced risk of key-seating and stuck pipe incidents occurring as a result of mechanical friction (Pritchard, 2010). The drill pipe and underreamer configuration of retrievable systems add to this effect, generating a wellbore with a more circular profile. A geometric comparison may be seen in Figure 4-7 (Moellendick, et al., 2011).

The smear effect discussed in the previous chapter has another interesting property; that of *stress caging*. When the solid particles are troweled into the formation, they may help strengthening the porous formation around the wellbore, and small fissures and fractures may be sealed. This has the potential to increase the fracture strength of the formation, increasing wellbore stability (Moellendick, et al., 2011).

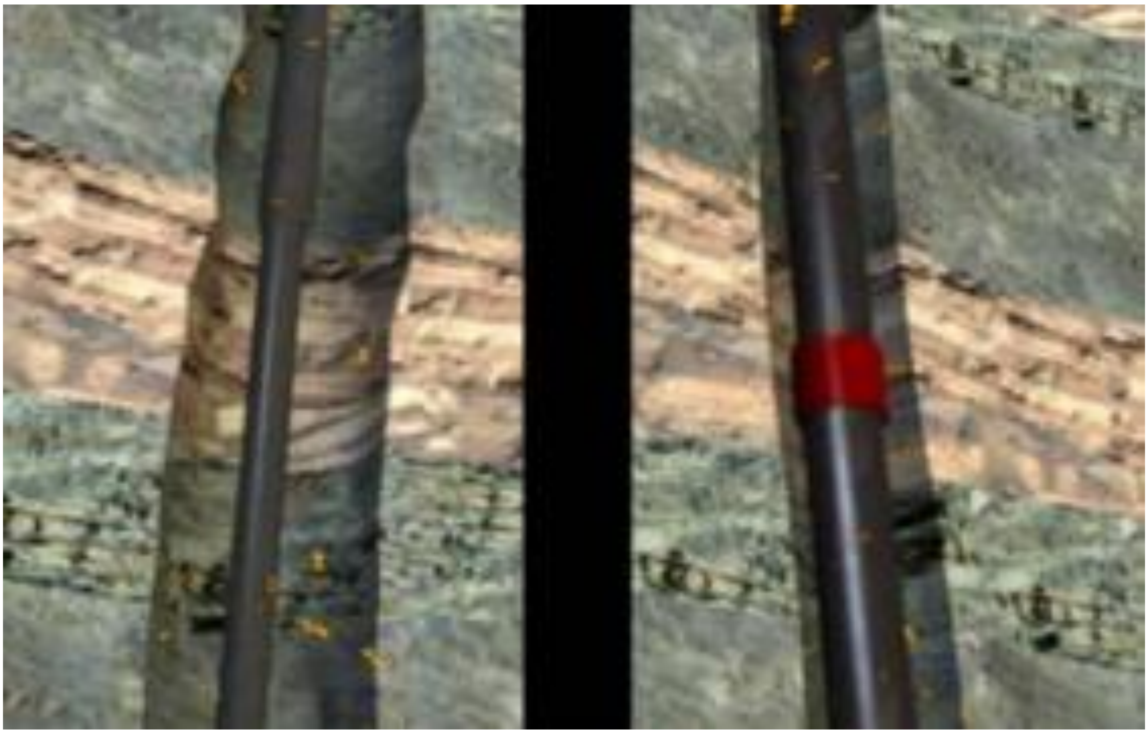


Figure 4-7: Drilling with Casing/Liner (right) creates gauged wells (Moellendick, et al., 2011)

4.3.4 Wellbore Cleaning

Removing cuttings from a well is mainly a matter of maintaining sufficiently high flow rates to counteract the vertical slipping of cuttings in vertical sections, and to counteract settling of solids in horizontal sections (Skalle, 2012).

In vertical sections, the flow rate and fluid parameters are the most important parameters affecting wellbore cleaning. Maintaining a high enough flow rate ensures that the axial fluid velocity is greater than the slip velocity of the solids. Slip velocity is a measure of the minimum velocity needed to lift the solid particle upwards, and is determined by the geometry of the solids and the fluid properties. In short, the goal is to ensure that a sufficient amount of energy is transferred from the flowing drilling fluid to the solid particles, to prevent a buildup of a cuttings bed (Skalle, 2012).

In horizontal sections, the importance of slip velocity is significantly reduced. The amount of vertical travel is limited to a few inches compared to potentially thousands of meters in vertical sections. Thus it becomes more important to make sure the solids are "kicked up" from the solids bed that is bound to accumulate at the lower end of the wellbore. As will be explained in the next section, proper cleaning of horizontal sections is largely dependent on drill string RPM in addition to flow velocity, and to a lesser degree, fluid properties (Skalle, 2012).

Drilling with a large diameter casing or liner results in a smaller annular flow area between the string and wellbore. As can be seen in Eq. 4-1 the annular flow area, $\boldsymbol{A_{annulus}}$, is directly correlated to the difference of the squares of the outer and inner diameter of the well bore:

$$\boldsymbol{A_{annulus} = \frac{(d_o^2 - d_i^2) * \pi}{4}} \qquad \textbf{Eq. 4-1}$$

Furthermore, the flow velocity, $\boldsymbol{v_{annulus}}$, is determined by the relationship between the flow rate and annular flow area, as seen in Eq. 4-2:

$$\boldsymbol{v_{annulus} = \frac{Q}{A_{annulus}}} \qquad \textbf{Eq. 4-2}$$

Thus, the flow velocity will be significantly higher in sections drilled using large diameter casing or liner compared to regular drill string, provided that the flow rates are comparable.

Pipe-to-Hole Area Ratio (PHAR) is a measure of the relative size of the pipe in relation to the wellbore. This parameter is often used in order to determine the appropriate pump rate and drill string RPM needed for achieving sufficient wellbore cleaning in medium (~35^{o}- ~60^{o}) and high inclination wells (>60^{o}) (K&M Technologies, 2011).

PHAR is calculated using Eq. 4-3:

$$\boldsymbol{PHAR = \frac{{R_h}^2}{{R_p}^2}} \qquad \textbf{Eq. 4-3}$$

R_h refers to the radius of the wellbore, and R_p refers to the radius of the pipe.

The hypothesis states that there is a relationship between the PHAR, the pump rate, as well as drill string rotation required to maintain sufficient wellbore cleaning. Less drill string rotation is required in order to maintain a viscous coupling, and thus good hole cleaning, when drilling with a low PHAR, such as is the case when drilling with casing or liner.

Figure 4-8 illustrates the rather limited effect pipe rotation alone has on the cuttings bed, while Figure 4-9 illustrates the added effect of the viscous coupling. The green color represents zones with low velocity flow, while the red color represents a zone of high velocity flow.

The PHAR ratio of wells drilled using CD/LD systems will necessarily be lower than a comparable conventionally drilled well. The fluid velocities will also be high around the intervals of the strings exposed to the formation. Thus it is reasonable to assume that wellbore cleaning in these intervals will be better than would be the case if the well is drilled conventionally. Cleaning will still be a concern in the well sections where the difference between the string diameter and well diameter is the greatest, which is in the upper sections.

Figure 4-8: The effect of pipe rotation alone on the cuttings bed

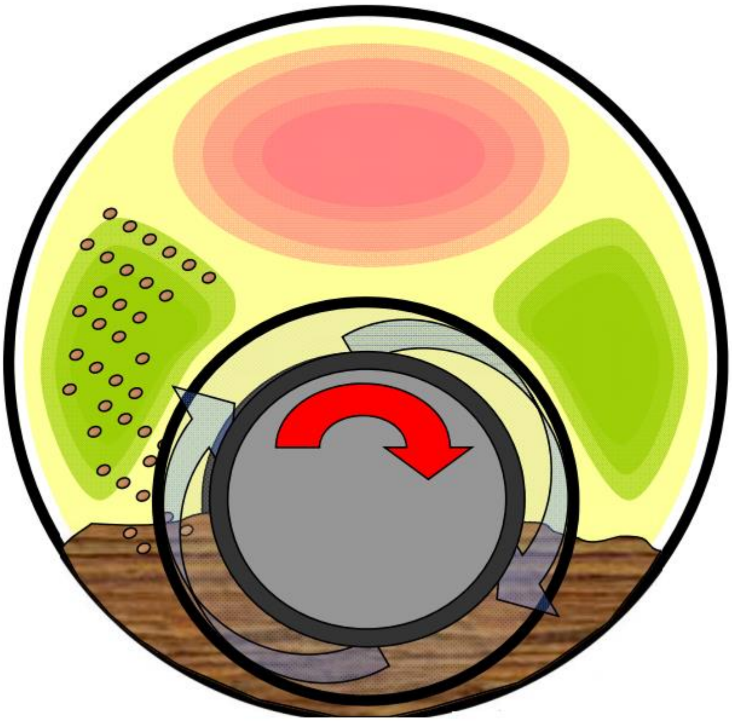


Figure 4-9: The effect of the viscous couple on the cuttings bed

4.3.5 Drilling with Losses

Due to the small annular flow area, cuttings transport and ECD may be maintained while circulating with a significantly lower flow rate compared to a conventional drilling. This, combined with the Smear Effect, may provide a significant benefit when drilling through high-loss formations, such as vugs, caverns and big fractures where losses cannot be cured. Lower flow rates helps losing less mud, as well as controlling ECD to better regulate the pressure differential between the string and the formation.

The result is a significant improvement to HSE compared to conventional drilling, as excessive fluid losses may bring the well into severe underbalance, which may lead to loss of the well, kicks or blowouts. It is also beneficial with regards to Flat Time; drilling is usually halted until the losses are cured. This may not be necessary when drilling with liner or casing (Karimi, et al., 2011).

4.4 Limitations

4.4.1 Torque, Drag and Friction

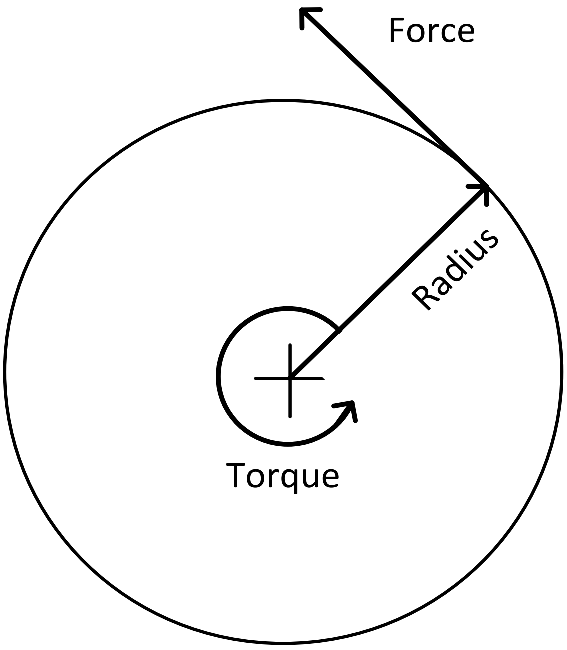


Figure 4-10: Torque Vector diagram

$$Torque = Force * Radius$$

Torque and drag are very often limiting factors in *Extended Reach Drilling* (ERD). Some of the parameters that have influence on the torque are (Thingbø, 2011):

- The length of the drill string
- The weight of the string
- The radial and axial velocity
- The well deviation
- The friction factor

The increased diameter of liner and casing strings compared to conventional drill pipe means that more torque is required in order to rotate the string as well as increased drag forces acting on the string.

The Plastering Effect typically reduces the risk of getting stuck due to differential sticking, lost circulation scenarios and formation collapse when using CD/LD. But there is an additional risk of getting stuck while drilling with liner and casing due to wall-to-wall friction and the inherent stiffness of the string; sensitivity to *Dog-leg Severity* (DLS) is higher than with a conventional drill string. While it is possible to achieve very high DLS[10] with conventional drill strings, DLS exceeding 3.5°/30m should be avoided[11] when *running* casing and liner. It is assumed that the same restrictions apply when *drilling* with liner and casing in order to limit wear and to reduce downhole friction. Wellbore friction related stuck pipe issues may be reduced by limiting wellbore tortuosity[12], running casing/liner stabilization systems on the drill string and by utilizing designer mud systems (Carlsen, et al., 2000).

Performing torque and drag calculations falls outside the scope of this thesis.

4.4.2 Cementing

Cement typically has higher viscosity and gel strength than conventional drilling muds. The narrow annulus associated with CD/LD causes greater ECD while cementing, which may lead to formation fracturing, causing cement losses and a resulting insufficient cement job. This may also lead to loss of well control and kick/loss cycles. Formation of *micro-annuli* due to cement channeling is a risk, as this provides a flow path for hydrocarbons, resulting in the loss of a primary barrier. In order to reduce the risk of channeling issues and formation of micro annuli, the casing or liner string has to be fitted with centralizers, which helps with maintaining annular clearance in deviated sections. On the upside, the reduced annular volume will lead to reduced cementing costs (Carlsen, et al., 2000).

When running casing or liner conventionally a float valve is installed towards the end of the string, which is designed to only allow flow in one direction. The purpose is to prevent cement from flowing back into the string. Such devices may also be installed in the string when using non-retrievable BHA CD/LD systems. When using retrievable BHA systems, however, the valves have to be run downhole on a wireline, coiled tubing or drill pipe after the inner string has been pulled out of the hole. This has the potential to make cementing non-retrievable systems more time consuming.

4.4.3 String Elongation and Vibrations

Mud motors stalling cause an increase in fluid pressure on the inside of the drill string. Because the diameter of casing and liner piping is much greater than drill pipe, they tend to elongate more with increasing internal pressure. Drill string elongations increases the compressive forces acting on the bit since the string is fixed at the top. The increase in compressive forces acting on the bit increases the torque required to

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[10] Schlumberger's Archer High Build Rotary System is capable of achieving DLS of 18°/30m (Schlumberger LTD., 2014).
[11] Conversation with Jafar Abdollahi, 25th of April, 2014.
[12] Reduced wellbore tortuosity is a property inherent to liner and casing drilling systems

rotate the bit, which increases the pressure drop across the motor, which further increases the *Weight on Bit* (WOB). This effect has a tendency to cause additional vibrations, and thus damage to downhole equipment (Strickler, et al., 2005).

4.4.4 ROP

The chip hold-down effect was mentioned when discussing MPD methods. The increased AFP and ECD associated with CD/LD will increase the pressure acting on the bottom hole, which may have a negative effect on ROP, and increase bit wear and bit balling issues.

4.4.5 Stuck Pipe

The increased diameter of the casing or liner leads to additional torque and friction, as has been stated earlier. A result of this fact is an increase in surface contact area between the casing/liner and the formation, which, in turn, leads to an increase in the forces acting on said area. Depending on the differential pressure between the wellbore and formation, this may lead to an increase in differential sticking issues. With that being said, the smear effect may counteract this to some extent.

There are factors involved when using CD/LD which may both alleviate and aggravate causes of stuck pipe incidents. In sum, it would seem that the risk of becoming differentially stuck, or stuck due to friction, is greater than when using conventional methods.

4.4.6 Surge & Swab

Using CD/LD methods eliminates surge and swab concerns while tripping. Surge and swab fluctuations can be much more of an issue while drilling, however. The string is forced to move along with the MODU when the string is suspended in the slips, and the string is still exposed to open formations in this situation; the reduced annular flow area will increase the magnitude of the fluctuations caused by heave induced axial string movement.

4.5 Health, Safety & Environment

Sufficient evidence exists to say that these technologies prevent fluid losses to some extent. However, CD and LD are preventative measures. If the formation has already fractured, the smear effect may alleviate fluid losses by sealing up already existing fractures, but so far the phenomenon is too unpredictable for CD/LD to be used to “repair” fractured wells.

When performing casing drilling, the ability to shear the string and seal the BOP when encountering kicks may be a concern. Conventionally, BOPs are not suitable for shearing casing tubulars. This is not a concern while using LD, at least not after the liner string has passed the shear rams. Potential hazards should be identified prior to running casing and liner strings.

As has been stated previously, tripping takes place in a sealed-off wellbore, and most well control incidents takes place while tripping. Therefore, it is reasonable to assume that using CD/LD has the potential to alleviate certain HSE concerns, especially when drilling through formations in which fluid losses are expected, such as poorly consolidated sandstone formations.

4.6 Summary

Summaries of important potential benefits with regards to HSE and cost, and some potential disadvantages involved with using CD/LD systems can be seen in Table 6 and Table 7, respectively.

Table 6: CD/LD Summary Benefits

Property	Potential Benefit	Result	Comment	Cost	HSE
Increased drill string diameter	Narrow annular clearance	Higher flow velocities	May be able to increase BHP while uphole pressure remains unaffected		
			Improved cleaning		
Casing/lining hole while drilling	Casing/liner always at TD	Keep every foot drilled	Can drill until stuck		
	Eliminate tripping in casing/liner	Little chance of well control issues while tripping	Eliminate surge/swab during tripping		
		Time saved tripping			
		Limits exposure of formation to drilling fluids	Reduce wellbore stability issues		
Smear Effect	High quality mud cake Plastering	Reduced fluid losses	Less chance of kick/loss cycles		
		Increased formation strength	Less chance of well collapse		
Increased string stiffness	Reduces wellbore tortuosity	Improves wellbore quality	May also reduce stuck pipe issues		
	Reduces string vibrations	Improve equipment life			

Table 7: CD/LD Summary Disadvantages

Property	Potential Disadvantages	Result	Comment	Cost	HSE
Increased Drill String Diameter	Narrow Annular Clearance	Higher Flow Velocities	Increased AFP, may cause BHP to exceed fracture pressure		
			Increased chip hold-down forces – Reduced ROP		
			Increased abrasive effects on formation, may cause washouts		
		Increased wear and abrasion on casing/liner	Reduced life expectancy		
		Cementing issues	May cause cement channeling and forming of micro-annuli		
		Surge and swab when drilling from floaters	May be a problem during drilling due to axial string movement		
		Will increase torque and drag	May lead to more stuck pipe incidents		
	May require some modifications to rig equipment	Equipment must be modified and certified			
	Mounting sensors on string problematic	Getting along-string data is a challenge outside the BHA			
	Increased torque & drag	Additional stuck pipe challenges			
		May be necessary to increase size of top drive	Limits length of drilled interval		
	Increased string elongation	May cause stick/slip issues	May result in damaged downhole equipment		

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5 Supporting Technologies

5.1 Wired Drill Pipe

Conventionally, communication between the tools in a drill string and the facilities / personnel situated topside is exchanged using *Mud Pulse Telemetry* (MPT). MPT subs are mounted in the drill strings, and uses valves to modulate the flowing drilling fluids, transmitting information by generating pressure pulses that may be detected topside.

It is a fact that the industry is drilling ever deeper and moving into deeper waters in the pursuit of promising prospects. As the need for downhole information has increased along with this development, the following limitations of the MPT technology have been identified:

- Data transfer capacity of ~20 bits per second (bps) under optimal conditions
- Signal deteriorates as the length of the well increases (National Oilwell Varco)
- Signal transfer speed is limited by pressure wave propagation velocity
- The integrity of the signal is dependent on continuity and circulation of the mud column. Signal continuity is compromised when the pumps are shut off, when the well is taking significant amounts of gas influx, and in situations where the well is taking significant mud losses
- The mud pulser may limit the use of Lost Circulation Material (LCM), due to risk of clogging

The most commonly used Wired Drill Pipe technology, known as the IntelliServ Broadband Networked Drillstring (shown in Appendix Figure 1 in Appendix C), incorporates an integrated armored signal transfer circuit. The cable passes through drilled holes in the connections, and ends in inductive coils that enable the signal to pass from one joint to the next. These coils come into close contact with each other when connections are made. The inductive nature of the coils means that they don't have be in direct contact; insulating materials does not prevent the signal from being passed from on coil to another. In spite of this, loss of signal strength will occur as the signal passes over many joints of pipe. Therefore, battery-powered booster subs are deployed every ~1500ft. These booster subs (also referred to as network nodes or links) also provides connection points for *Along-String Measurements* (ASM). The drill pipe is connected to the BHA tools by the means of an Interface Sub, enabling 2-way communications between the BHA and topside facilities. The drillstring is connected to surface servers via a data swivel housed in the top drive (Edwards, et al., 2013).

WDP mitigates several of the shortcomings identified in relation to conventional MPT:

- Transfer capacity can be significantly higher : ~56kbps for the first generation of NOV's IntelliServ system, while the second generation has been reported to be able to sustain transfer rates of > 2Mbps (National Oilwell Varco)
- Signal transfer is near instantaneous (Hernandez, et al., 2010)
- Signal is not subject to significant deterioration; signal integrity remains independent of the continuity and circulation of the mud column (National Oilwell Varco)

Some of the benefits of Wired Drill Pipes are inherent to the wired pipe system in itself. Many, however, are specific to the MWD/LWD tools being used, and may vary from one provider to the next (Edwards, et al., 2013):

- The directional driller is able to control the trajectory of the well in real time (National Oilwell Varco)
- Engineers sitting in an Integrated Operations Center can monitor the formation, mud and drilling parameters in real-time using networked MWD/LWD tools, improving real-time understanding of the formation, providing valuable data about production zones, downhole navigation and well placement (Hernandez, et al., 2010)
- Enables high-resolution annular pressure measurements, even in the absence of flow, allowing for accurate ECD management and Surge/Swab monitoring during tripping (Hernandez, et al., 2010)
- Kicks and lost circulation events may be detected even in the absence of flow (Hernandez, et al., 2010)
- Well control events may be detected much earlier, allowing potentially hazardous situations (such as shallow gas and water) to be mitigated in a matter of minutes (Hernandez, et al., 2010)
- Bottom-hole telemetry can be transmitted and received while the mud pumps are turned off and in situations where severe mud losses are encountered (Hernandez, et al., 2010)
- Information is downloaded in real time, eliminating the need for return trips to retrieve data (Hernandez, et al., 2010)

- Real-time surveying help reduce the "cone of uncertainty", and allows for more accurate well placement (less than one minute compared to six minutes using MPT (National Oilwell Varco))
- Improve ROP by accurate pressure measurements (Hernandez, et al., 2010)
- Less chance of plugging tools as the mudpulser may be eliminated (National Oilwell Varco)
- Enables data transmission even while drilling in nitrogen aerated mud (CBM) (National Oilwell Varco)
- May indirectly improve cost efficiency by reducing mud losses (National Oilwell Varco)
- Ability to monitor downhole tool status (bit gauge, wear status, etc.) (Hernandez, et al., 2010)

If or when such systems are standardized for drilling operations, the need for down-hole processing power and data storage may be significantly reduced (since information can be sent topside for processing in a much more efficient manner), thus yielding a potential reduction in tool cost and increase in reliability. (National Oilwell Varco). In addition, WDP is considered suitable for through string operations, such as through string logging (both gravity and tractor-driven), and ball/wiper/dart drops (National Oilwell Varco).

Raw data access

Since the data transfer capacity using MPT is very limited, data recorded downhole from logging tools are usually processed, compressed and stored in the tools before being transferred topside in intermittent data bursts or retrieved from storage once the tool is pulled out of the wellbore. This requires a certain amount of processing power and storage (depending on the tool in question), adding to the complexity of the tools, which may also affect reliability of the components in question. Using WDP enables continuous exchange of raw data, which reduces the need for downhole processing power and storage. Benefits include, but are not limited to:

- Reduced tool cost
- Less time spent running wireline
- Less time spent tripping due to tool failure
- Downhole imaging may help detecting wellbore stability problems in real time
- Higher test sampling rate (Edwards, et al., 2013)

Utilizing wired drill pipes also opens up for improved vibrations monitoring. Excessive drill string vibrations are well known for damaging complex and expensive drill string tools, such as MWD/LWD subs. Basic components such as drill pipes and drill bits are also at risk of damage due to uncontrolled string vibrations. In addition, string vibrations reduce the mechanical efficiency of the drill bit, as mechanical energy is transformed into vibrations, "stealing" energy from the drill bit. This phenomenon is known as *vibrational founder*. Thus, monitoring string vibrations can yield greater operational efficiency in the form of improved ROP in addition to improving bit life, as it enables the driller to adjust WOB and RPM of the drill string accordingly (Hernandez, et al., 2010).

Measurements While Drilling / Logging While Drilling

Modern MWD/LWD methods enable drillers and engineers/physicists to procure information continuously while drilling by running some of the most advanced and expensive tools of the industry in the drilling string. Conventionally, the information is sent topside via MPT. As previously mentioned, however, the data transfer capacity of this system has its limitations, so the tools are also equipped with data storage capacities, so that the data can be analyzed when tools are brought to the surface.

Using networked pipe with LWD/MWD tools may thus increase the amount of information available at any point in time.

5.2 Along-String Measurements & Seismics While Drilling

Using networked pipe allows for distributing pressure and torque sensors, commonly referred to as Along-String Measurements, as well as *Seismics While Drilling* (SWD) sensors along the drill string. Such systems allow continuous monitoring of the torque/drag situation in the wellbore and drill string, as well as ECD and kick (size and migration) status. This in turn enables the identification and mitigation of well control events before they reach critical mass, opens up the possibility of recording one-way seismics, and transmitting the information topside. (Hernandez, et al., 2010)

Pressure and torque information can be used to avoid stick/slip, twist-offs and string buckling while drilling, and can be used to accurately track kicks as they move up the well. Potential advantages include less operational problems/expenses such as downtime due to fishing, lost equipment and sidetracking. Accurate ECD monitoring is especially useful when drilling slim hole, ERD wells and wells with a narrow mud window to name a few applications. SWD can be used to evaluate the geology (rock strength, consolidation, geomechanical stability, etc.) of the formations surrounding the drill string as the well is drilled, increasing the crews' operational knowledge about the downhole conditions. (Hernandez, et al., 2010)

5.3 Concept Study: Liner Drilling with Expandable Systems

Conventional drilling operations start with a borehole with a wide diameter which becomes progressively narrower with depth. This happens due to the tapering effect described in Chapter 3.4.2. The ideal is to drill monobore wells, where the well is drilled with a constant diameter from top to bottom. Drilling with a constant diameter (ideally around 9 ½" due ROP optimization concerns) may yield the cost saving benefits shown in Table 8:

Table 8: Cost saving benefits of drilling monobore wells

Property	Cost Saving Benefit
Reduced need for tools of different sizes	Reduction in tool cost
Fewer concentric casing strings	Reduced casing expenditures Allows reduction in size of BOP and drilling riser Less deck space needed for storage Reduced amounts of consumables needed (fluids, casing, cement, etc.) Smaller rigs
Less rock have to be removed in order to drill the well	Less time spent drilling Higher average ROP Reduced need for cleaning and disposal of cuttings
Increased diameter of the producing interval	Increased production rates
Less steel left downhole	Faster and less complicated Plugging and Abandonment

Expandable tubulars is a well-established technology which enables drillers to get one step further towards the ultimate goal of drilling monobore wells. Special deformable tubes are run downhole, cemented and expanded to the previous casing strings inner diameter using mechanical and hydraulic power while the cement is still setting. Unlike conventional casing and liner, expandables allow drilling monobore diameter wells.

Eq. 5-1 shows the relationship between producing oil flow rate, well radius and pressure (Golan, et al., 1996). As can be observed, any increase in well diameter would yield a positive impact on production rate:

$$\boldsymbol{q_o = \frac{2\pi kh(p_R - p_{wf})}{\mu_o B_o(ln\frac{r_e}{r_w} - \frac{1}{2})}} \qquad \textbf{Eq. 5-1}$$

In order to illustrate the benefits of maintaining the wellbore diameter in producing intervals, Eq. 5-1 will be used to evaluate the increase in productivity potential resulting from increasing well diameter by Eq. 5-2:

$$\frac{q_{o,2}}{q_{o,1}} = \frac{\ln\left(\frac{r_e}{r_{w,1}} - \frac{1}{2}\right)}{\ln\left(\frac{r_e}{r_{w,2}} - \frac{1}{2}\right)}$$ **Eq. 5-2**

A drainage radius of 400m was arbitrarily chosen. The results can be found in Table 9. As can be seen, the increase in flow rate potential may be substantial.

Table 9: Comparison of production potential as a function of wellbore diameter

Production Potential								
5 in. vs 7 in.			5 in. vs 9 5/8 in.			7 in. vs 9 5/8 in.		
r_e	400	m	r_e	400	m	r_e	400	m
$r_{w,1}$	5	in	$r_{w,1}$	5	in	$r_{w,1}$	7	in
$r_{w,2}$	7	in	$r_{w,2}$	9.625	in	$r_{w,2}$	9.625	in
$q_{o,2}/q_{o,1}$	1.042528396		$q_{o,2}/q_{o,1}$	1.086251		$q_{o,2}/q_{o,1}$	1.041939	
Δq	4.25 %		Δq	8.63 %		Δq	4.19 %	

Replacing the casing or liner while performing CD/LD with expandable tubulars may be a step towards the goal of drilling monobore wells. The potential advantages of such a system, *Expandable Tubular Drilling* (ETD), are numerous, some of which are listed in Table 8. Paired with the inherent advantages associated with CD/LD which are listed in Chapter 4, this may constitute a powerful tool to use in certain situations (Kumar, et al., 2010).

A useful application of such a system would be as contingency tubular. Figure 5-1 shows a situation where LD has been used to penetrate a reservoir. At a point, a formation hazard has caused the string to become stuck. When drilling using conventional LD systems (left, Figure 5-1), the driller has the choice to drill ahead with a smaller liner, reducing the producing well diameter. Alternatively, the well may be drilled ahead using conventional drill pipe and reamers. After the well is drilled, expandable tubulars may be installed and expanded. Utilizing ETD in such a situation (right, Figure 5-1), instead of the aforementioned alternatives, is likely to enable the driller to drill ahead while avoiding tapering of the wellbore, saving rig time in the process.

Using ETD would not be without its challenges, however. The metals used in expandable tubulars are softer and more flexible than conventional tubulars in order to avoid tensile failure during expansion. The fact that the annular clearance is a lot narrower when using liner or casing in place of drill pipe leads to several hydraulic and mechanical challenges. These properties may lead to an increase in wear and fatigue on the tubulars, which in turn may lead to pipe failure and complications during expansion. It is also uncertain whether expandable tubulars have the burst and collapse ratings needed to withstand the well pressure.

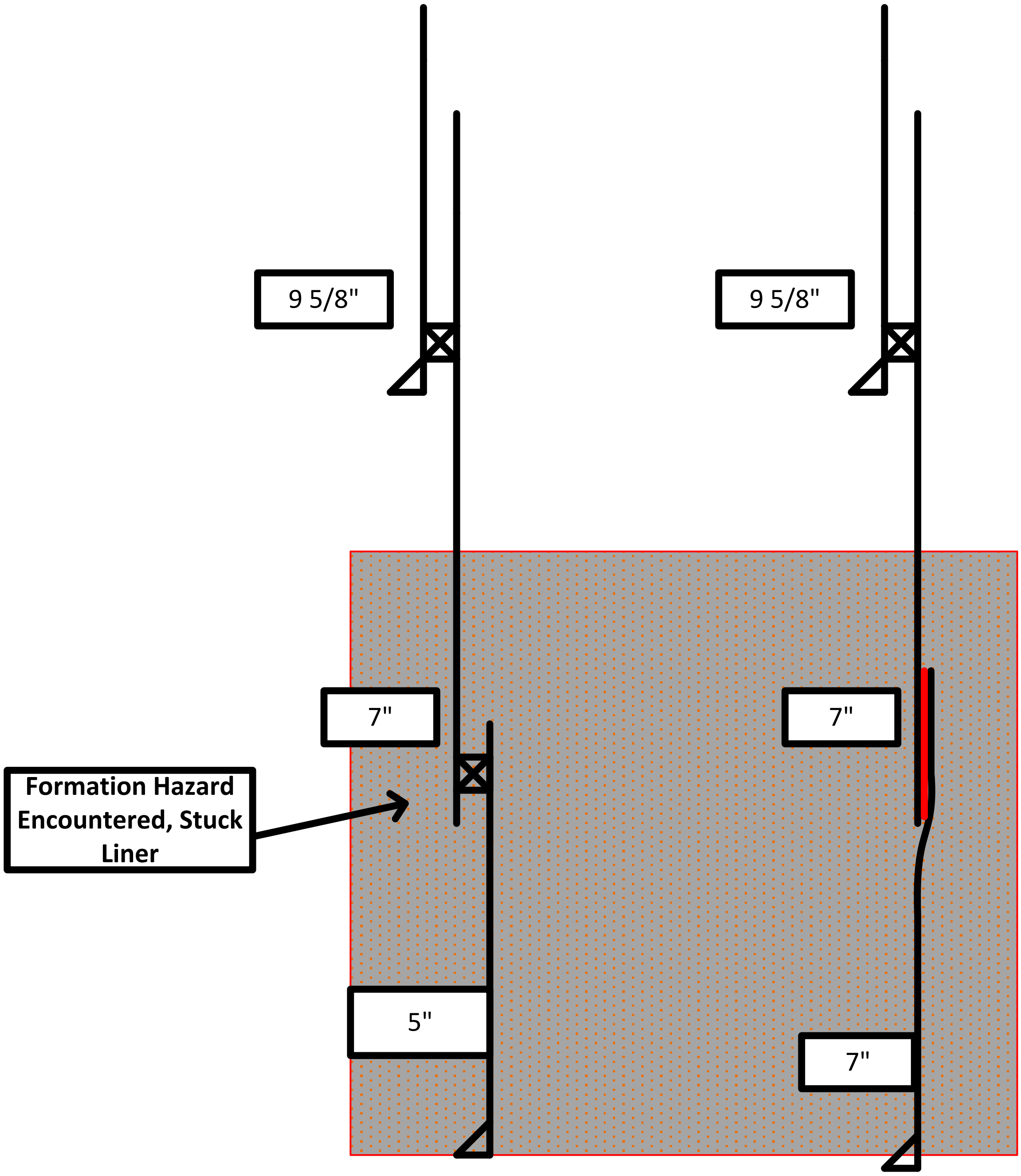

Figure 5-1: ETD used as contingency (right). Conventional Liner Drilling contingency (left)

5.3.1 Expansion Methods

Expandable tubulars are usually mechanically expanded either top-down or bottoms-up, with either a fixed-cone expansion tool or rolling cone expansion tool.

5.3.1.1 Fixed-Cone Expansion

When a fixed-cone expansion tool is used, the tool is mounted at the bottom of the tubular string, expanding the string bottoms-up. The force required is typically generated through hydraulic pressure behind the swage, sometimes supplemented by tension in the string (Innes, et al., 2004)). The top of most expandable liner strings is sealed against the base casing using expandable hanger joints with several elastomer seals, and tapered towards the end. After expansion, the expansion cone folds together and is pulled out of the hole. When drilling ahead, the shoe joint and aluminum transition nose is drilled. During expansion, propagation forces expanding 13 3/8 in. casing can approach 300,000lbs. The casing is typically expanded one stand at a time. Fixed-cone expansion normally leads to a 4% reduction in tubular string length (Gusevik, et al., 2002), and the wall thickness is reduced by 4-7% (Innes, et al., 2004).

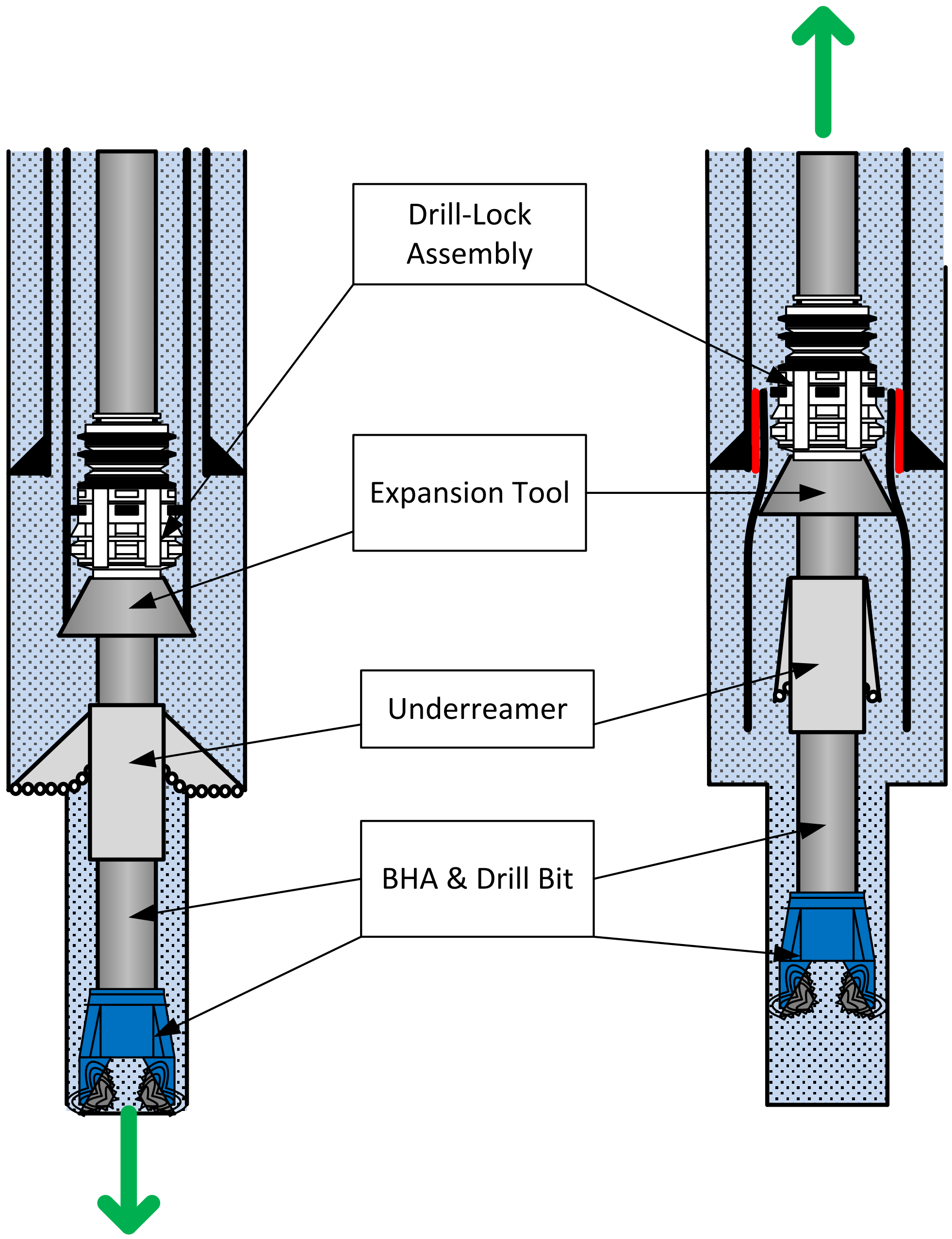

Figure 5-2: Bottoms-up Fixed-Cone Expansion of a Retrievable BHA ETD system

5.3.1.2 Rolling Cone Expansion

When using a rolling cone expansion tool, the tool can be mounted at the end of the string, expanding the tubulars bottoms-up, or may be run downhole after the tubulars are installed and expanded top-down (the latter is depicted in Figure 5-3). The rollers impart a radial force intended to overcome the circumferential yield strength as the tool is rotated around its longitudinal axis, and the tubular is expanded by successive passes by the rollers which gradually stretches out the tubular. Rolling cone expansion is usually not accompanied by a corresponding shortening of tubular length, and allows for tubular expansion with relatively low axial loads; axial loads typically amount to 20% of equivalent fixed cone swage based expansions (Innes, et al., 2004).

The energy needed to expand the tubulars may be provided by the top drive, or by a PDM, provided that the expansion tool is seated below the PDM in the BHA.

5.3.2 String Configuration

5.3.2.1 Non-retrievable BHA systems

When utilizing non-retrievable BHA CD/LD systems, the bit is fixed at the end of the string along with the shoe. Bottom-up expansion could be executed using both fixed-cone and rolling cone expansion tools. In that case, a drill string would have to be run in hole and latched onto the expansion tool, and the drill bit assembly would have to be disconnected before expansion is initiated. Alternatively, it might be plausible for expansion to work by utilizing an *e-line*[13] and an electrically powered jacking tool latched onto the expansion tool in order to provide the axial force required. It is uncertain whether tools capable of performing such a function exist today, or if the equipment used is able to deliver sufficient power downhole.

Top-down expansion could be executed in much the same manner as bottoms-up expansion, albeit with a rolling cone expansion tool. This method would look much the same as expansion of conventional expandable tubulars look today.

5.3.2.2 Retrievable BHA systems

Expanding retrievable BHA expandable tubulars systems poses another set of challenges. Some retrievable BHA systems have an underreamer fitted in the BHA intended to expand the hole drilled by the pilot string. This method seems the most preferable, due to the apparent lack of tubular contraction, and the energy required to expand the tubulars.

When drilling with expandable tubulars, the hole must be reamed to a size accommodating the expansion, while at the same time leaving enough room for a proper cement job. This may cause a problem if no underreamers are available capable of sufficient hole expansion. Examples of two typical dimensions of expandable tubing and the associated wellbore expansion ratios needed are displayed in Table 10. As is seen, these values far surpass those of available underreamers on the market per 2012 (see Table 16 in Appendix D).

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[13] Wireline with an incorporated electrical conduit

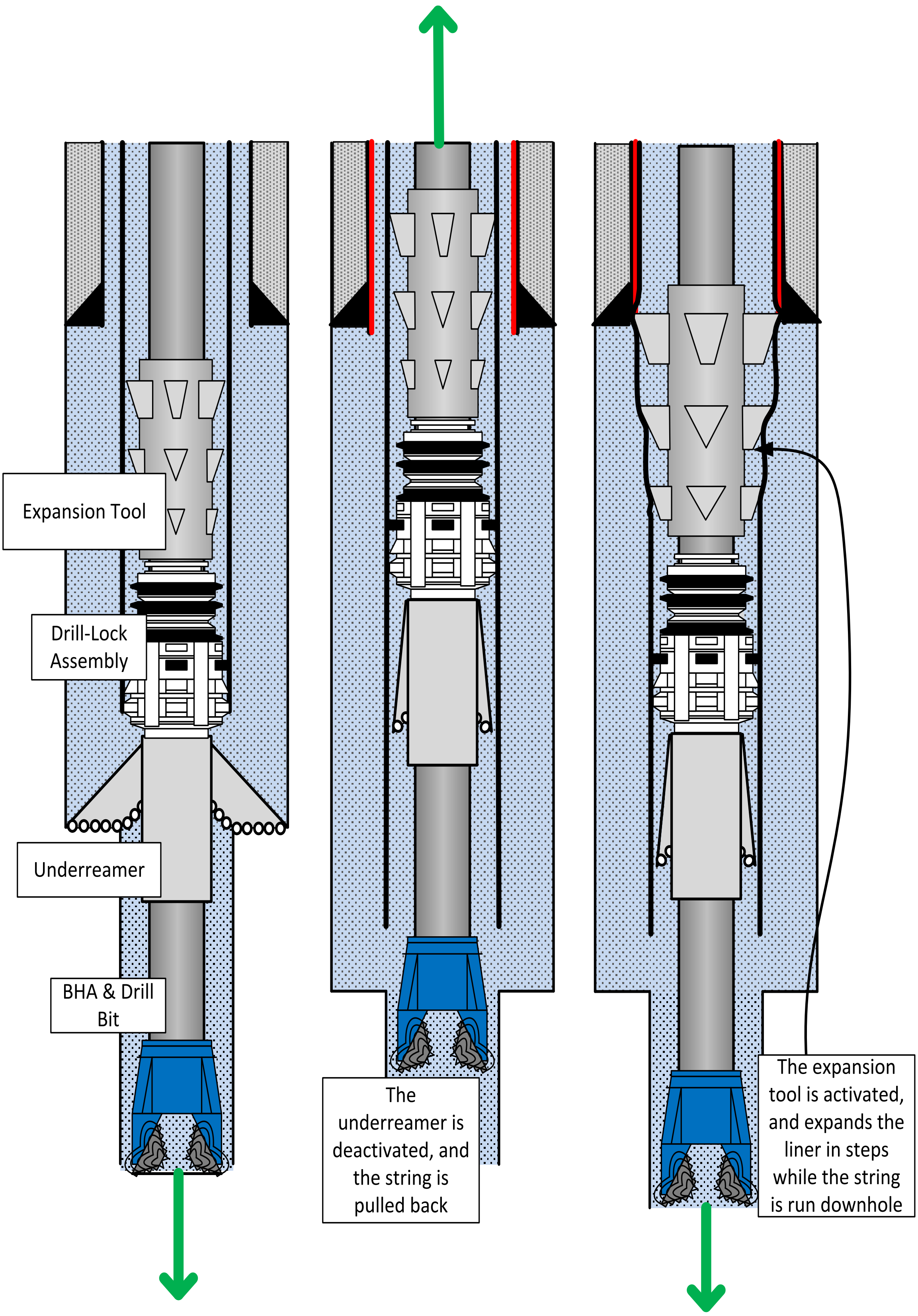

Figure 5-3: Top-down Rolling Cone Expansion of a Retrievable BHA ETD system

Table 10: Expandable tubular dimensions and associated hole expansion ratios

Expandable Tubular Dimensions	Pre-Expansion Diameter	Post-Expansion Diameter	Reamer Diameter	Required Hole Size	Wellbore Expansion
[in]	[in]	[in]	[in]	[in]	[%]
7-5/8"x9-5/8"	7.625	9.625	6	10.75	79.17 %
9-5/8"x11-3/4"	9.625	11.75	7	13.375	91.07 %

5.3.3 Business Case

In order to evaluate whether expandable tubulars are suitable for the applications mentioned thus far in this chapter, a *Finite Element Method* (FEM) analysis should be performed. This lies beyond the scope of this thesis.

Table 11 shows a simple attempt to estimate and compare the time spent drilling wells and installing casing/liner using the conventional methods and retrievable BHA ETD. The tripping speed of drill string and casing/liner was set to 500m/hr and 100m/hr, respectively[14]. The expansion rate of the expandable tubular was set to 7.8ft/min (Fanguy, et al., 2004). There are other factors that come into play as well, such as cementing, time spent making up BHA, and the time spent on well control issues and stuck pipe incidents. CD/LD methods have some benefits w.r.t. well control issues and stuck pipe incidents, as was mentioned in Chapter 4. These can be expected to carry over to ETD methods.

The results listed in Table 11 can hardly be expected to be representable for a real-life application. However, a 26% reduction in time spent drilling and installing tubulars, even for a rudimentary calculation such as this, added to the benefits listed in Table 8 is significant and warrants further investigation.

[14] Conversation with Sigbjørn Sangesland, 9th of May, 2014

Table 11: Time to drill comparison between conventional methods and expandable liner drilling

ROP	20	m/hr
Expansion Rate	142.6464	m/hr
Drill pipe tripping speed	500	m/hr
Casing/Liner tripping speed	100	m/hr
Length of interval	1000	m
Length of well	3000	m

	Conventional	ETD	
Time spent drilling	50	50	hrs
Time spent tripping drill pipe	6	6	hrs
Time spent tripping liner	30	0	hrs
Time spent expanding liner	0	7.010341656	hrs
Sum	86	63.01034166	hrs

5.3.4 Discussion

There seems to be a definite economic potential to using ETD. Initial evaluation suggests that using a retrievable BHA mounted rolling cone expansion tool to expand the tubular from the top down may be the most practical solution. The mechanics involved in engaging, disengaging and retracting a BHA mounted rolling cone expansion tool may be simpler and more reliable than a fixed cone expansion tool. In addition, no hydraulic pressure is required behind the swage for force the tool upwards, as the forces required to expand the tubulars are generated by flowing drilling fluids much in the same manner as when using PDMs. Over a 1000m interval, a 4% contraction would mean that the length of the tubulars is reduced by 40m. This could mean the difference between setting the tubular shoe inside a reservoir, or setting it above.

6 Theoretical Background

6.1 Drilling Hydraulics

During drilling operations, drilling fluids are pumped downhole from the rig and circulated through the borehole. Drilling fluids play a major role in modern drilling operations. The most important functions of drilling fluids are to serve as the primary barrier during conventional drilling operations, and to remove cuttings from the well. In addition, the drilling fluids help lubricate and cool the drill bit and BHA, as well as conveying information between topside facilities and BHA via conventional MPT systems.

Drilling fluids usually consist of an oil, - or water-base, with weight material and other additives mixed in (Skalle, 2012).

6.1.1 Bottom Hole Pressure

When the pumps are shut down, the well is said to be under static conditions. True stationary conditions can only be found in a lab, however, as the drilling fluids are always subject to transient effects, even after the pumps are shut down and the fluids have stopped circulating:

- Solids settle over time
- Temperature gradients affect the fluids and the formation
- The properties of fluids and fluid additives may change due to temperature, pressure, acidity and chemical reactions with downhole materials

These effects may all have an impact on the downhole conditions, and ultimately, the BHP and pressure distribution along the wellbore. While they are worth discussing, simplifications have to be made in order to make approximations and predictions. Therefore, the following assumptions have been made:

- Cuttings concentration remain constant after the pumps are shut down
- Cuttings are evenly distributed in the well, even under static conditions
- Fluid properties remain constant
- The pressure loss resulting from transporting cuttings out of the well is negligible

6.1.1.1 Static Conditions

Under static conditions, the BHP is defined by the height and density of the fluid column (hydrostatic pressure), as shown in Eq. 6-1:

$$\boldsymbol{p_{hs} = \rho * g * D} \qquad \textbf{Eq. 6-1}$$

Where: ρ= drilling fluid density, g=acceleration due to gravity pull, and D= vertical depth of the well.

Drilling successfully depends on transporting solids away from the borehole. The fluid contains a certain amount of solids at any time, quantified by the parameter $c_{p,0}$, which is defined by Eq. 6-2:

$$\boldsymbol{c_{p,0} = \frac{Solids\ Volume}{Mud\ Volume + Solids\ Volume}} \qquad \textbf{Eq. 6-2}$$

A well that has been at static conditions for a prolonged period of time will in practice have $c_{p,0} = 0$, as the solids suspended in the fluid may have settled depending on the rheology of the fluid and the geometry and density of the cuttings. The combined density of mud and solids, ρ_{mix}, may be expressed by Eq. 6-3:

$$\boldsymbol{\rho_{mix} = \rho_{mud} * \left(1 - c_{p,0}\right) + \rho_{solids} * c_{p,0}} \qquad \textbf{Eq. 6-3}$$

Substituting ρ_{mix} from Eq. 6-3 for ρ into Eq. 6-1 yields Eq. 6-4:

$$\boldsymbol{p_{hs} = \left(\rho_{mud} * \left(1 - c_{p,0}\right) + \rho_{solids} * c_{p,0}\right) * g * D} \qquad \textbf{Eq. 6-4}$$

6.1.1.2 Dynamic Conditions

The magnitude of the Annular Friction Pressure Loss depends on several parameters, such as borehole geometry, flow regime and fluid characteristics, pipe rotation and drillstring dynamics.

Hydraulic friction should be estimated as accurately as possible in order to (Thingbø, 2011):

- Determine the right bit nozzle size in order to optimize ROP
- Optimize cuttings transport to the surface
- Determine the proper pump size
- Estimate the annular pressure losses in order to stay within the mud window
- Detect unforeseen changes in SPP due to change in the hydraulic circuit

In a dynamic system the cuttings concentration ratio, $c_{p,0,}$ expressed in Eq. 6-2 should be expressed in terms of flow rates, as seen in Eq. 6-5:

$$c_{p,0} = \frac{q_{solids}}{q_{mud}+q_{solids}} \qquad \textbf{Eq. 6-5}$$

The volume rate of the solids suspended in the mud is expressed in Eq. 6-6:

$$q_{solids} = ROP * \left(\frac{d_{bit}}{2}\right)^2 * \pi \qquad \textbf{Eq. 6-6}$$

ROP is defined as Rate of Penetration (m/hr).

ECD is defined as the sum of hydrostatic pressure and pressure loss due to friction (Thingbø, 2011) (it is assumed that the distribution of cuttings is even throughout the well) by Eq. 6-7:

$$ECD = p_{hs} + \Delta p_f = \rho_{mix} g D + \Delta p_f \qquad \textbf{Eq. 6-7}$$

Where p_{hs} refers to hydrostatic pressure, and Δp_f to annular pressure loss due to friction.

6.1.2 Flow regimes

Fluid flows tend to be streamlined at low flow velocities. This type of flow regime is called *laminar flow* (shown in Figure 6-1). Laminar flow is characterized by smooth streamlines and highly ordered motion, and is usually encountered when highly viscous fluids such as oils flow in small pipes (Çengel, et al., 2006).

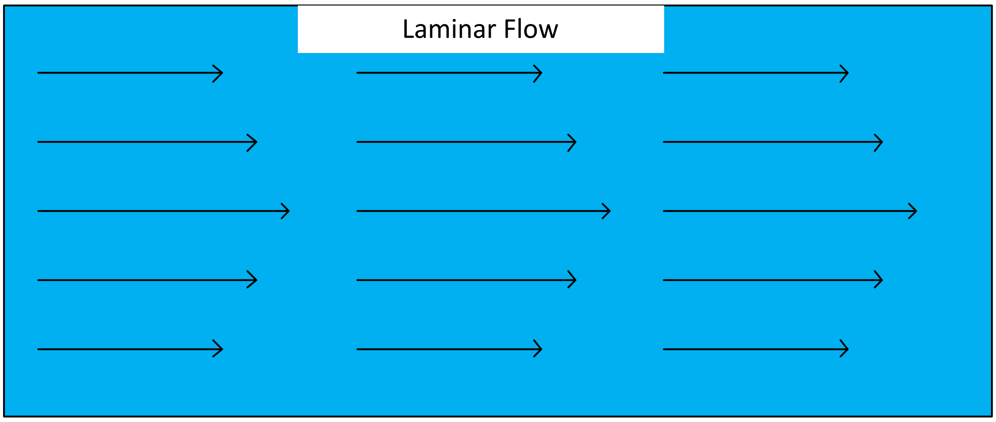

Figure 6-1: Laminar Flow

While the transition between laminar and turbulent flow regimes may be affected by the wall roughness, and inlet and outlet effects, the *Reynolds number* (Eq. 6-8) is the most significant factor. When the *Reynolds Number* exceeds a certain threshold, the streamlines characterizing laminar flows tend to be broken up, and the regime makes a transition over to *turbulent flow* (Figure 6-2). Turbulent flows are characterized by local velocity fluctuations and highly disordered motion. The transition from laminar flow to turbulent flow does not happen suddenly. Rather, regions in the flow tend to fluctuate between laminar and turbulent flows, before it becomes a *fully developed turbulent flow*. Most flows may in practice be described as turbulent (Çengel, et al., 2006).

Fluid flows are usually characterized as laminar for $N_{RE} < 1800$ and fully turbulent for $N_{RE} > 2100$. The interval covering $1800 < N_{RE} < 2100$ is called *transitional flow*, and is characterized by switching flow regimes. The transitional area will not be covered further in this thesis; fluids will be characterized as either *laminar* or *turbulent* (Bourgoyne, 1986).

The Reynolds Number is expressed for internal flow in a circular pipe by Eq. 6-8 (Çengel, et al., 2006):

$$\boldsymbol{N_{RE} = \frac{\rho \bar{v} D}{\mu}} \qquad \textbf{Eq. 6-8}$$

Where $\rho = fluid\ density\ \left[\frac{kg}{m^3}\right]$, $\bar{v} = average\ fluid\ velocity\ \left[\frac{m}{s}\right]$,

$D = diameter\ of\ pipe\ [m]$, $\quad \mu = dynamic\ viscosity\ [Pa * s]$

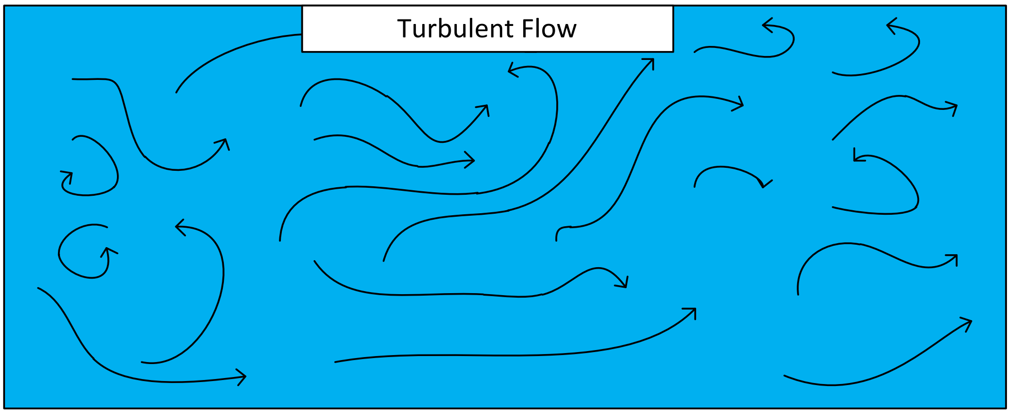

Figure 6-2: Turbulent Flow

6.1.3 Rheological Models

Fluid characteristics have to be determined in order to be able to estimate pressure losses in flows. *Viscosity* is a measure of a fluids resistance to flow (Çengel, et al., 2006), and is expressed using the symbol μ (unit Pa*s) for *dynamic viscosity*, and $\upsilon = {}^{\mu}/_{\rho}$ (unit ${}^{m^2}/_{s}$ for *kinematic viscosity*. Viscosity plays an important role for pressure losses and wellbore cleaning. A mathematical description of the viscous forces of a fluid is called a rheological model (Thingbø, 2011).

Shear rate, $\dot{\gamma} = -{}^{dv}/_{dr}$ (unit s^{-1}) expresses the "intensity of shearing action in the pipe, or change of velocity between fluid layers across the flow path (Skalle, 2012)".

The rheological model used to describe a given fluid will usually have a significant impact on the calculated behavior of said fluid, as depicted in Figure 6-3.

6.1.3.1 Newtonian Fluids

Newtonian fluids are characterized by having a linearly proportional relationship between sheer stress and rate of deformation (Çengel, et al., 2006), and is the simplest model used in drilling engineering. Shear stress for the Newtonian Model is defined by Eq. 6-9 (Skalle, 2012):

$$\boldsymbol{\tau = \mu\dot{\gamma}} \qquad \textbf{Eq. 6-9}$$

Due to the linear relationship between sheer stress and rate of deformation, the viscosity may be expressed by Eq. 6-10 (Skalle, 2012):

$$\boldsymbol{\mu_{eff} = \mu = \frac{\tau}{\dot{\gamma}}} \qquad \textbf{Eq. 6-10}$$

The shear rate for pipe flow is expressed by Eq. 6-11 (Skalle, 2012):

$$\boldsymbol{\dot{\gamma} = \frac{8\bar{v}}{d}} \qquad \textbf{Eq. 6-11}$$

And the corresponding shear rate for annular flow by Eq. 6-12 (Skalle, 2012):

$$\boldsymbol{\dot{\gamma} = \frac{12\bar{v}}{d_o - d_i}} \qquad \textbf{Eq. 6-12}$$

6.1.3.2 Non-Newtonian Fluids

The Newtonian fluid model is suitable for simple fluids like water. Most drilling fluids, however, are too complex to be characterized by a single value for viscosity. Such fluids does not usually exhibit a linear relationship between shear stress and shear rate, and are called *Non-Newtonian fluids*. They may be divided further into categories, depending on how the viscosity is affected by shear rate and how it changes over time at constant shear rates:

The viscosity of *shear-thinning*, or *pseudoplastic* fluids decrease with increasing shear rate, while that of *shear-thickening*, or *dilatant* fluids increase. The viscosity of *thixotropic* fluids decrease over time at constant shear rates, while that of *rheopectic* fluids increase.

For most cases it is satisfactory not to account for the thixotropic or rheopectic behavior exhibited by drilling fluids, though significant errors may arise in systems with numerous changes in flow direction and diameter. Most drilling fluids exhibit typical non-Newtonian behavior (Bourgoyne, 1986). Drilling fluids are typically pseudoplastic and thixotropic in nature (Skalle, 2012).

Bingham Plastic model

The Bingham Plastic rheological model is used to approximate the pseudoplastic behavior of fluids, and is defined by Eq. 6-13 (Bourgoyne, 1986):

$$\boldsymbol{\tau = \tau_y + \mu_{pl}\dot{\gamma}} \quad \textbf{Eq. 6-13}$$

A Bingham Plastic fluid will not flow until the shear stress, τ, exceeds a certain threshold, namely the yield stress, τ_y. When $\tau > \tau_y$, the change in shear stress is proportional to the change in shear rate (shown in Figure 6-3). This proportionality constant is called plastic viscosity, μ_{pl} (Thingbø, 2011), and is defined by Eq. 6-14 (Skalle, 2012):

$$\boldsymbol{\mu_{pl} = \frac{\theta_{600} - \theta_{300}}{\dot{\gamma}_{600} - \dot{\gamma}_{300}}} \quad \textbf{Eq. 6-14}$$

The effective viscosity for pipe flow is defined in Eq. 6-15 (Skalle, 2012):

$$\boldsymbol{\mu_{eff} = \mu_{pl} + \frac{\tau_y d}{6\overline{v}}} \quad \textbf{Eq. 6-15}$$

The corresponding effective viscosity for annular flow is defined in Eq. 6-16 (Skalle, 2012):

$$\boldsymbol{\mu_{eff} = \mu_{pl} + \frac{\tau_y (d_o - d_i)}{8\overline{v}}} \quad \textbf{Eq. 6-16}$$

The shear rate for pipe flow is expressed by Eq. 6-17 (Skalle, 2012):

$$\boldsymbol{\dot{\gamma}_{pipe} = \frac{8\overline{v}}{d} + \frac{\tau_y}{3\mu_{pl}}} \quad \textbf{Eq. 6-17}$$

And the corresponding shear rate for annular flow by Eq. 6-18 (Skalle, 2012):

$$\boldsymbol{\dot{\gamma}_{annulus} = \frac{12\overline{v}}{d_o - d_i} + \frac{\tau_y}{2\mu_{pl}}} \quad \textbf{Eq. 6-18}$$

Power-Law Model

The Power-Law Model is another tool available to approximate the pseudoplastic behavior of fluids. In contrast to the Bingham Plastic model, it does not account for yield stress, but utilizes the flow behavior index and flow consistency index to describe flow behavior (Bourgoyne, 1986). The Power-Law model is defined by Eq. 6-19 (Skalle, 2012):

$$\boldsymbol{\tau = K|\dot{\gamma}|^{n}} \qquad \textbf{Eq. 6-19}$$

The Power-Law Model is dependent on the flow consistency index, K, and the flow-behavior index, n. The latter is given by Eq. 6-20 (Lapeyrouse, 2002):

$$\boldsymbol{n = \frac{\log\frac{\theta_{600}}{\theta_{300}}}{\log\frac{\dot{\gamma}_{600}}{\dot{\gamma}_{300}}} = \frac{\log\frac{\theta_{600}}{\theta_{300}}}{\log\frac{600}{300}} = \frac{\log\frac{\theta_{600}}{\theta_{300}}}{\log 2} = 3.32 * \log\frac{\theta_{600}}{\theta_{300}}} \qquad \textbf{Eq. 6-20}$$

$n > 1$ represents a dilatant fluid, $n = 1$ a Newtonian fluid, and $n < 1$ a pseudoplastic fluid. θ_i, used to calculate n (Eq. 6-20) and K (Eq. 6-21), refers to the viscometer dial readings, θ at *i* RPM.

The flow consistency index, K, is defined by Eq. 6-21 (Bourgoyne, 1986):

$$\boldsymbol{K = \frac{\tau_i}{\dot{\gamma_i}^{n}}} \qquad \textbf{Eq. 6-21}$$

If θ_{600} and θ_{300} viscometer dial readings are unknown, they may be obtained from the plastic viscosity and yield point as follows (Lapeyrouse, 2002):

$$\boldsymbol{\theta_{300} = \mu_{pl} + \tau_y} \qquad \textbf{Eq. 6-22}$$

$$\boldsymbol{\theta_{600} = \mu_{pl} + \theta_{300}} \qquad \textbf{Eq. 6-23}$$

The effective viscosity for pipe flow may be found by Eq. 6-24 (Skalle, 2012):

$$\boldsymbol{\mu_{eff,pipe} = \left(\frac{8\bar{v}}{d_h} * \frac{3n+1}{4n}\right)^{n} * \frac{Kd}{8\bar{v}}} \qquad \textbf{Eq. 6-24}$$

The corresponding effective viscosity for annular flow may be found by Eq. 6-25 (Skalle, 2012):

$$\boldsymbol{\mu_{eff,annulus} = \left(\frac{12\bar{v}}{d_h} * \frac{2n+1}{3n}\right)^{n} * \frac{Kd}{12\bar{v}}} \qquad \textbf{Eq. 6-25}$$

The shear rate for pipe flow is expressed by Eq. 6-26 (Skalle, 2012):

$$\boldsymbol{\dot{\gamma}_{pipe} = \frac{8\bar{v}}{d} * \frac{3n+1}{4n}} \qquad \textbf{Eq. 6-26}$$

And the corresponding shear rate for annular flow by Eq. 6-27 (Skalle, 2012):

$$\dot{\gamma}_{annulus} = \frac{12\bar{v}}{(d_o - d_i)} * \frac{3n+1}{4n} \qquad \textbf{Eq. 6-27}$$

Herschel-Bulkley Model

The last of the popular Non-Newtonian Models is the Herschel-Bulkley Model, also known as the Yield Power Law model. It is defined by Eq. 6-28 and combines the Bingham Plastic and the Power Law models. The model rests on the assumptions that the fluid is incompressible, and that the rheological parameters vs. pressure and temperature are constant.

$$\tau = \tau_y + K|\dot{\gamma}|^n \qquad \textbf{Eq. 6-28}$$

Many drilling fluids with additives behave according to Herschel-Bulkley Model, and it is widely utilized in the Oil & gas industry to model the hydraulics of drilling fluid. However, the iterative methods used are too complex to be included in this thesis, and will thus not be discussed in further detail.

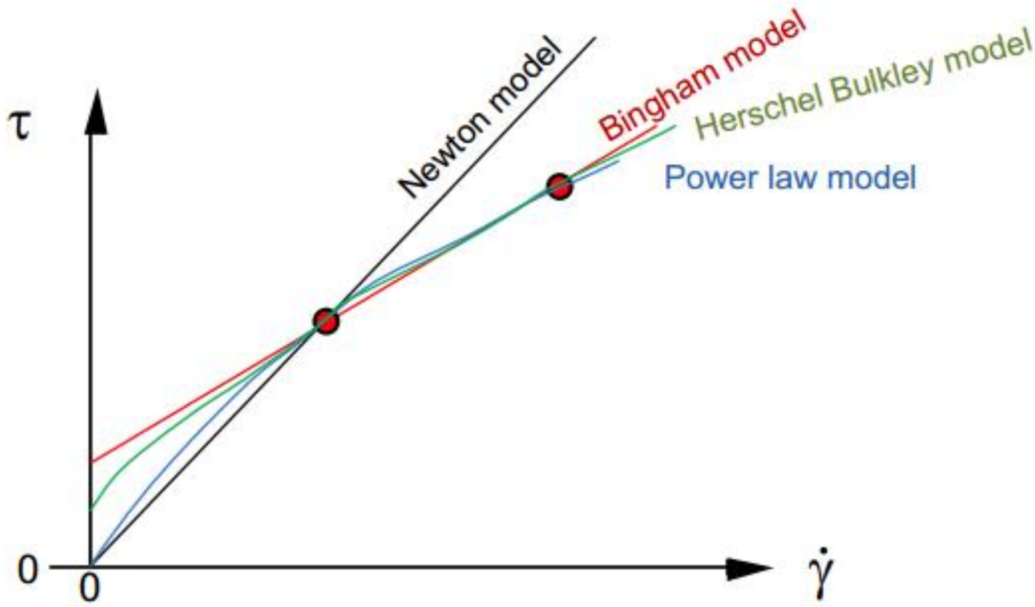

Figure 6-3: The flow curves of four different rheological models of four different fluid samples (Skalle, 2012)

6.1.3.3 Other Effects

Gel Effects

When circulation in the wellbore is halted, i.e. when the pumps are shut off, the drilling fluids have a tendency to settle, and establish a gelled structure. This is very much a time-dependent behavior. When the circulation is reinitialized, the gel structure has to be broken up by applying shear stress. This results in spikes in the BHP as the pumps go on-line, or the string is moved up or down in order to break up the gel structure. The magnitude of the gelling effect varies from fluid to fluid; it is often desirable for operators to add additives to the mud that will accelerate the gelling effect, since gelling delays solid settling, and may thus be a benefit w.r.t. wellbore cleaning (Skalle, 2012). This may be particularly beneficial in wells with long deviated sections with angle $< 60^0$, to prevent avalanching. However, since the calculations presented in the case study are based on the assumption that the fluids are constantly circulating, the gel effect will be ignored.

Temperature Fluctuations

It is assumed that the impact of temperature over time on the results is negligible. This is a simplification; liquid viscosity and yield stress of fluids, pressure wave propagation velocity, fluid state and density are all factors that are dependent on temperature (Stiff, 1970). Also, the additives may be affected, altering the fluids properties as a fluid is exposed to high temperatures over time. Quantifying the impact temperature fluctuations may have on this system lies beyond the scope of this thesis.

Pipe Eccentricity

It may be assumed that pressure drop due to friction in annular flow may, at least in part, be correlated to the area exposed to flow and the geometry of the flow area. While drilling, the position of the casing/liner will vary between the extreme positions (examples shown in Figure 6-4) and anywhere in between depending on well geometry, well trajectory, and drill string composition. Thus, the pressure profile of a wellbore annulus will be affected by the eccentricity of the inner pipe. Properly modelling the steady state wellbore hydraulics using the tools available for conventional calculations is a challenge, and borders on the insurmountable if transient conditions are taken into account. It is possible to simulate this behavior to some degree of accuracy using *Computational Fluid Dynamics* (CFD) (Dokhani, et al., 2013). Performing this kind of CFD simulations is beyond the scope of this thesis, however, and it will be assumed that the drill string and all of its components is perfectly centralized in the annulus.

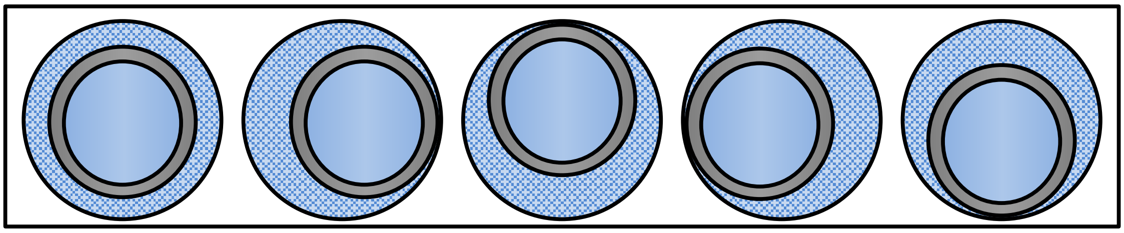

Figure 6-4: Eccentricity of inner pipe exemplified

Singularity Losses

As fluids flow over valves, bends, tees, tool joints, sudden expansions and contractions in the flow area, small pressure losses will accumulate. These kinds of minor losses, commonly referred to as singularity losses, are determined experimentally, and are largely dependent on geometry. Singularity losses over tool joints have been included in the calculations performed for the case studies presented in Chapter 7, using Eq. 6-29, Eq. 6-30 and Eq. 6-31 (Skalle, 2012):

$$\Delta p_{tool\,joints} = K_{L,contraction} * \frac{1}{2} * \rho * (\bar{v}^2) \qquad \text{Eq. 6-29}$$

where

$$K_{L,contraction} = 0.5 * K_{L,expansion} \qquad \text{Eq. 6-30}$$

and

$$K_{L,expansion} = \left(1 - \frac{A_1}{A_2}\right)^2 \qquad \text{Eq. 6-31}$$

Calculating singularity losses along the entire well to any degree of accuracy is a challenge that requires advanced tools like CFD to handle. The losses that are predictable are assumed to be fairly minor, and are mainly related to constrictions and expansions of the flow area where the diameter of the drill string changes. Uncertainties include cave outs, washouts, variations in wellbore diameter due to smoothness, and changes in wellbore trajectory due to tortuosity, to mention a few examples. Therefore, aside from the pressure losses related to tool joints, calculations on singularity losses will not be discussed or quantified in further detail.

6.1.3.4 Constraints

Flow Rate Restrictions

Retrievable CD/LD systems rely on BHA components such as RSS, MWD, LWD and PDM. Such components (RSS and PDM especially) are usually designed to operate within a given flow rate range. If the circulating flow rate exceeds the specifications the components may suffer damage or compromised functionality. The PDM will not be able to deliver sufficient power to the bit if the flow rate drops below the minimum flow rate specified, for example.

Wellbore Cleaning

In order to remove cuttings from the wellbore, the flow velocity has to be higher than the slip velocity of said cuttings. The slip velocity depends on the shape, density and size of the cuttings, as well as fluid parameters such as yield point, viscosity and density. Calculating accurate slip velocities, and associated pressure losses, for cuttings has been determined to lie beyond the scope of this thesis. Rather, it has been assumed that maintaining a flow velocity greater than $v = 0{,}8\ {}^{m}/_{s}$ in all sections of the well is sufficient for adequate wellbore cleaning (K&M Technologies, 2011). Since flow velocity is highly dependent upon flow rate and flow area, the hydraulic model has been set up to compare the flow velocities in each section with the largest annular area against this criterion.

Casing/Liner Rotation

Rotating the casing/liner while circulating may have some effect on the pressure drop along the casing/liner string. Any attempt at predicting the magnitude of this effect requires the use of CFD modelling tools, however. Thus, it lies beyond the scope of this thesis, and will not be discussed further.

6.1.4 Pressure Loss Equations

6.1.4.1 Laminar Flow

The following subchapter will describe the pressure losses, Δp, in pipe and annular flow for different types of fluids. These equations have been used to estimate the pressure losses that will occur during drilling with liner and casing, and demonstrate the advantages of combining these technologies with MPD in order to navigate through narrow mud windows.

The pressure losses for laminar pipe flows with Newtonian fluids, Bingham fluids and Power Law fluids are defined in Eq. 6-32, Eq. 6-33 and Eq. 6-34 (Skalle, 2012):

$$\Delta p_{pipe,Newtonian} = \frac{32 * \mu * \bar{v} * L}{d^2} \quad \textbf{Eq. 6-32}$$

$$\Delta p_{pipe,Bingham\ Plastic} = \frac{32 * \mu * \bar{v} * L}{d^2} + \frac{16 * L * \tau_y}{3d} \quad \textbf{Eq. 6-33}$$

$$\Delta p_{pipe,Power\ Law} = 4 * K \left(\frac{8\bar{v}}{d} * \frac{3n+1}{4n}\right)^n * \frac{L}{d} \quad \textbf{Eq. 6-34}$$

Annular flows are more challenging to model than pipe flows due to the more complex flow areas (see Figure 6-5).

Flow in between two concentric pipes can be treated either as flow in true concentric pipes, or in a simplified manner, as flow between two parallel plates. For narrow annuli the deviation between true and parallel flow is highest, and here the losses may become a large portion of total loss, significant errors are introduced (Skalle, 2012).

Other than a brief discussion on the significance of pipe eccentricity, the matter of flow area geometry in annular flows lies beyond the scope of this thesis, and will not be discussed in further detail. Equations for pressure loss estimation in annular flows for the respective fluid models are available in Eq. 6-35, Eq. 6-36 and Eq. 6-37 (Skalle, 2012).

$$\Delta p_{annulus,Newtonian} = \frac{48 * \mu * \bar{v} * L}{(d_o - d_i)^2} \quad \textbf{Eq. 6-35}$$

$$\Delta p_{annulus,Bingham\ Plastic} = \frac{48 * \mu_{pl} * \bar{v} * L}{(d_o - d_i)^2} + \frac{6 * L * \tau_y}{(d_o - d_i)} \quad \textbf{Eq. 6-36}$$

$$\Delta p_{annulus,Power\ Law} = 4 * K \left(\frac{12\bar{v}}{d_o - d_i} * \frac{2n+1}{3n}\right)^n * \frac{L}{d_o - d_i} \quad \textbf{Eq. 6-37}$$

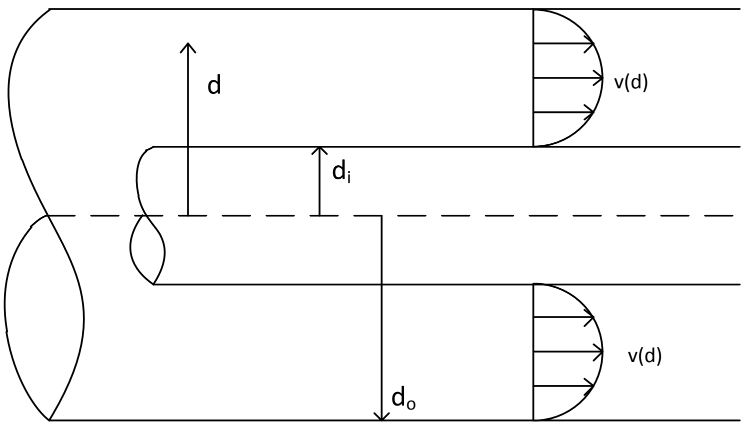

Figure 6-5: Annular Fluid Flow

6.1.4.2 Turbulent Flow

Eq. 6-38, Eq. 6-39 and Eq. 6-40 describes turbulent fluid behavior for Newtonian, Bingham Plastic and Power Law fluids, respectively (Skalle, 2012):

$$\Delta p_{annulus,Newtonian} = \frac{0.092\rho_{mix}{}^{0,8} * \bar{v}^{1,8} * \mu^{0,2} * L}{d_h{}^{1.2}} \quad \textbf{Eq. 6-38}$$

$$\Delta p_{annulus,Bingham\ Plastic} = \frac{0.073\rho_{mix}{}^{0,8} * \bar{v}^{1,8} * \mu^{0,2} * L}{d_h{}^{1.2}} \quad \textbf{Eq. 6-39}$$

$$\Delta p_{annulus,Power\ Law} = a_{Power\ Law} * N_{Re}{}^{-b} \frac{4L}{d_h} \rho \bar{v}^2 \quad \textbf{Eq. 6-40}$$

In order to calculate the pressure loss for Power Law fluids, some additional parameters are needed, namely $\boldsymbol{a_{Power\ Law}}$ (Eq. 6-41) and $\boldsymbol{b}$ (Eq. 6-42). The hydraulic diameter, $\boldsymbol{d_h}$, is expressed by equation Eq. 6-43.

$$a_{Power\ Law} = \frac{\log(n) + 3,93}{50} \quad \textbf{Eq. 6-41}$$

$$b = \frac{1,75 - \log(n)}{7} \quad \textbf{Eq. 6-42}$$

$$d_h = d_o - d_i \quad \textbf{Eq. 6-43}$$

6.2 Rock Mechanics

Fracture Pressure

In order to account for the reduced pore pressure associated with depletion, certain correlations have been included in this thesis in order to estimate the changes to the drilling window.

Eq. 6-44 describes the relationship between the major horizontal stress, σ_H, p_f^{frac}, and depletion (Fjær, et al., 2008):

$$\Delta\boldsymbol{\sigma_H} = \Delta\boldsymbol{p_f^{frac}} = \boldsymbol{\alpha}\frac{(\mathbf{1}-\mathbf{2}\boldsymbol{\nu})}{(\mathbf{1}-\boldsymbol{\nu})} * \boldsymbol{\Delta p_p} \quad \textbf{Eq. 6-44}$$

In this case, certain approximations have to be made, due to an incomplete dataset. The parameter α is called the Biot coefficient (Eq. 6-45) (Fjær, et al., 2008).

$$\boldsymbol{\alpha} = \mathbf{1} - \frac{\boldsymbol{K_{fr}}}{\boldsymbol{K_s}} \quad \textbf{Eq. 6-45}$$

In unconsolidated or weak rocks, α is close to 1 (Fjær, et al., 2008).

ν is an elastic parameter, known as Poisson's ratio. It is a measure of lateral expansion relative to longitudinal contraction (Eq. 6-46):

$$\boldsymbol{\nu} = -\frac{\boldsymbol{\varepsilon_y}}{\boldsymbol{\varepsilon_x}} \quad \textbf{Eq. 6-46}$$

ε_y and ε_x signifies elongation in the y and x-direction, respectively. For sandstones in general, the Poisson ratio is assumed to be ~0.3 (Fjær, et al., 2008). This will largely determine how the formation strength is affected by depletion, and a high Poisson Ratio may extend the mud window significantly.

$\Delta\boldsymbol{p_f^{frac}}$ will be calculated using the aforementioned formulae in order to account for depletion.

It is believed that the aforementioned Plastering Effect will serve to strengthen the borehole to some extent, thus extending the drilling window. This phenomenon is well documented through field observations and in core samples retrieved from wells drilled using CD/LD (Moellendick, et al., 2011). While conducting research for this thesis, no sources have been found that has made any attempt to quantify the magnitude of this effect. Thus, no assumptions have been made in this regard.

6.3 Well Trajectory

Calculating the well trajectory is necessary in order to determine the horizontal and vertical deviation of the well, and the resulting length of the well. This is used in order to determine the pressure losses occurring both as a result of gravity and friction. The *Minimum Curvature Method* (model shown in Figure 6-6) is the most common method used in the industry, and is the one used in calculating the trajectory of the well in question. The minimum curvature method is based on the assumption that the wellpath can be approximated using two asymptotic straight line segments. A ratio factor has to be applied in order to correct for bending between two stations of the wellpath (NTNU Course TPG4185, 2012).

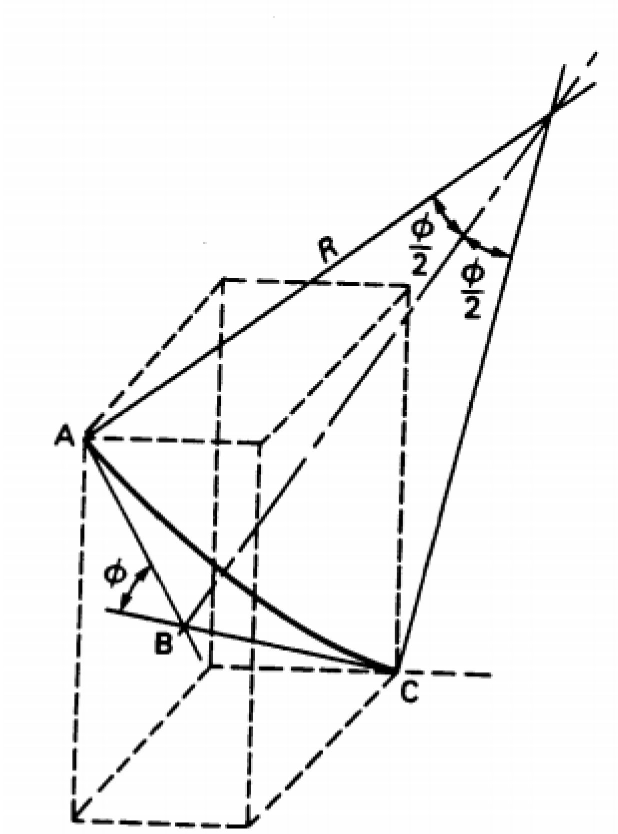

Figure 6-6: The minimum curvature model (Insert citation)

The *Dog Leg-Angle*, denoted $\boldsymbol{\varphi}$, describes the change in inclination between two stations, and is calculated by Eq. 6-47 (NTNU Course TPG4185, 2012):

$$\boldsymbol{\varphi = cos^{-1}(cos\alpha_1 * cos\alpha_2 + sin\alpha_1 * sin\alpha_2 * \cos(\beta_1 - \beta_2))} \quad \textbf{Eq. 6-47}$$

Where α_1 = angle at the start of a build-up section

α_2 = angle at the end of a build-up section

β_1 = azimuth at the start of a build-up section

β_2 = azimuth at the end of a build-up section

For the calculations performed in the case study, the azimuths $\beta_1$and β_2 will always be assumed to be zero, indicating that the directional sections of the well will all be drilled in the same compass direction. Eq. 6-47 will not actually be used in the calculations presented in the case study, as the well is plotted using the angle as a criteria for calculating well trajectories. Rather, the DLS will be used to calculate the length of the build-up section between two stations, L, by Eq. 6-48. This may then be used together with Eq. 6-49 to find the radius of the build section (NTNU Course TPG4185, 2012).

$$\boldsymbol{L = 30 * \frac{\varphi}{DLS}} \qquad \textbf{Eq. 6-48}$$

$$\boldsymbol{R = \frac{L*180}{\pi*\varphi}} \qquad \textbf{Eq. 6-49}$$

The ratio factor, $\boldsymbol{F}$, is calculated using Eq. 6-50:

$$\boldsymbol{F = \frac{2}{\varphi}\left(\frac{180}{\pi}\right) tan\left(\frac{\varphi}{2}\right)} \qquad \textbf{Eq. 6-50}$$

Eq. 6-51 is used to calculate the vertical displacement for each wellbore section, $\Delta\boldsymbol{V}$:

$$\Delta\boldsymbol{V} = \boldsymbol{F} * \frac{\boldsymbol{L}}{2} * (\boldsymbol{cos\alpha_1} + \boldsymbol{cos\alpha_2}) \qquad \textbf{Eq. 6-51}$$

Eq. 6-52 describes the horizontal displacement of an inclined section of a well in the northern direction, $\Delta\boldsymbol{N}$:

$$\Delta\boldsymbol{N} = \boldsymbol{F} * \frac{\boldsymbol{L}}{2} * (\boldsymbol{sin\alpha_1 cos\beta_1} + \boldsymbol{sin\alpha_2 cos\beta_2}) \qquad \textbf{Eq. 6-52}$$

Eq. 6-53 is used to calculate the horizontal displacement of an inclined section of a well in the eastern direction, $\Delta\boldsymbol{E}$:

$$\Delta\boldsymbol{E} = \boldsymbol{F} * \frac{\boldsymbol{L}}{2} * (\boldsymbol{sin\alpha_1 sin\beta_1} + \boldsymbol{sin\alpha_2 sin\beta_2}) \qquad \textbf{Eq. 6-53}$$

In the case study, Eq. 6-53 will not be used for the sake of simplicity, as the azimuths are both assumed to be zero (the sine of 0^o equals zero).

7 Case Study

7.1 Case Description

It was decided early on that the drilling methods described in this thesis are suitable for drilling through severely depleted reservoir zones, especially HPHT reservoirs, and that the effects should be demonstrated by performing a case study.

Most of the published data sets found while conducting research for this thesis were found to be incomplete or unsuitable. Eventually, it was decided to use data published by Statoil, on the Kristin field. Kristin a gas-condensate HPHT field found straddling block 6406 / 2 and 6506 /2, located in the south-west part of the Halten Bank in the Norwegian part of the North Sea. It is located at a water depth of 370 meters (Offshore Technology). For the purpose of this thesis, the upper reservoir has been set at 4162m. The field came online in 2005, and is, per 2014, assumed to have been depleted to such a degree that the drilling window has been completely closed. Nevertheless, the field has been chosen to demonstrate how MPCD may be applied.

The pore pressure and fracture curves have been extrapolated from a pore pressure and fracture gradient plot published by Statoil (shown in Figure 7-1), using a simple freeware program called Plot Digitizer. Plot Digitizer is a Java program used to digitize scanned plots of functional data, which is then converted into a table that can be imported into Microsoft Excel[15]. An example of the process along with digitized values is shown in Figure 7-2. In order to extrapolate the necessary data some assumptions were made which were loosely based on published data. These assumptions were then used to calibrate Plot Digitizer in order to retrieve the appropriate data. The top of the upper reservoir was assumed to be situated at 4162m TVD below the sea floor, and the mud weight was assumed to be 2,15SG (Cesium Formate).

The data was cleaned up by deleting deviating points, and inserted into the hydraulic model. A basic guide to how the model should be used can be found in Appendix G. The resulting pressure regime can be seen in Figure 7-3. Basic rock mechanic correlations were used to simulate depletion of the reservoir, an example of which can be seen in Figure 7-4.

[15] **Sourceforge.** Plot Digitizer. *Sourceforge Web site.* [Online] [Cited: May 6, 2014.] http://plotdigitizer.sourceforge.net/

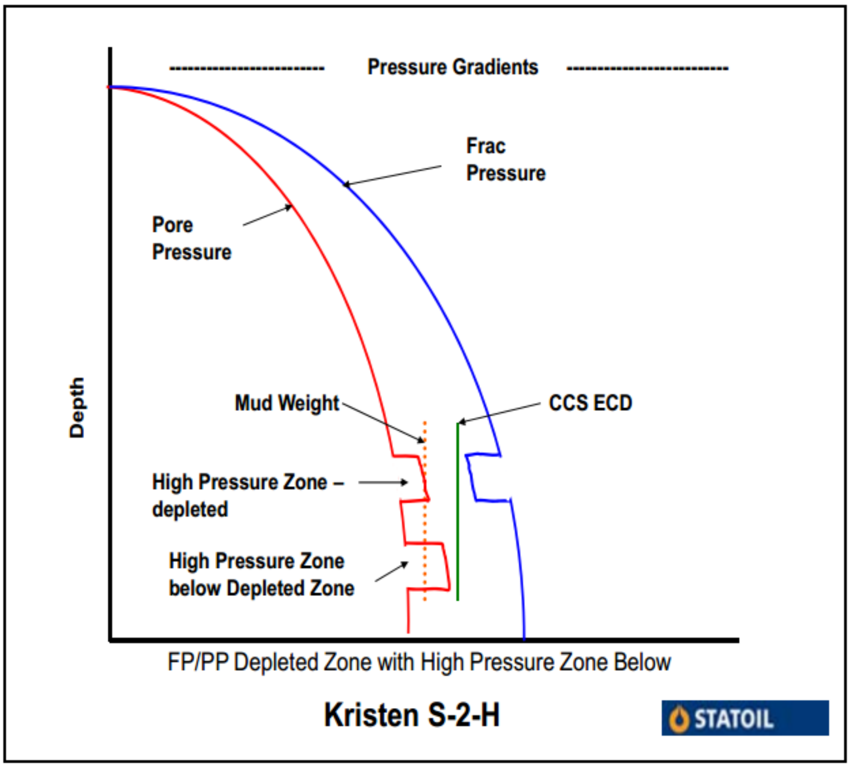

Figure 7-1: Kristin Pore Pressure and Fracture Gradient plot (Statoil)

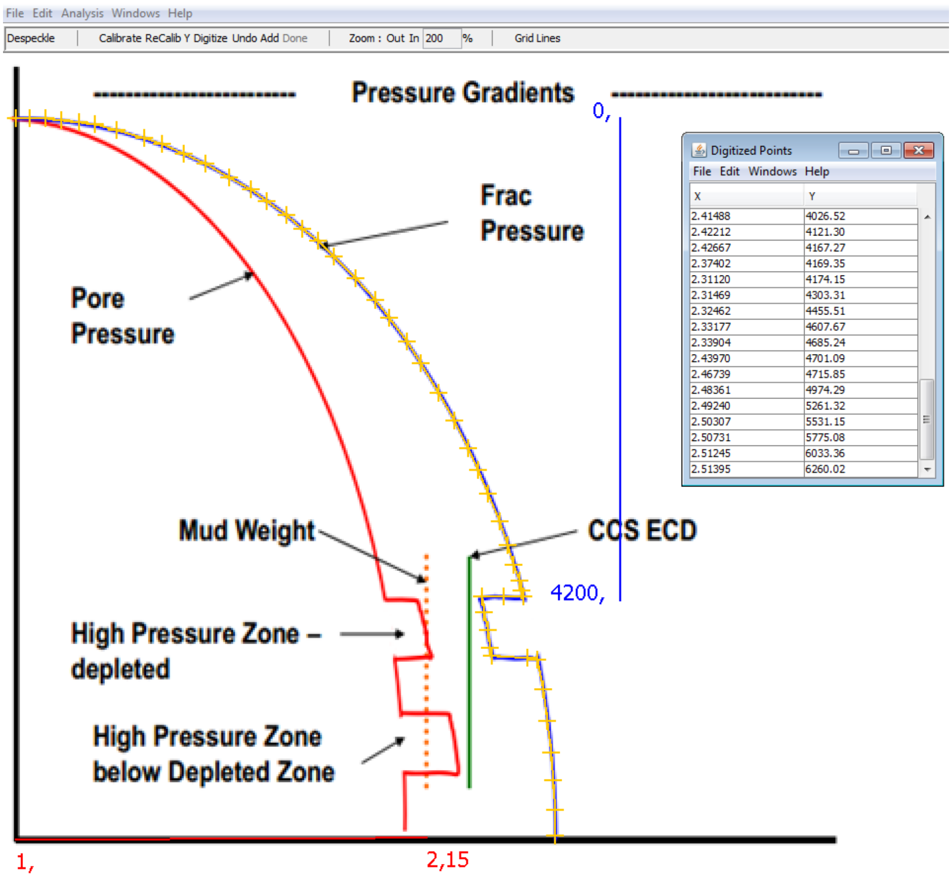

Figure 7-2: Example of digitized plot using Plot Digitizer

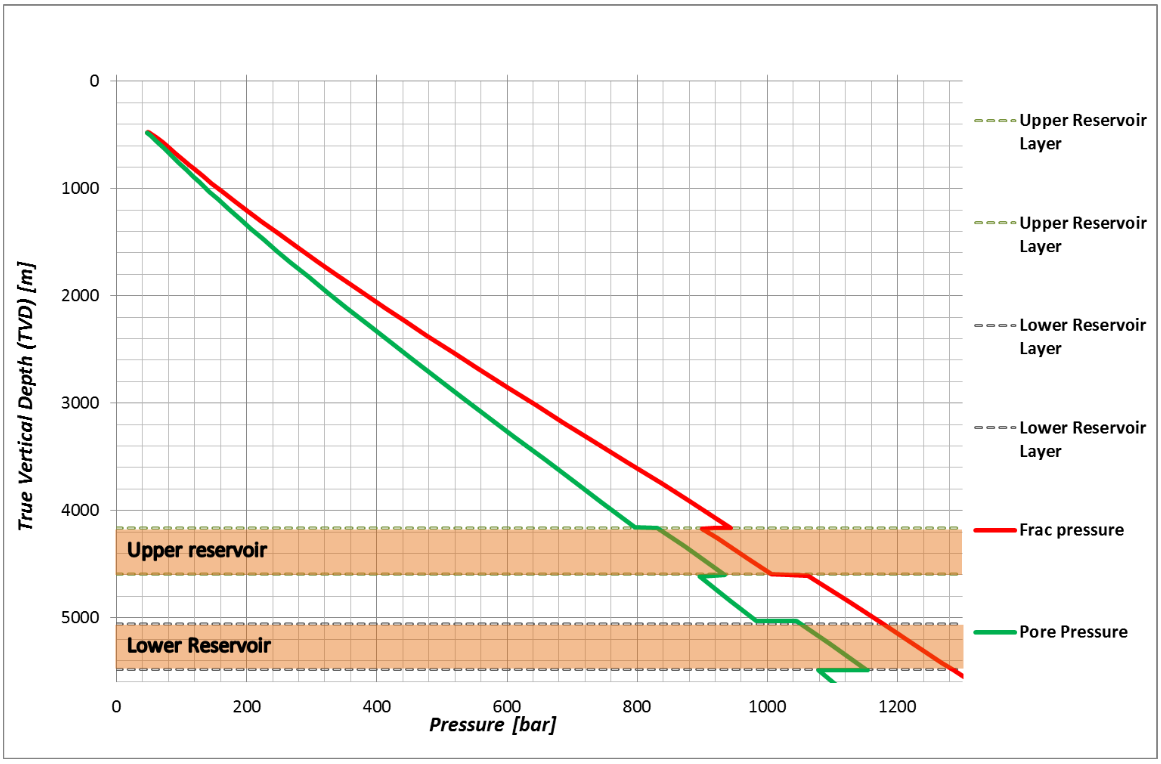

Figure 7-3: The pressure regime of the formation in question

7.2 Assumptions

In lieu of adequate data, the pore pressure was reduced by 160bar in the upper reservoir. The associated reduction in fracture pressure was computed using equations listed in Chapter 6.2. The intention is to simulate depletion of the upper reservoir. The resulting pressure regime is shown in Figure 7-4. Certain assumptions have been made in order to compute these values:

- Biot's coefficient was assumed to be 0.95
- The Poisson ratio was assumed to be 0.3
- The upper reservoir starts at 4162m TVD, and ends at 4594m TVD. It is assumed to be homogeneous, perfectly horizontal and flat, with a uniform thickness
- The lower reservoir starts at 5030m TVD and ends at 5485m TVD. It is assumed to be homogeneous, perfectly horizontal and flat, with a uniform thickness

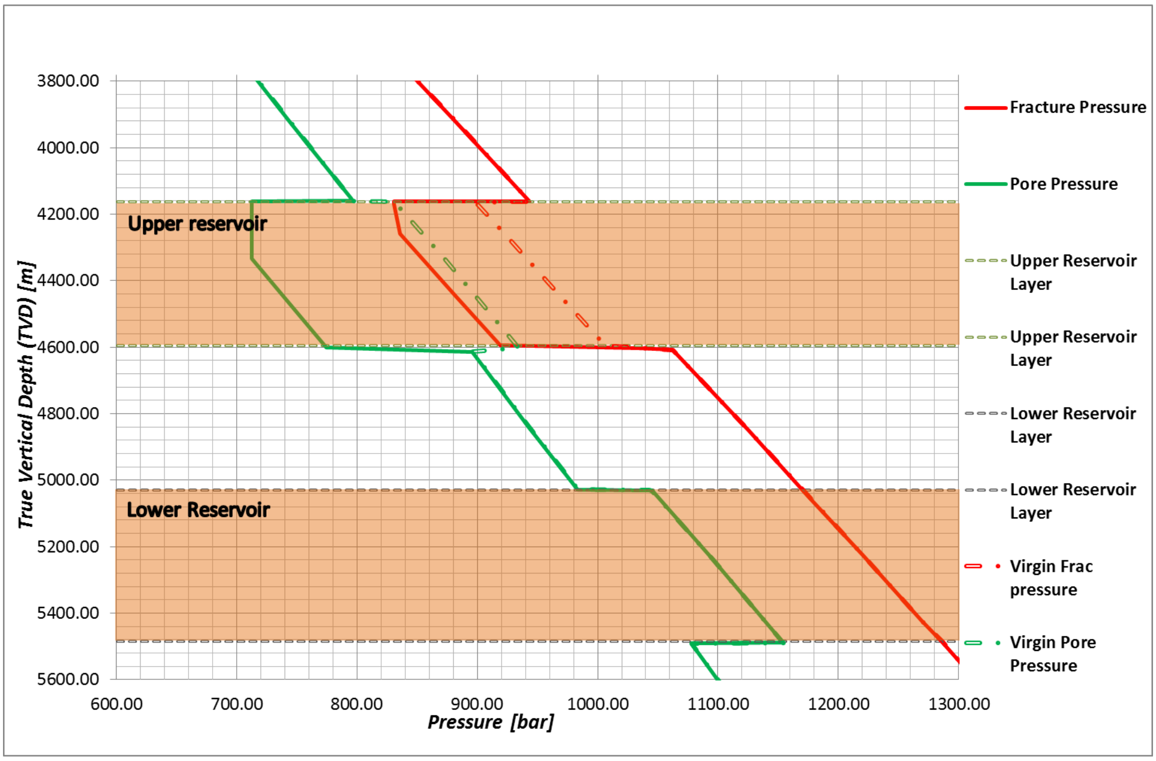

Figure 7-4: The pressure regime after 160 bar depletion

Figure 7-5 shows the wellbore trajectory used to compute the pressure losses along the wellbore. The well has been designed so that it is drillable using the MPCD technique due to the challenging pressure regime of the reservoirs. It was also decided that this was the most appropriate way to make a basis of comparison between the different techniques.

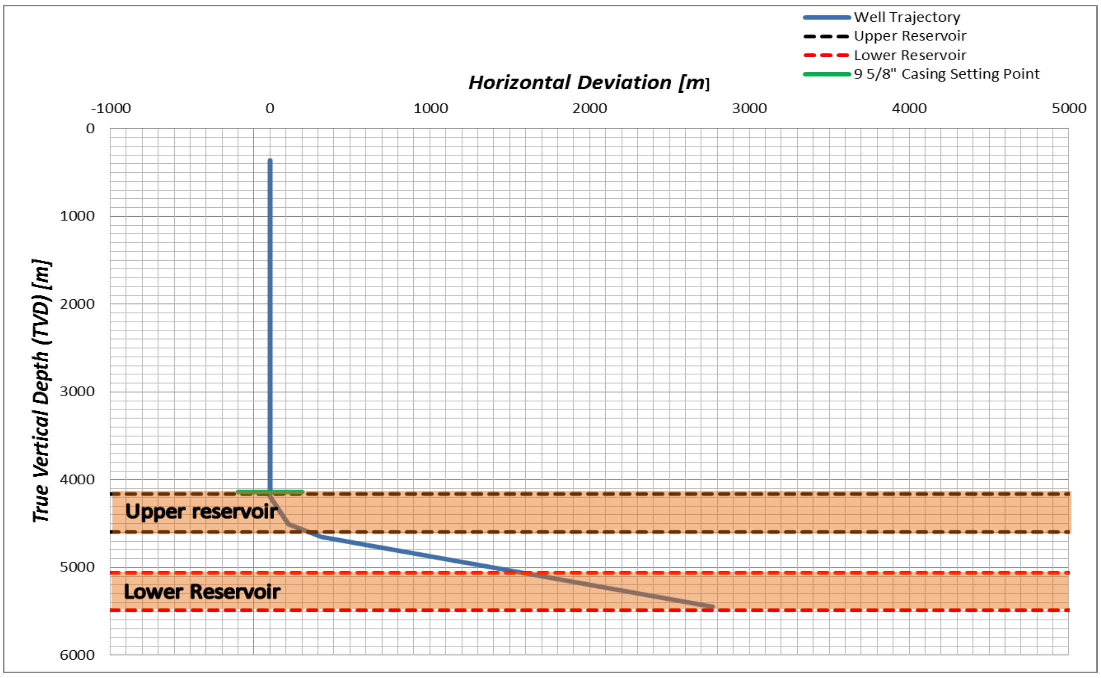

Figure 7-5: Wellbore trajectory, Case 1

The following assumptions have been made in order to compute the pressure losses along the well:

- The density of the cuttings of both overburden rock, reservoir rock and the rock of the intermediate interval is assumed to have a uniform density of ρ = 2700 kg/m^3
- The input parameters were changed to reflect drilling operations using other techniques (OBD, LD, MPD). Apart from altering the mud weight in cases, all other parameters are identical. Supplementary tables can be found in Appendix F.
- The fluid models used are assumed to be valid
- The ROP is assumed to be constant at 30 m/hr
- In order to maintain sufficient wellbore cleaning, the minimum fluid velocity is assumed to be v = 0.8 m/s
- Solids distribution is assumed to be perfectly homogenous along the wellbore
- Pressure effects caused by suspended and transported solids, pipe rotation, wellbore tortuosity, changes in wellbore geometry, temperature fluctuations, and more is assumed to be negligible
- The fluids are assumed to behave according to the Bingham Plastic rheology model
- The flows are assumed to be laminar in nature when Re < 2100, and turbulent if Re > 2100
- Safety margins of 1% for MPD techniques and 5% for OBD techniques are assumed to be sufficient

7.3 Results

7.3.1 Overbalanced Drilling

Figure 7-6 shows the pressure regime resulting from drilling the well in overbalance. Supplementary information is shown in Table 17 in Appendix F. When drilling in overbalance, the static mud weight must be higher than the pore pressure, in order to contain the reservoir fluids while making connections. Though the mud weight may allow drilling through the reservoir, the predicted ECD exceeds the fracture pressure of the formation from the moment entering the reservoir. Drilling into such a situation may lead to severe loss situations, which in turn may lead to kicks if the driller is unable to compensate for the lost fluids. Though it is possible to drill wells while taking losses, doing so on a consistent basis is not advisable. The productivity of the upper reservoir (which is still producing in this case) is likely to suffer as a result due to fluid loss and fracturing, and it seems likely that the drilling process may be slowed down by stuck pipe issues and other operational challenges. In the worst possible scenario, drilling with losses may lead to kick/loss cycles, and lead to a blowout.

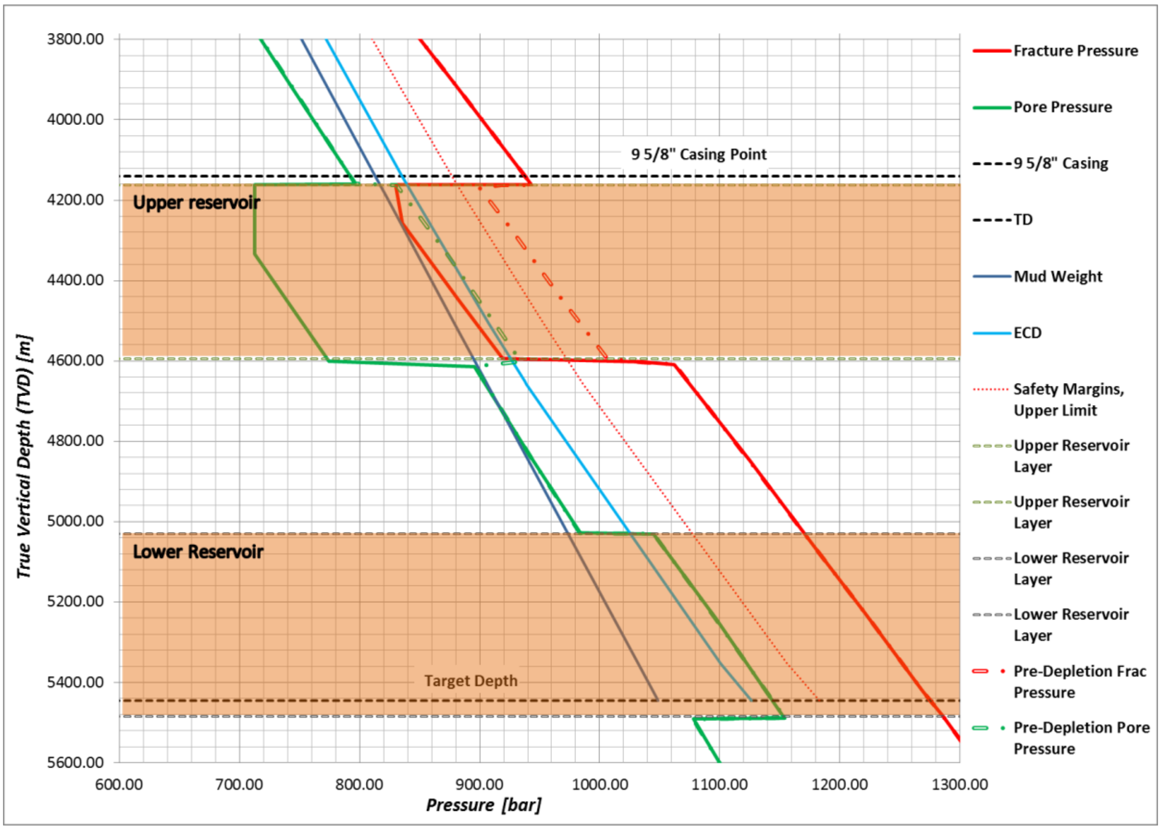

Figure 7-6: Wellbore pressure profile – drilling in Overbalance

7.3.2 Liner Drilling

Figure 7-7 shows the pressure regime resulting from drilling with liner. Supplementary information is shown in Table 18 in Appendix F. In this case, as with drilling using OBD, the ECD causes the wellbore pressure to exceed the fracture pressure of the formation from the moment of entering the reservoir, with very similar consequences as those outlined above. Though the plastering effect may increase the fracture strength of the formation, and thus mitigate fluid losses, the conditions under which plastering occurs are not well understood. The 5% safety margin exceeds the fracture pressure of the upper reservoir to the magnitude of ~80bar. It is highly probable that this would lead to serious losses: Drilling cannot be recommended in this case. The mud window is simply too narrow.

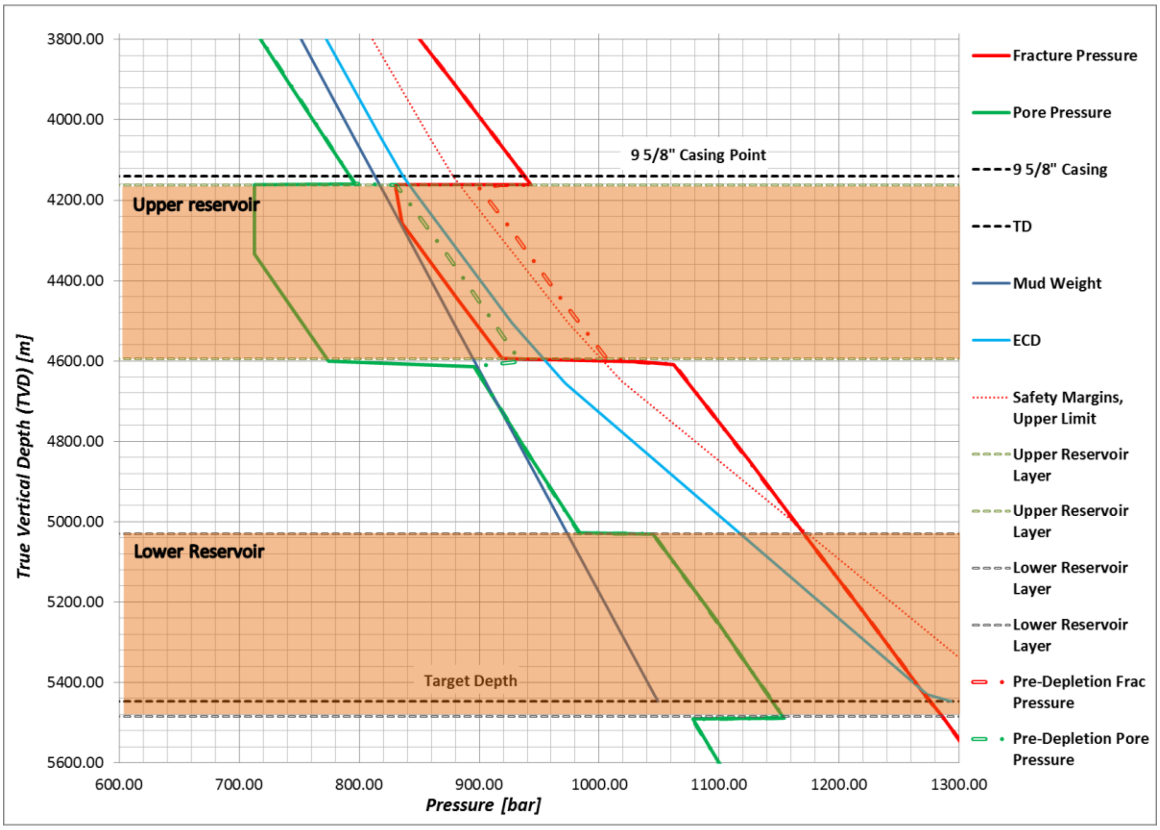

Figure 7-7: Wellbore pressure profile – drilling using Liner Drilling

7.3.3 Managed Pressure Drilling

Figure 7-8 shows the pressure profile resulting from drilling the well at balance (MPD). Supplementary information is shown in Table 19 in Appendix F. Contrary to the two previous examples, drilling through the upper reservoir seems possible to accomplish without encountering losses. There is no need to remain in static overbalance, thus it may be possible to drill safely through the reservoir while remaining within the drilling window by exploiting the ECD and backpressure. The pressure is maintained while making connections by utilizing a continuous circulating device, as described in Chapter 3. Once the reservoir has been drilled through, the driller has to POOH and set a casing or liner; there seems to be a serious risk of entering an underbalanced state if drilling proceeds. Thus, it is not safe to drill further.

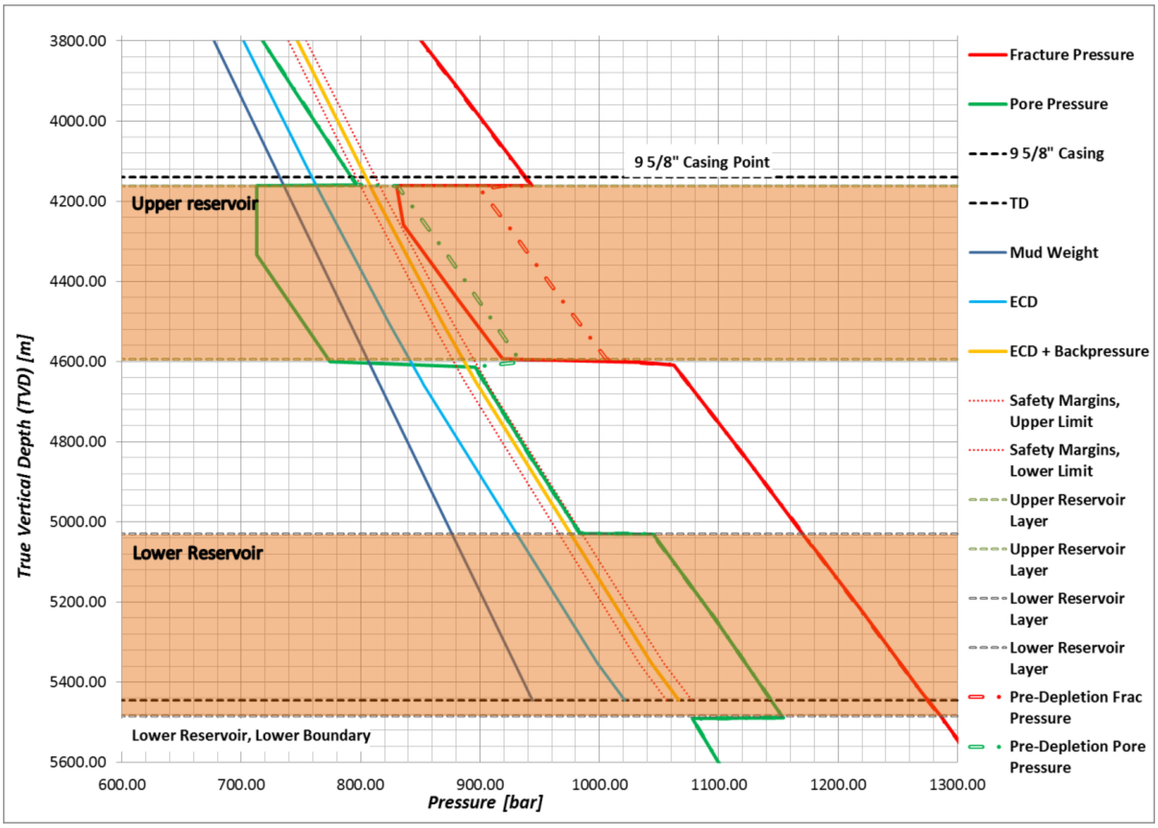

Figure 7-8: Wellbore pressure profile – drilling using MPD

7.3.4 Managed Pressure Casing Drilling

Figure 7-9 shows the wellbore pressure profile resulting from drilling using the MPCD technique described in this thesis. Supplementary information is shown in Table 20 in Appendix F. The figure shows that the wellbore pressure stays within the mud window throughout the entire interval. Thus, it may be possible to drill through both reservoirs in one trip.

The likelihood of being able to drill such a well without encountering stuck pipe incidents or other critical issues is very small, however. As can be seen in Table 20, the liner string is 3167m long, and the drilled interval is more than 3200m long. In general, it is not advisable to plan well sections longer than 1500-2000m when using liner drilling[16]. The restrictions are mainly related to torque and drag issues, but also the amount of time the wellbore is exposed to fluids and varying pressure regimes. As time passes, the probability of well control problems or stuck pipe issues occurring increases.

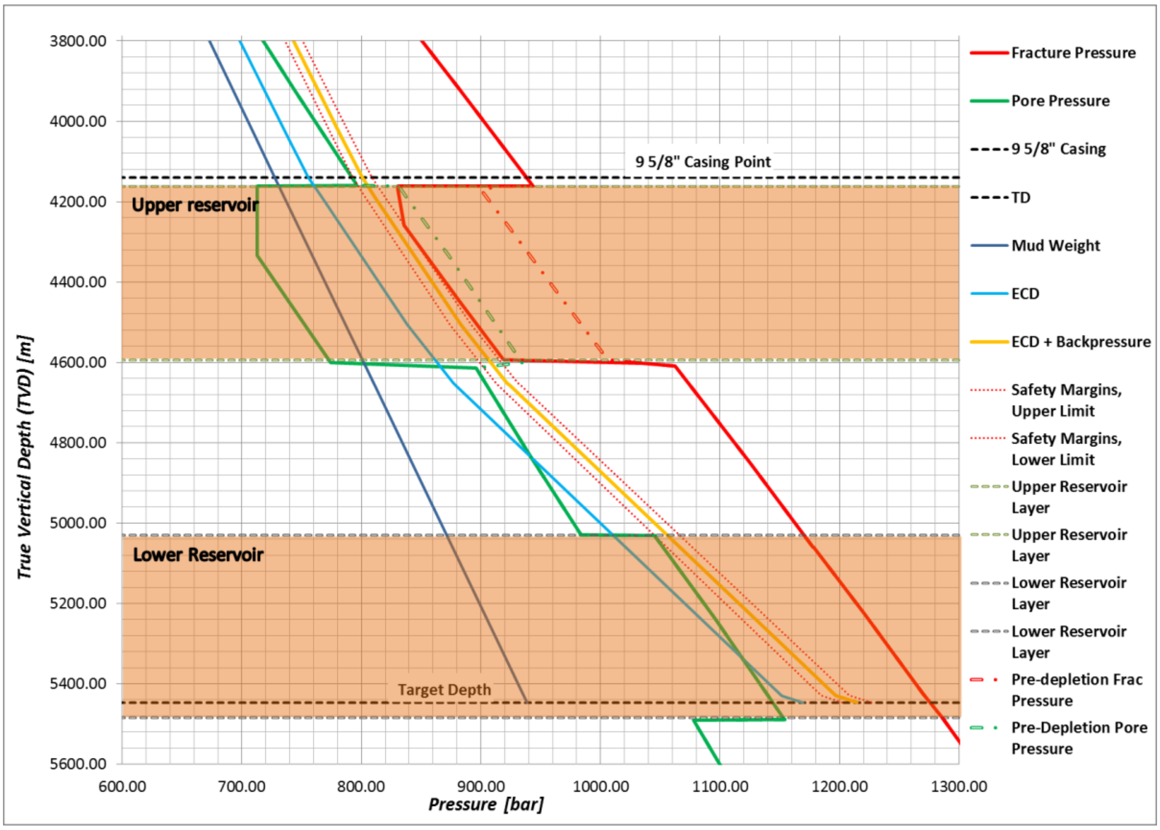

Figure 7-9: Wellbore pressure profile – drilling using MPCD

[16] Conversation with Jafar Abdollahi, 16th of May, 2014

7.4 Discussion

It has been mentioned that these results are based on several assumptions. The validity of these assumptions may be subjected to scrutiny, and rightly so. Making such assumptions was considered vital, however; going deeper into the matter lies beyond the scope of this thesis.

The field consists of:

- A depleted layer with a very narrow mud window
- Consecutive layers with very different pore pressure regimes (high pore gradient)

All of which were stipulated as being particularly challenging and of interest in the introduction chapter.

These results give clear indications as to the potential of the method: That MPCD can be used to solve the challenges mentioned, by exploiting the AFP, and maintaining precise control of the BHP in the process. Using the method may also increase the profitability of certain drilling operations being performed today by reducing drilling expenditures. Making attempts to quantify this potential gain is a matter for further research, however.

8 Discussion

8.1 Combining MPD and LD/CD

Combining complementary technologies may result in a system that is greater than the sum of its parts, preserving each technology's unique advantages while eliminating some of their weaknesses. Many of the conventional drilling problems still remain while using CD/LD. In fact, many of them are aggravated by the narrow annular clearance, and the impact this has on ECD, stuck pipe issues and formation ballooning. In addition, the ROP is likely to be reduced as well, due to increased chip hold-down pressures. MPD with drillpipe also suffers from some of the same challenges as conventional drilling; the ability to generate ECD is limited by pumping capacity and flow rate restrictions of BHA components (Stone, et al., 2006). When drilling in overbalance, ECD may be more of an issue than a benefit as it reduces the available mud window due to the requirement of maintaining static overbalance. When drilling at balance, the ECD may be exploited to increase the BHP without affecting the uphole wellbore pressure. Using pumps that are able to generate sufficient pressure is critical in order to achieve this goal.

Figure 3-5 shows operating procedures for a Weatherford RCD. In order to maintain a good seal while drilling with liner, the sealing "spear" must be stabbed in after the liner have passed. In the case of Casing Drilling, the RCD must be redesigned in order to maintain a seal around the casing string at all times. It is likely that the increased size of the casing would cause extra wear on the seal. This is likely not an issue if drilling using a drilling liner, as the sealing spear is, in most cases, stabbed in after the liner has passed the RCD and BOP. This depends on the MD of the well, and the length of the well section that is planned.

Perhaps the biggest challenges the Operator has to face when using CD/LD are the associated AFP and increased torque resulting from rotating the string. AFP is deemed an issue if it is a requirement to remain in static overbalance, as care must be taken not to exceed the formation's fracture pressure. If LD/CD is combined with MPD, it is possible to maintain a static underbalance while actively using the increased AFP to remain at balance in lower wellbore section while keeping the uphole wellbore pressure below the fracture gradient. While doing this, however, there is a risk of washing out poorly consolidated formations, as the AFP is largely determined by flow velocity, and this trait may incentivize higher flow rates. Drilling operations conducted using MPCD techniques is likely to reduce overbalance issues conventionally associated with CD/LD, such as wellbore ballooning/breathing and differential sticking. This may allow the driller to navigate very narrow mud windows while reducing mud costs at the same time[17]. This is exemplified further in the case study.

Thus far, it is obviously beneficial to maintain circulation at all times in order to utilize MPCD to its full potential. When the casing/liner is at target depth, the back pressure may be increased to compensate for the loss of ECD as the circulation system is disconnected in order to prepare for cementing and the inner string is POOH. A caveat is that increasing backpressure will increase the pressure uniformly along the wellbore. A possible consequence is that the uphole pressure, which was so carefully maintained below the fracture limit while drilling, may increase past the fracture limit, leading to losses.

Continuous pumping is critical to maintaining a stable ECD: Auxiliary pumps are needed in case of pump failure while drilling. Drilling with MPCD relies on maintaining a high ECD at any point in time during drilling.

Figure 8-1 shows an overview of how a depleted HPHT reservoir such as that shown in Figure 7-1 may be penetrated using current and future methods. It is assumed that the upper reservoir is heavily depleted, but is still drillable using conventional methods.

Option 1: The well is drilled conventionally, and a casing point is set above the upper reservoir (often 9 5/8" casing). The next interval (in this case 7") is then drilled until losses are encountered or the zone has been penetrated. The upper reservoir is then drilled using a 6" openhole solution.

Option 2: The upper reservoir is penetrated initially using Liner Drilling using 9 5/8" liner. Conventional drilling is used to drill through the reservoir layer and into the shale, and 7" casing is set. From there on, the well is drilled through the intermediate shale layer and lower reservoir using conventional drilling, and completed with an openhole solution.

Option 3: The reservoir is penetrated initially using Liner Drilling with 9 5/8" liner, setting the casing point inside the upper reservoir. MPCD is then used to drill through the upper reservoir, the intermediate shale layer, and the lower reservoir.

Option 4: MPCD with 9 5/8" liner is used to drill through the overburden, upper reservoir and into the intermediate shale layer. The well may then be drilled conventionally through the intermediate shale layer and into the lower reservoir using 8 ½" casing.

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[17] Since designer muds are often used to achieve specific fluid properties

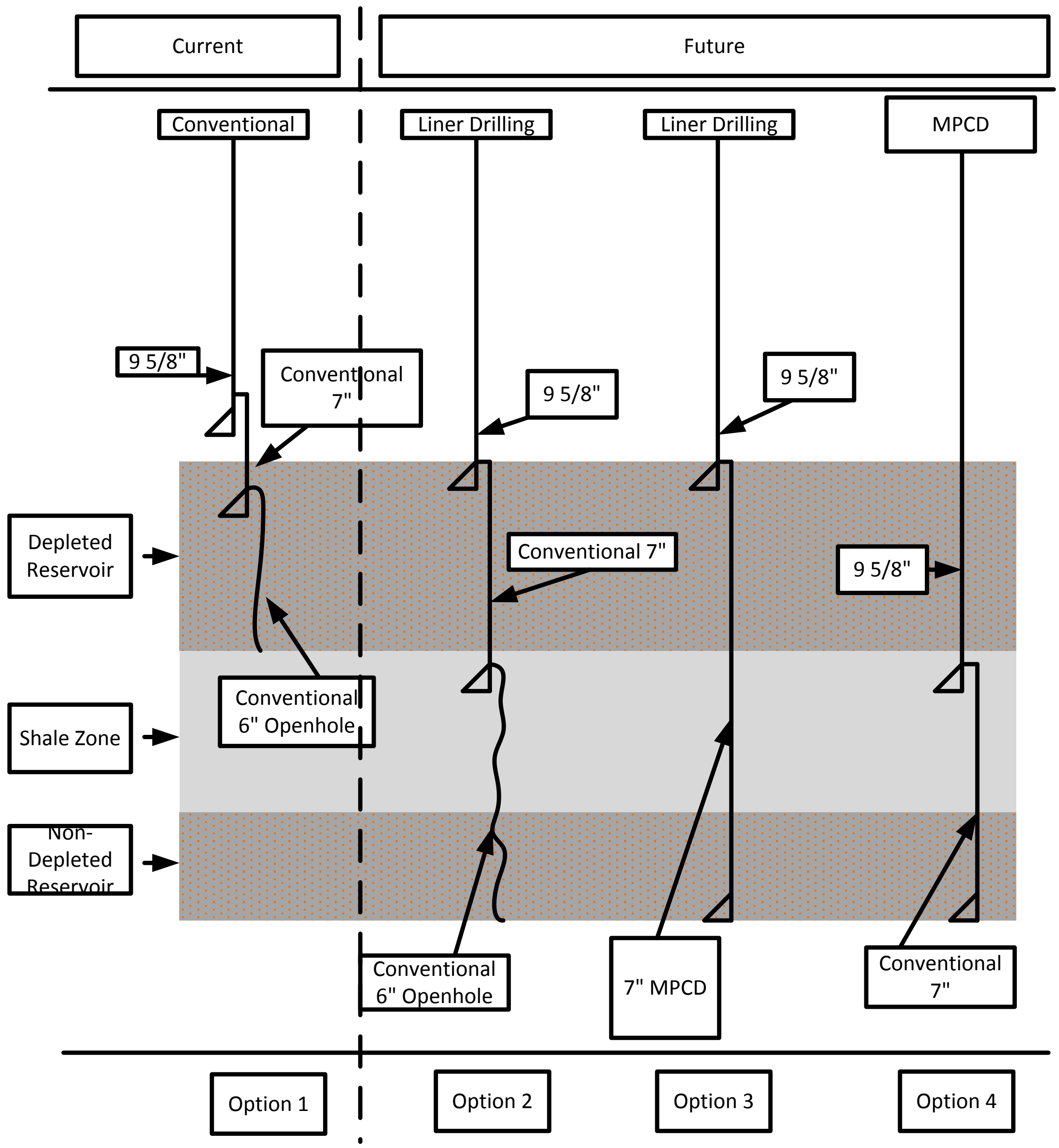

Figure 8-1: Drilling procedures using the different methods

Out of the four options, Options 3 and 4 are far superior. Fewer well sections are drilled, and the diameters of the producing intervals are higher. Of these, Option 4 seems preferable, as the diameter of the well section penetrating the depleted zone is higher than in Option 3, yielding greater productivity.

8.2 Managed Pressure Casing Drilling and Supporting Technologies

Using liner or casing in place of drill pipe in the drill string carries certain disadvantages which are not mitigated by using MPCD; so far it seems reasonable to assume that the pressure regime in the annulus surrounding the casing/liner is somewhat erratic and unpredictable. Local deviations in wellbore geometry and symmetry may potentially have a significant impact on the pressure losses for example. Therefore, it seems as though this method may benefit significantly from additional pressure monitoring, which may be achieved by improving communications with the BHA. This may be achieved using WDP, as described in Chapter 5. For systems that use a continuous inner string, communications with BHA may be improved greatly. The benefit of using pressure monitoring nodes distributed along with the signal booster subs along the string would be negated to some degree; these are dimensioned to work with drill string, not LD/CD.

ASM and SWD are not currently available in the liner part of the drill string. The casing/liner is exposed to so much abrasive wear and stress that it is very likely that the equipment would be damaged or rendered useless shortly after being exposed to open formation during drilling. ASM would still be available when using LD, from just above the liner interval and further up the string. This would be useful in order to quantify the total pressure losses over the liner string.

9 Conclusion

The main purpose of this thesis was to evaluate the possible benefits and limitations related to using MPD and CD/LD methods separately, and if they may be combined and used to open up new opportunities to develop particularly challenging oil and gas fields.

Managed Pressure Casing Drilling

- MPD and CD/LD are complementary technologies, and can be combined, provided modifications are made to certain pieces of equipment to accommodate the closed loop and bigger diameter string.
- The findings in this thesis indicate that using MPCD can be advantageous, provided careful candidate selection. In particular, the method seems well suited to drilling wells with very challenging pore pressure regimes, such as layered reservoirs with different pore pressures and heavily depleted reservoirs. This is supported by the case study

The advantages of MPD and CD/LD are well known. It is indicated that combining the two yields additional benefits, while preserving the individual benefits of the two separate technologies:

- Drilling with liner or casing in static underbalance, along with precise pressure management, may turn the increased AFP into an advantage in some situations
- Reduced overbalance reduces ROP, stuck pipe, and formation damage concerns usually associated with CD/LD
- Reduces heave induced surge & swab pressure fluctuations when drilling ahead from floaters

Hydraulic Model

- The hydraulic model was built and applied successfully. It is generalized, apart from a few parameters concerning the depths of reservoir layers and casing points, and can be used as a learning tool, and/or for the initial evaluation of pressure losses along a well.

Case Study

- The findings in the case study indicate that MPCD is an enabling technology. Though the well design used in the case study is prohibitively long, the well likely can't be drilled without encountering fluid losses or fluid influx, or without severe well tapering, using any of the other stipulated alternatives.

Concept Study: Expandable Tubular Drilling

- ETD may enable drilling of monobore wells
- Initial evaluation suggests that there is potential for reducing well construction costs, and increasing productivity of the final product by using ETD.
- The evaluation suggests that top-down expansion using a retrievable BHA mounted rotary expansion tool may be beneficial compared to the stipulated alternatives.

9.1 Future Work

Managed Pressure Casing Drilling

- Further studies should be made in order to understand the impact of combining the methods. Suggestions include:
    - Evaluate whether adding MPD to the equation has any impact on the torque and drag, and if it enables drilling longer well sections than would be possible without it.
    - Evaluate systems and equipment modifications required to accommodate MPCD
- Further attempts to quantify the benefits of combining technologies should be made. In order to do this, it is suggested that:
    - Statistics should be gathered from *End of Well Reports* (EOWR) from wells that have been drilled in conditions that would make them good candidates for MPCD. Interesting parameters include problems encountered, why drilling was successful/ why it was not, time spent, cost of consumables, and more.
    - Construct realistic scenarios using MPCD based on EOWRs, evaluate and quantify time spent on drilling the wells, and compare to statistics. Evaluate expenditures.
- The significance of the smear effect should be studied further, with special emphasis on whether the decreased pressure differential resulting from combining CD/LD with MPD will affect the phenomenon
- Model surge and swab as a result from heave (floaters) when using casing/liner in the drill string, and develop models for MPD systems that may be used to counteract the resulting pressure fluctuations.
- Use CFD to model the pressure losses resulting from the reduced annular flow area along the string, and incorporate findings into hydraulic models used for automatic MPD systems. Impact of pipe rotation should also be incorporated.
- Evaluate formation damage resulting from using MPCD compared to CD/LD and MPD.
    - Further studies into the effect of smearing and reduced overbalance on fluid and particle invasion and clay swelling should be made.
- Redesign RCD and CCS in order to allow for the use of CD/LD

Wired Drill Pipe

- Evaluate possibility of fitting conductor cables and induction coils, along with battery subs and pressure sensors to tubulars

Hydraulic Model

- The hydraulic model could be developed further in and of itself, or as a part of a greater model.
    - Other pressure related effects could be implemented, such as cuttings related pressure losses, the effect of pipe rotation, transient effects and more
    - Accommodations for the Herschel Bulkley model can be made

Expandable drilling liner

- Evaluate burst and collapse parameters in order to determine if it is advisable to use expandable tubulars in drilling applications by using FEM.
- Evaluate wear and fatigue parameters in order to determine whether the current expandable tubulars can be used for drilling applications
- Design expansion tools for use in the BHA

10 Conversion Table

Measurement	S.I. Unit	Field Unit	Conversion Factor
Distance	m	ft	1 m = 3.28084 ft
Diameter	m	in	1 m = 39.3701 in.
Pressure	Pa	psi	1 Pa = 0.000145037738 psi
Weight	kg	lbs	1 kg = 2.20462 pounds
Acceleration	m/s^2	ft/s^2	1 m/s^2 = 3.28084 ft/s^2
Flow Rate	m^3/s	GPM	1 m^3/s = 15852 GPM
Viscosity	Pa*s	cP	1 Pa*s = 1000cP
Density	kg/m^3	lbm/ft^3	1 kg/m^3 = 0.0624279606 lbm/ft^3

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Appendix A

Table 12: Rig rate overview on the NCS, all prices in USD/d (Offshore Media Group, 2013)

Name	Owner	Customer	Contract to	Semisubmersible	Drillship	Jack-up
Bideford Dolphin	Dolphin	Statoil	jan.17	418000		
Borgland Dolphin	Dolphin	Rig Manag. No.	jan.17	530000		
Bredford Dolphin	Dolphin	Lundin	may.16	442000		
COSLInnovator	COSL Drilling Euro	Statoil	jun.20	335000		
COSLPioneer	COSL Drilling Euro	Statoil	aug.14	320000		
COSLPromoter	COSL Drilling Euro	Statoil	jun.20	335000		
Deepsea Atlantic	Odfjell Drilling	Statoil	aug.14	490000		
Deepsea Bergen	Odfjell Drilling	Statoil	jun.17	339000		
Island Innovator	Island Offshore	Lundin	mar.15	Private		
Leiv Eriksson	Ocean Rig	Rig Manag. No.	mar.16	545000		
Maersk Giant	Maersk Drilling	Talisman	aug.14			private
Maersk Guardian	Maersk Drilling	Lundin	jun.14			private
Maersk Innovator	Maersk Drilling	ConocoPhilips	mar.17			private
Maersk Inspirer	Maersk Drilling	Statoil	okt.14			private
Maersk Gallant	Maersk Drilling	ConocoPhilips/Statoil	jun.16			312000
Ocean Vanguard	Diamond	Statoil	apr.15	354000		
Polar Pioneer	Transocean	Statoil	mai.14	519000		
Rowan Gorilla VI	Rowan Drilling	ConocoPhilips	jul.17			350000
Rowan Norway	Rowan Drilling	ConocoPhilips	jul.16			350000
Rowan Stavanger	Rowan Drilling	Talisman/Lundin	feb.14			350000
Scarabeo 5	Saipem	Statoil	sep.17	399000		
Scarabeo 8	Saipem	ENI Norge	jul.17	460000		
Songa Dee	Songa Offshore	Statoil	jul.16	423000		
Songa Delta	Songa Offshore	Statoil	jul.16	448000		
Songa Enabler	Songa Offshore	Statoil	sep.23	450000		
Songa Encourage	Songa Offshore	Statoil	jul.23	450000		
Songa Endurance	Songa Offshore	Statoil	feb.23	428000		
Songa Equinox	Songa Offshore	Statoil	nov.22	428000		
Songa Trym	Songa Offshore	Statoil	jul.15	365000		
Statoil Cat J1+2	TBA	Statoil	mar.24			private
Stena Don	Stena Drilling	Statoil	mar.17	400000		
Transocean Arctic	Transocean	Statoil	aug.15	418000		
Transocean Barents	Transocean	Det norske	jun.14	570000		
Transocean Leader	Transocean	Statoil	apr.15	409000		
Transocean Searcher	Transocean	BG	jun.15	394000		
Transocean Spitsbergen	Transocean	Statoil	jul.15	500000		
Transocean Winner	Transocean	Lundin/Marathon	jan.15	487000		
West Alpha	Seadrill	ExxonMobil	apr.16	476000		
West Elara	Seadrill	Statoil	apr.17			358000
West Epsilon	Seadrill	Statoil	des.17			283000
West Hercules	Seadrill	Statoil	des.16	495000		
West Linus	Seadrill	ConocoPhilips	mai.19			361000
West Navigator	Seadrill	Shell	jul.14		609000	
West Venture	Seadrill	Statoil	jun.15	435000		
XL Enhanced I	Maersk Drilling	Total	sep.18			377000
XL Enhanced II	Maersk Drilling	Det norske	jan.20			377000
XL Enhanced III	Maersk Drilling	Statoil	jul.19			397000

Appendix B

The content of Appendix B is copied in its entirety from NORSOK D-010 rev. 4, and fit to the format of this thesis.

13.3 Well barrier acceptance criteria

13.3.1 General well barrier acceptance criteria in underbalanced and managed pressure drilling

The following apply:

a) All WBEs shall be rated to withstand the maximum differential pressure expected for planned operation mode (UBD or MPD) including a predefined safety factor.
b) A complete list of possible leak paths shall be made.
c) A risk assessment shall be done to assess common WBEs. As a minimum, well type (new/re-entry), status, certifying frequency, visual/mechanical surveillance and probability and consequence of failure of each elements should be addressed.
d) A system/equipment acceptance plan shall be made prior to installation

13.3.3 Well barrier acceptance criteria for managed pressure drilling

The primary well barrier in MPD operations is maintained by a statically underbalanced fluid column with applied surface pressure. The BHP is controlled by means of a closed loop surface system and equipment providing back-pressure.

a) The RCD shall be installed above the drilling BOP.
b) A dedicated MPD choke manifold shall be used to control the wellbore pressure and reduce the pressure at surface to acceptable levels before entering the separation equipment or the shakers. A manual MPD choke system is not accepted as a part of the primary well barrier.
c) Plugging, erosion or wash-outs of surface equipment shall not impact the ability to maintain well control.
d) The surface system shall be selected and dimensioned to handle the anticipated fluid/solids, including formation fluids if potential exists for influx removal with MPD.

e) Snubbing facilities shall be used in all pipe light scenarios. Alternatively, the well can be brought into hydrostatic overbalance or a qualified isolation WBE can be placed down hole prior to any probable pipe light scenarios.
f) During any tripping operation, the ability shall be in place to measure either positive backpressure if the RCD is installed, or verify level of liquid in the annulus when the RCD is not installed.
g) The BHP shall be kept at a level that prevents continuous influx of formation fluid into the well. The BHP shall be above maximum confirmed pore/reservoir pressure (including safety margin to account for expected variations in BHP). The pressure can be confirmed by pressure measurement or interpreted from well signals.

The secondary well barrier for MPD is the same as for conventional drilling.

h) A stab-in safety valve for the pipe in use shall be available on the rig floor.
i) A drilling BOP shall be installed for MPD operations
j) j) MPD manifold and flow path shall be independent of rig choke manifold, so the rig choke manifold is always available for well control operations.

To ensure that the wellbore pressure does not exceed the formation integrity, the following apply:

k) A minimum kick tolerance shall be specified. Based on the MPD system's capability of recognizing small influxes and minimizing influx volumes, the kick tolerance can be smaller than for conventional operations.
l) The open hole wellbore pressure range "drilling window" shall as a minimum be such that the MPD system is proved capable of operating within the window for both planned operations and selected predefined contingencies, which shall be based on criticality and frequency of occurrence. As a minimum loss of rig power, choke plugging, change of RCD element and switch between MPD and well control mode (and vice versa) shall be included.
m) Stop criteria for lack of kick margin and/or being out of operating range shall be made. A contingency plan shall be in place and include actions to be taken if this occurs.
n) If the minimum formation stress is lower than the maximum estimated pore pressure in the section, it shall be documented that the risk of fracturing the formation is acceptable, and contingency plans for potential scenarios shall be made.

13.4 Well barrier elements acceptance criteria

There are no additional requirements to what is described in section 15.

13.5 Well control action procedures and drills

13.5.1 Well control action procedures

Main operational risks shall be identified and contingency procedures shall be made, reflecting the actual equipment to be used and the well specific data. The following table describes incident scenarios for which well control action procedures should be available. This list is not comprehensive and additional scenarios may be included based on the planned activities.

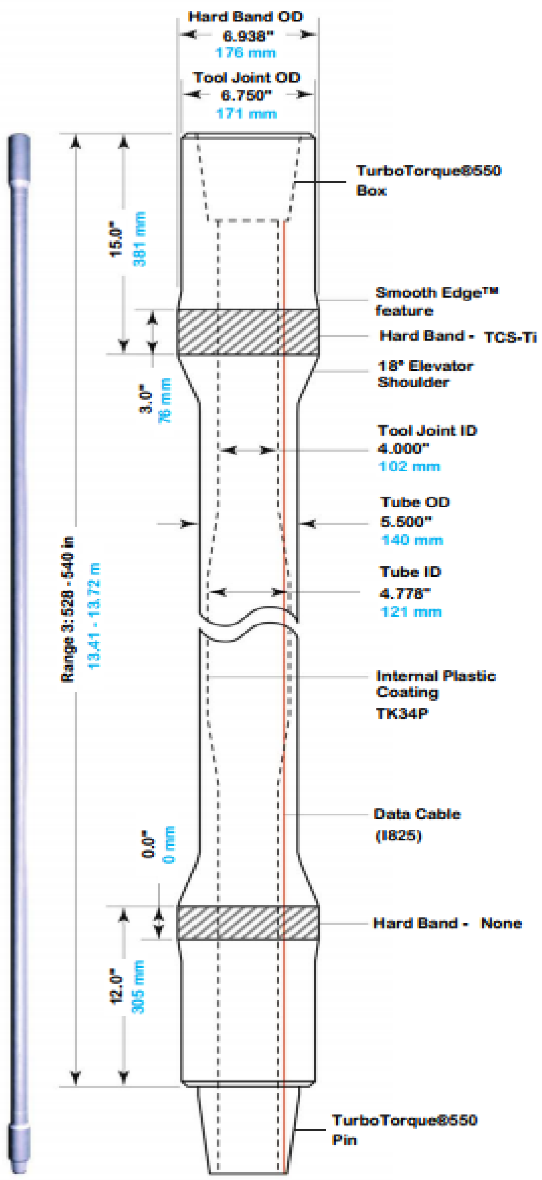
Table 13: Well control action procedures (Standards Norway (NORSOK), 2013)

1.	Bottom hole or surface pressure and/or flow rates detected which could lead to the pressure rating of the RCD (static or dynamic) or the capacity of the surface separation equipment being exceeded	
2.	NRV failure, influx into work string during making connection or tripping in live well	
6		
3.	Leak in common WBE; casing	
4.	Leak in common WBE; casing cement	
5.	Leak in common WBE; WH, HP-riser and BOP	
6.	Gain while: drilling, displacing to overbalance fluid, and with pipe out of hole	MPD only
7.	Erosion or wash out of choke	Consider the case where isolation for repair of the choke cannot be achieved
8.	Leaks at surface	RCD, flowlines, manifold etc.
9.	Plugging at surface	Choke, flowmeter etc.
10.	Work string failure, washout or twist-off	Consider pipe light scenario and contribution from additional NRVs in the drillstring. Evaluate risk for pipe failure based on well path/dog leg severity
11.	Emergency shut-in UBD only	
12.	Emergency well kill and bullheading Including criteria for shut-in	
13.	Lost circulation, on bottom and out of hole	
14.	H_2S in the well	
15.	Loss of rig power	
16.	Simultaneous kick and loss situation	
17.	Stuck pipe	
18.	Failure of method to hold dynamic backpressure during connections	
19.	Rig movement	
20.	Rig/platform alarm with mustering	

Appendix C

IntelliServ™ 5 1/2" Drill Pipe - S-135 TurboTorque®550 Range 3 0.361" Wall

Specification



Specifications and Dimensions

Telemetry Drill Performance Specifications	
Size and Weight	5-1/2" 21.90 IEU
Range	3
Grade	S-135
Connection Type	TurboTorque®550
TUBE	**Imperial**
OD	5.500 in
Wall Thickness	0.361 in
ID	4.778 in
Calculated Plain End Weight	19.814 lbs/ft
Torsional Strength	91,300 ft-lbs
Tensile Strength	786,800 lbs
80% Torsional Strength	73,000 ft-lbs
Cross Sectional Area Pipe Body	5.828 in²
Cross Sectional Area OD	23.758 in²
Cross Sectional Area ID	17.930 in²
Section Modulus	7.031 in³
Polar Section Modulus	14.062 in³
Pressure Capacity[2]	15,507 psi
Collapse Capacity[2]	12,679 psi
TOOL JOINT (130,000 PSI MATERIAL YIELD STRENGTH)	
OD	6.750 in
ID	4.000 in
Pin Tong Length	12.0 in
Box Tong Length	15.0 in
Torsional Strength[3]	86,625 ft-lbs
Max. Acceptable Make-up Torque[3]	60,637 ft-lbs
Min. Acceptable Make-up Torque[3]	43,312 ft-lbs
Balance OD	6.684 in
Tensile Strength	1,257,265 lbs
Tool/Drill Pipe Torsional Ratio	1.15
Min OD for Premium Class	6.315 in
DRILL PIPE ASSEMBLY WITH TurboTorque®550 CONNECTION	
Adjusted Weight	23.58 lbs/ft
Approximate Length	44.08 ft
Fluid Displacement	0.360 gal/ft
Fluid Capacity	0.908 gal/ft
Drift Size[4]	3.875 in

[1] All measurements listed are nominal
[2] Differential pressure
[3] Value includes impact of coil groove
[4] Measurement includes the impact of the Data Cable

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Houston, Texas 77036
United States
Phone: 713 634 3325
IntelliServ@nov.com

ISNWP0024-53KFAP-001 D5C1004432-SPC-001 Rev. 1

Appendix Figure 1: S-135 Quality Wired Drill Pipe specifications (National Oilwell Varco)

Pressurized Mud Cap Drilling

PCMD is best suited when there is a high risk of lost circulation, like many places in the Asia Pacific region where cavernous voids encountered during drilling result in huge fluid losses. An RCD is used to seal off the annulus, but pressures above the operating limit of the RCD can be experienced. To avoid this problem, a light and expendable fluid, like seawater with the appropriate additives, is used to drill the problem zone. This increases ROP, while the drilling fluid along with the cuttings will be forced into the lost circulation zone. By adding a predetermined column height of heavy mud in the annulus in addition to surface backpressure no fluid is returned to surface from the annulus. Well control is thus maintained even if substantial fluid losses occur. It can be discussed whether this technique is a proactive or reactive one, as wells often are drilled conventionally until the problem zone is encountered, thus placing it in the latter category (Birkeland, 2009).

Dual Gradient Drilling

Dual Gradient Drilling (DGD) introduces the idea of drilling using two different pressure gradients in the well; one between the rig and the wellhead, and one between the wellhead and TD. DGD may be accomplished in several ways:

- Injecting lower density fluids, such as nitrogen or sea water, downhole through the riser
- By utilizing mud returns systems to pump returns topside or regulate the mud level in the riser

The objective is to manipulate the BHP without circulating in new drilling fluids. The method is especially useful in Deep Water applications, as the heavy mud column in the riser may be replaced by a lower density fluid, reducing the BHP, and may thus contribute to reducing formation damage and fluid losses when drilling through deep formations with low fracture gradients (Mæland, 2013).

Returns Flow Control MPD

The objective of using the *Returns Flow Control* (commonly referred to as HSE MPD) MPD technique is to drill with a closed loop system, minimizing the risk of getting hazardous materials on deck. Such materials may include unexpected hydrocarbons (kicks) and corrosive mud systems, and presents a risk to the health and safety of the deck crew and to the environment. Maintaining a closed loop mud system is achieved by using an RCD and an NRV. This technique is especially applicable when drilling through HPHT formations. Otherwise, HSE MPD is conducted using conventional drilling programs and components (Hannegan, 2011).

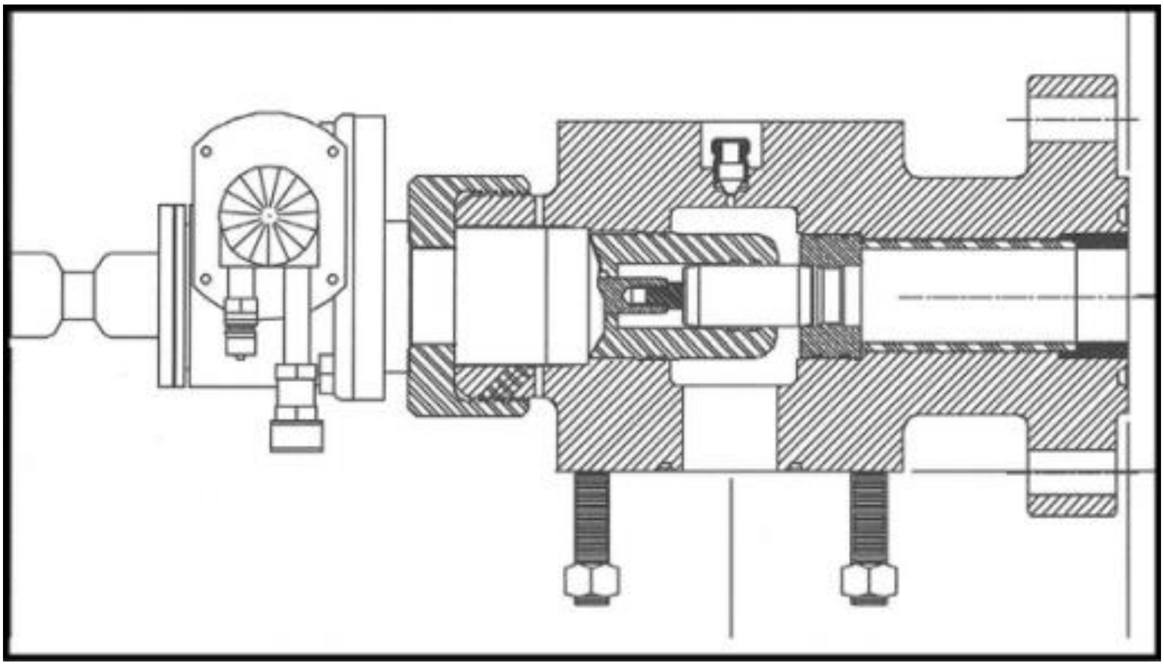
Additional Tools and Systems

The information that follows is copied in its entirety from (Rehm, et al., 2008), and fit to the format of this thesis.

Chokes

Power Choke

The Power Choke SC models use a cylinder-type choke gate that moves forward to choke against a seat (Appendix Figure 2). The trim is pressure balanced to allow smooth operation. When closed, the choke gate sets against the seat to form a leak-tight seal. Choke operation is by an air-operated hydraulic pump. Normal operation is a hydraulic motor that operates a worm gear, although an electric motor is available. The hydraulic motor is rated for 1200‑3000 starts and stops per hour to allow continuous precise choke operation. A manual override is on all worm gear drives.



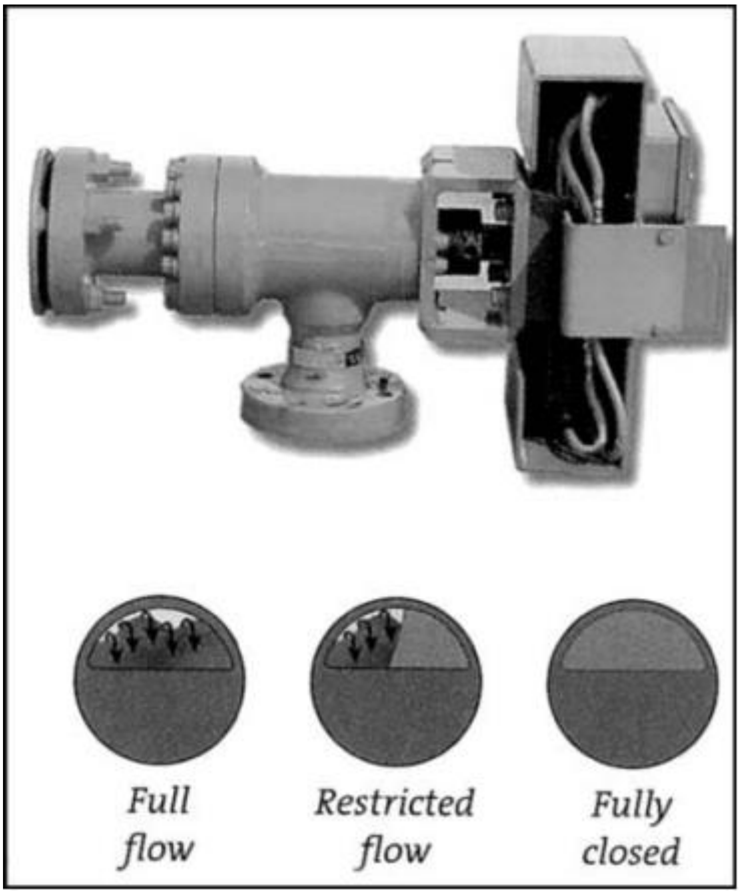
Appendix Figure 2: Power Choke Section

The control panel contains the pump stroke counters, hydraulic pump, annular and drill-pipe pressure gauges, control handle, choke position indicator, and pump-speed controller, which controls the opening and closing speed. Chokes are available in 5000-, 10,000-, 15,000-, and 20,000-psi operating pressure models. Drilling chokes for MPD operations are available in 2-in. and 3-in. sizes. Operation is with a handle for “open” and “close.” The operator controls the choke movement. Unless moved, the choke remains in a fixed position. During MPD operations, the choke maintains a fixed “orifice” unless changed by the operator. Opening and shutting during pump changes are controlled by the choke operator. Failure is extremely rare and generally relates to the inability to seal tightly on a pressure test. The normal operating failure is because of damage to the air or hydraulic system. Because of the worm drive operating system, the choke operating failure mode is always in the last fixed position. The Power Choke has been extensively used in MPD operations. A computer control system that automatically maintains the proper back pressure based on feedback to a proprietary software system is used by Secure Drilling (see Chapter 4 in (Rehm, et al., 2008)) for control during MPD operations.

Swaco Super Choke

The Swaco Super Choke has two 11⁄4-in.-thick lapped tungsten carbide plates with half-moon openings. The front plate is fixed and the rear plate rotates against it to fully open when the openings in the plates are aligned and closed when they are out of phase. Well pressure behind the rotating plate and the lapped seal on the plates allow the choke to close and seal tightly (Appendix Figure 3). The half-moon openings, when in phase, have an area slightly less than 2 in.^{2}. The choke movement is by an air-operated hydraulic pump. Normal operation is a set of hydraulic rams turning the choke plate through a rack and pinion system. Manual pump operation is available if the air supply fails. The choke can also be operated manually by lever.

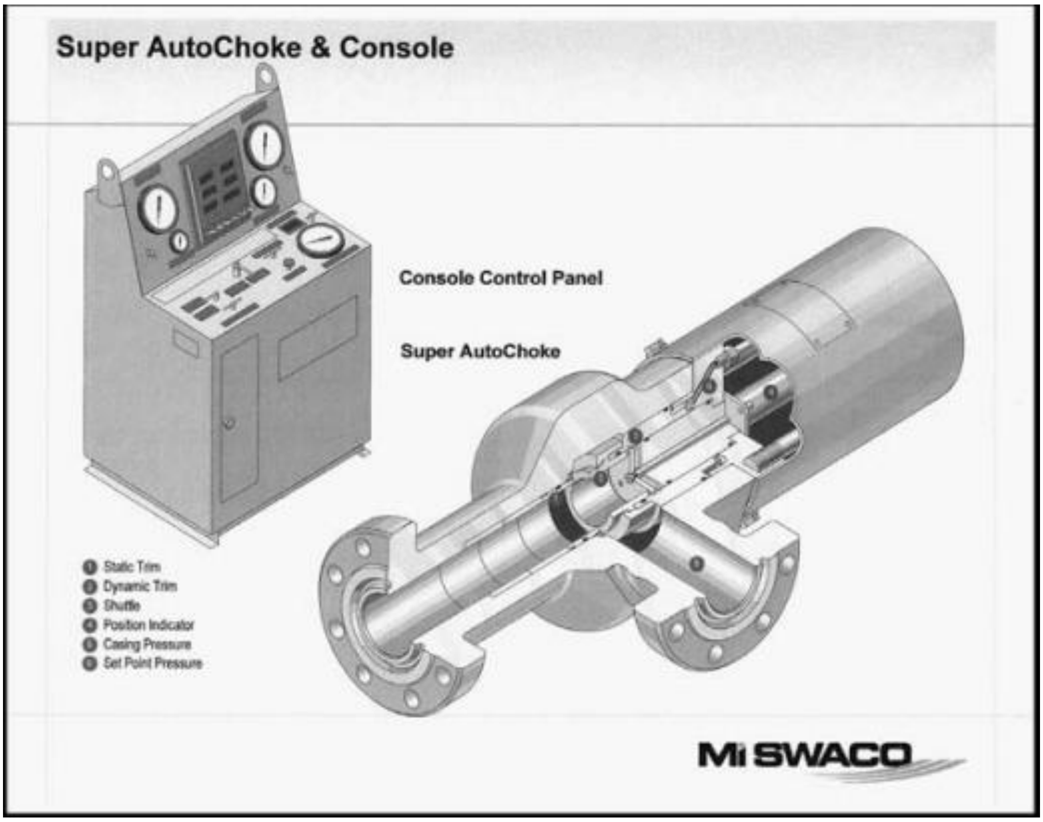
The control panel contains the pump stroke counters, hydraulic pump, annular and drill-pipe pressure gauges, control handle, choke position indicator, and a needle valve that controls the opening and closing speed. Chokes are available in 10,000-, 15,000-, and 20,000-psi operating pressures. All chokes are rated as 2-in. chokes. Operation is with a handle for opening and closing. The operator controls the choke movement. Unless moved, the choke remains in a fixed position. During MPD operations, the choke maintains a fixed “orifice,” unless changed by the operator. Opening and shutting during pump changes is controlled by the choke operator. Failure is extremely rare and generally relates to the inability to seal tightly on a pressure test. The normal operating failure is because of damage to the air or hydraulic system. Because of the rack and pinion operating system, choke operating failure mode is always in the last fixed position.



Appendix Figure 3: M-I SWACO 10K Super Choke and choke plates

Swaco Auto Super Choke

The Auto Choke is suited to MPD operations because it holds the annular pressure constant. The shuttle closes bubble tight on a metal-to-Teflon seal (Appendix Figure 4). The Auto Choke is a completely different choke from the Super Choke. The Auto Choke has a tungsten carbide sliding shuttle in a sleeve directly operated by hydraulic pressure. Pressure set at the console works against the operating area on the shuttle, which is balanced by the well pressure. The casing pressure transmitter is a piston shuttle providing direct pressure to the control panel sensor. The response of the choke to pressure changes is rapid. Choke movement is directly controlled by the hydraulic balance between the well-bore pressure and the hydraulic pressure setting. Normal operation is with an air-operated hydraulic pump. Alternate operation is with a manual hydraulic pump. The control panel contains the set-point indicator, set-point control, pump stroke counters, hydraulic pump, and annular and drill-pipe pressure gauges. This choke is available in 10,000-psi operating pressure and is rated as a 3-in. choke.



Appendix Figure 4: Auto Super Choke

The Auto Choke normally is set in the auto mode, which maintains the casing pressure at a preset value. No further action is required by the operator as long as the preset casing pressure is not to be changed. The Auto Choke can also be operated in a manual mode with the operator controlling the casing pressure (Appendix Figure 4). Failure is rare, with most problems relating to seal tightness on a pressure test. In case of low air pressure, the hydraulic pump can be operated manually. If the hydraulic control lines are cut, the choke goes to the open position.

Drill-Pipe Non-return Valves

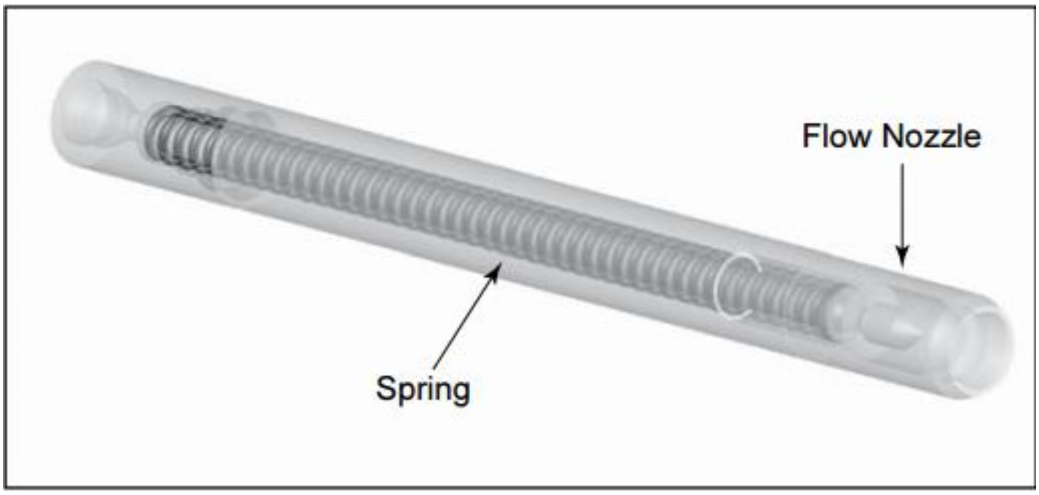
The drill-pipe non-return valve (NRV) is essential to any MPD operation. MPD operations often require annulus back pressure. Looking at the U-tube principle so commonly discussed in well-control activities, it is evident that any positive unbalance in the annulus forces drilling fluid back up the drill pipe. The drilling fluid may carry cuttings that plug the motor or MWD or, in the worst case, blow out the drill pipe. The non-return valve, or one-way valve in the drill pipe, was originally called a float. That term is still in use in older literature and some of the equipment descriptions in catalogs. Within the last several years, the term non-return valve, or NRV, has replaced float as a primary descriptor of the drill-pipe one-way valve.

Basic Piston-Type Float

The primary line of defense against backflow problems has been the type-G Baker float, also called a piston float. The piston NRV has a simple piston driven closed by a spring that looks a bit like an engine valve stem. Drilling fluid pressure forces the valve open against the spring when circulating; and when the pump is turned off, the spring and any well-bore pressure force the valve closed. This type of NRV has proven very reliable and rugged. Failures of this valve have been rare and generally the result of no maintenance or very high-volume pumping of an abrasive fluid. The valve is housed in a special sub above the bit, and it is common and prudent for critical wells to use dual NRVs. The primary two problems with the type-G float are that it blocks the drill pipe for wire line and the use of the float blocks back pressure or shut-in drill-pipe pressure from a well kick. As long as the NRV is located just above the bit, it limits the need to pass a wire line. The shut-in pressure problem is overcome by slowly increasing the pump pressure until it levels out, indicating that the valve is open and the pressure is the equivalent of shut-in pressure.

Hydrostatic Control Valve

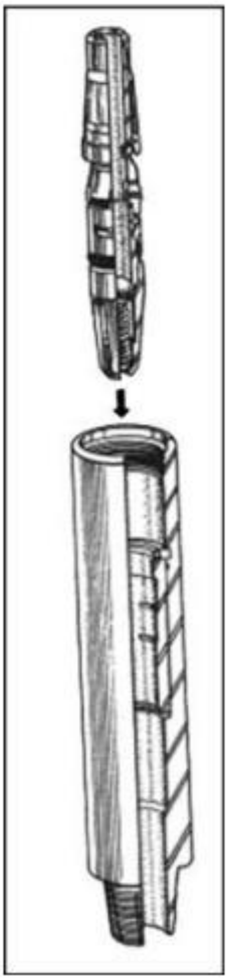
The hydrostatic control valve (HCV) is a subsea version of the bit float valve used in dual-gradient drilling (Appendix Figure 5). It is used to hold up a column of drilling fluid in the drill pipe to avoid the U-tube effect when the pump is turned off. This would be the equivalent pressure of a full column of mud in the riser minus the pressure of an equivalent column of seawater, regardless of the depth of the hole. The HCV does not restrict the use of an NRV at the bit to prevent backflow and plugging. The HCV is a longer tool than the type-G float, to accommodate the spring calibrated to hold the piston closed against the equivalent pressure of a full column of drilling fluid in the riser. See Chapter 8, Section 8.5.2 in (Rehm, et al., 2008), for further discussion and a different design of the tool.



Appendix Figure 5: HCV Valve

Inside BOP (Pump-Down Check Valve)

The inside BOP is an older tool, from the generation of the piston float. The inside BOP is designed as a pump-down tool seated in a sub above the bottom-hole assembly and acting as a check valve against upward flow. The original use of the inside BOP was during a period when there were objections to running an NRV at the bit because of the chance of increasing lost circulation. It is now used as a backup to the bit float. The inside BOP requires a sub in the drill string and inside clearance to run. The sub often, or normally, is run above the collars or bottom-hole assembly. Once run, it is not retrievable and blocks the drill string above the collars (Appendix Figure 6).



Appendix Figure 6: Inside BOP NRV

Retrievable NRV or Check Valve (Weatherford)

The retrievable NRV is an improvement over the older inside BOP, since it can be pulled without making a pipe trip to the surface. There are two versions:

1. The wire-line retrievable dart valve is a reliable system that sets in a sub but does not allow access below it (Appendix Figure 7).
2. The retrievable check valve is a flapper-type NRV. The valve leaves an opening for balls or wire-line passage through the valve.

Down-Hole Annular Valves

Casing Isolation Valve

A significant problem in MPD is maintaining control of bottomhole pressure on a trip. The basis of the MPD system is that it is closely balanced between flow into the well bore and lost circulation. The ECD as a result of pumping versus being static and pulling pipe versus running pipe goes through critical pressure changes. This makes it difficult to control bottom-hole pressure during trips. Trips can be managed by the use of a casing isolation valve (CIV), stripping, snubbing, or killing the well. All of these solutions pose technical or cost and NPT problems.

Advantages

The CIV offers the most positive solution to the MPD problem of trips. With a casing isolation valve, the pipe is stripped up into the casing until the bit is above the valve. The casing isolation valve is then closed, trapping any pressure below it, which allows the trip to

continue in a normal mode without stripping or killing the well. The well bore below the CIV comes to equilibrium with the reservoir pressure. So, in a high-pressure well, to limit pressure buildup below the valve caused by gas migration, the valve needs to be set as deep as practical. This also has the advantage of limiting stripping distance up to the valve level.

Appendix Figure 7: Retrievable NRV

Constraints

The CIV requires a size larger casing to allow space for the valve element to retract and clear the bit. There are also reasonable differential pressure limits, typically in the range of 4000 psi. Extreme bent housings (> 3-4°) with stabilizers, used in directional drilling, may damage the face of the valve.

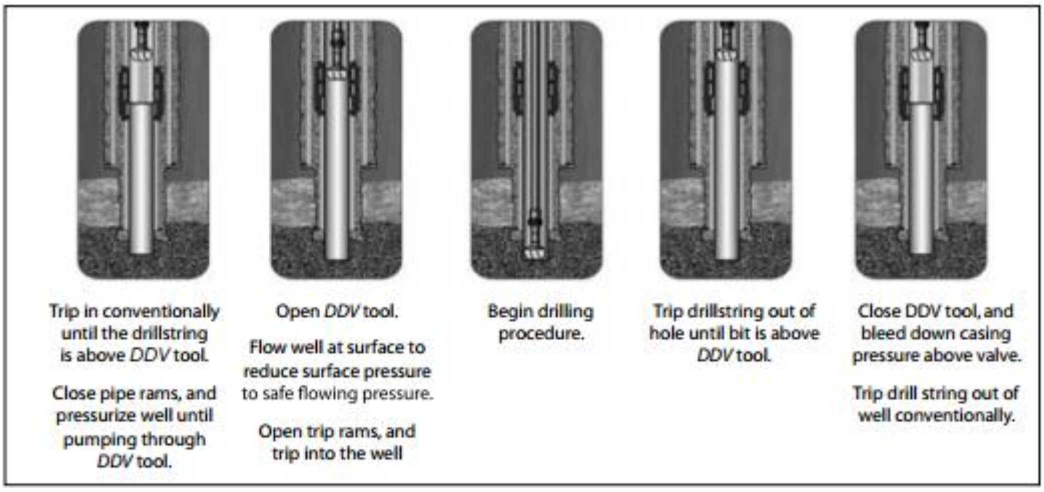
Drilling Down-Hole Deployment Valve

The drilling down-hole deployment valve (DDV™; Weatherford) is a casing isolation valve run as an integral part of casing that is to be set above the formation of interest. The design profile of the tool allows for installation in standard casing programs: The outside diameter (OD) is such that the DDV tool can be installed inside consecutive standard casing strings, and the ID allows for full bore passage. The tool is operated from the surface by an umbilical containing two hydraulic control lines, which are run external to the casing, exiting the casing hanger through a penetrating wellhead, or by using a flanged side port. With the DDV tool installed and the casing landed, the equipment on the surface is a small footprint hydraulic control unit. The valve mechanism itself is a curved, saddle-type flapper, which lands on a matched metal seat to provide the seal. The curved flapper in the open position fits flat against the outer casing string. The tool is run into the well as part of the casing, with the flapper in the locked open position. It is protected during the run-in and drilling by a seal mandrel equipped with a debris barrier (Appendix Figure 8). This allows the casing to be cemented in place conventionally with the flapper fully protected. With the flapper in the open position, the well operator has full bore access for operations such as cement cleanout, drilling, running a liner, perforating, and well completion. When making a trip out of the hole, the pipe is stripped out until the bit is just above the DDV valve. Then, the flapper on the DDV valve is closed by the application of pressure to the "close" control line. Pressure from the control line moves the seal mandrel upward, allowing the flapper to move into the closed position. This isolates the upper part of the hole from pressure below. The upper annular pressure is bled off, and the pipe tripped normally.

Going back in the hole, the pipe or tubing is run in to just above the valve. The rams are closed and the upper well bore is pressured up to equal to the annulus below the DDV valve and fluid pumps through the valve. At this point, hydraulic pressure is applied to the "open" line, driving down the protective seal mandrel and opening the valve. It is important to note that the tool is not pressure equalized, but the DDV tool is a power-open, power closed device. The pressure must be equalized before opening.

Advantages

- The well pressure is isolated below the DDV tool once it is closed. Since there is no pressure at the surface, conventional tripping is feasible.
- The well remains in an underbalanced or balanced condition while tripping.
- Tripping time is significantly less than with any other pressurized or flowing well-bore system.
- No mud density changes are required.
- Minimal footprint and surface equipment are used while drilling.
- It allows for deployment through the BOP stack of long complex assemblies.



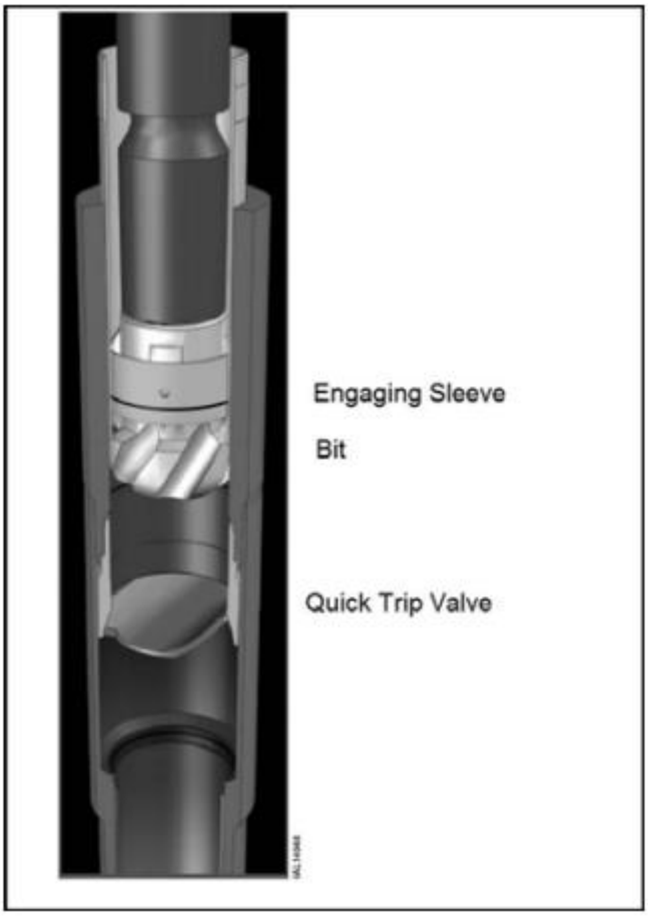
Appendix Figure 8: DDV trip sequence

Limits

- The DDV should not be used on a long-term basis (for production). It contains elastomeric seals that can deteriorate over time when exposed to well effluent.
- The hole size or previous casing needs to be a size larger.
- Pressure limits on the tool must be considered.
- The umbilical cord must be protected during cementing, which may limit pipe reciprocation.

Quick Trip Valve

The quick trip valve (QTV™), Halliburton's version of the casing isolation valve, is run as an integral part of a standard casing string. The valve does not require a larger casing string but, in the open position, restricts the ID of the casing string (Appendix Figure 9). The operation of the QTV is totally mechanical, and it can be run at any depth. To open the valve, the upper annulus is pressured up to the same pressure as below the QTV. A slight overpressure cracks open the valve and acts on the surface like the beginning of a leak-off test. The drill bit acts as the running tool. Pushing through the flapper, it opens the valve. Carried on the gauge shoulder of the drill bit is the engaging sleeve. As the bit passes though the valve, a detent pulls the engaging sleeve off the bit and the ring locks the flapper open. The engaging ring also acts as a debris shield and seals the flapper against the wall of the casing sub. To close the valve, the bit is pulled through the engaging sleeve, which catches on the shoulder on the bit gauge and is pulled free. As the bit clears the valve flapper, it closes and seals the lower well bore.



Appendix Figure 9: Quick trip valve.

Advantages

- The valve is totally mechanical and can be run at any depth.
- The well pressure below a closed QTV tool is isolated from the surface.
- The well remains in an underbalanced or balanced condition while tripping.
- Tripping time is significantly less than with any other pressurized or flowing well-bore system.
- No mud density changes are required.
- No surface equipment is required.
- Long assemblies can be run into the hole through the BOP stack with no danger from well pressures.
- It can be left in the hole at the end of drilling and completion.

Limits

- There is an internal restriction in the casing.
- Pressure limits on the tool must be considered.

ECD Reduction Tool

The ECD reduction tool (ECD RT™; Weatherford) is a turbine pump down-hole tool that produces a dual gradient in the annulus when the mud pump is operating. As such, it is properly both an ECD reduction tool and a dual-gradient system tool. The concepts of dual gradients and how they reduce annular and bottom-hole pressure are discussed in Chapter 8 in (Rehm, et al., 2008). Dual-gradient drilling in the case of this tool is accomplished by "boosting" an upper section of the annulus mud column.

Unique Considerations

The ECD tool works in the opposite direction from the "impressed annulus-pressure" systems. The ECD tool reduces the pressure in the annulus instead of impressing a pressure. The result of this is that a slightly heavier mud density could be used with this tool than with the impressed-pressure techniques. This results in being able to navigate through narrow drilling windows by widening the downhole pressure margins. Dual-gradient operations have an ongoing problem with the U-tube effect. When the mud pump is turned off, the system wants to U-tube to equilibrium. While utilizing the dual-gradient concept, the ECD RT tool does not cause a U-tube effect, because the static mud density is similar in both the drill pipe and annulus. Several early references indicated a 450-psi (3100 kPa) reduction in annular pressure at 600-gpm (2300 Lpm) flow rate. The ECD RT was designed and developed jointly by BP and Weatherford to provide a low-cost, easy to install and use, tool for ECD reduction.

Advantages

- It requires no drill rig modification or surface footprint. It can be added to the drill string on a short trip.
- No on-site operator is required.
- It can reduce spikes in equivalent mud-weight values associated with making connections. The result is a more constant well-bore pressure profile, whether drilling ahead (pumps on/circulating) or making a connection (pump off/not circulating).
- In extended-reach wells, it could reduce the ECD problem between the toe and the heel of the well by boosting the drilling fluid in the long reach section.
- It does not affect mud-pulse MWD signals.
- The tool is open to wire-line operations.

Challenges

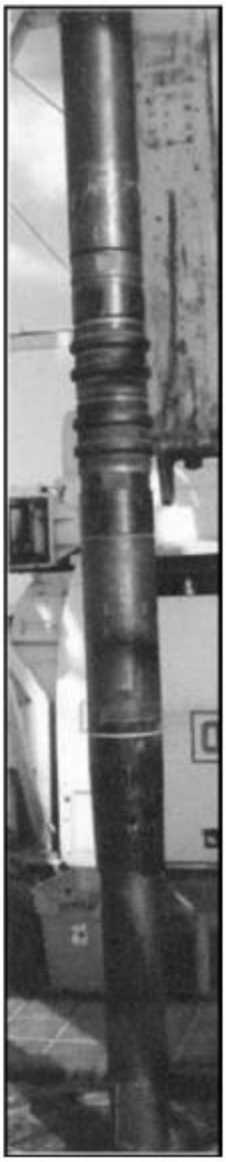
- The most significant challenge is when running or pulling the tool. The turbine pump section in the annulus limits the annular area over a short section (Appendix Figure 10). Pipe movement creates an increased pressure-surge proportional to the rate of pipe movement.
- The annulus restriction passes normal cuttings, but heavy gumbo could cause a problem.
- The internal drill-pipe turbine motor uses energy and so increases pump pressure.

Description

The ECD RT tool consists of three sections (

Appendix Figure 11):

1. At the top is a turbine motor, which draws pressure energy from circulating fluid and converts it into mechanical power. Circulating fluid enters the turbine motor at the top and comes back into the drill string after driving the turbine motor.
2. In the middle is a multistage, mixed-flow pump driven by the turbine motor. It pumps return fluid up in the annulus.
3. The lower section consists of bearings and seals. The turbine motor is matched to pump duty so there is no need for a gearbox. Two seals on the outside of the pump seal it against the casing ID, which forces all the return fluid to pass through the pump.



Appendix Figure 10: ECD tool (courtesy of Weatherford International Ltd.)

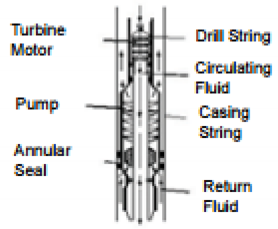
Coriolis Flowmeter

The flowmeter is an important part of flow measurement in some MPD operations. Since the Coriolis meter is new to drilling operations, the following description is included as part of the general background for surface equipment. The flowmeter discussed in Chapter 4 in (Rehm, et al., 2008) is the Emerson Micromotion Coriolis Meter. The Coriolis meter depends on a flowing mass deflecting a tube. Typically this is shown as a U-tube (Appendix Figure 12), and this is the configuration shown in Chapter 4 in (Rehm, et al., 2008). The Coriolis meter is a very accurate method of measuring drilling fluids since they contain drill cuttings that tend to interfere with other types of flowmeters. The meter measures and calculates:

- Mass flow.
- Volumetric flow.
- Density.
- Temperature.

Specifications

	Specifications
Maximum Pressure Boost, psi	450
Optimum Circulation Rate, gpm	500-600
Outside Diameter, in.	
Turbine Motor	6.75
Pump	8.20
Inside Diameter (After Retrieving a Flow Diverter), in.	2.81
Overall Length, in.	360 (30-ft)
Mecanical Strength	Similar to 5"-19.5 lb/ft. New S-135 New Drillpipe
Application in Casing Sizes	
Connections	4½" IF



Appendix Figure 11: ECD tool data (Courtesy of Weatherford International Ltd.

Following is a simple general description of how the system works. For a more precise description and the mathematical concepts, see the references under Coriolis Meter.

1. Dual parallel flow tubes, U-tubes, are oscillated in opposition to each other at their natural frequency by a magnet and coil.
2. Magnet and coil assemblies are mounted on the inlet and outlet side of the parallel flow tubes with the magnets on one tube and the coils on the other.
3. The vibration of the tubes (Appendix Figure 12) causes the coil output to be a sine wave that represents the motion of one tube relative to the other.
4. When there is no flow, the sine waves from the input and output coils coincide.
5. The Coriolis Effect from a mass flow through the inlet side of the tubes resists the vibration. The Coriolis Effect from the mass flow through the outlet side of the tubes adds to the vibration.
6. The phase difference between the signal from the input and output sides is used to calculate mass flow.
7. Frequency change from the natural frequency indicates density change. Increasing mass decreases frequency.
8. Volume flow is mass flow divided by density.
9. Direct temperature measurement is used to correct for temperature changes.

Appendix Figure 12: The basis of the Coriolis meter is twin parallel tubes. (Courtesy of Yokogawa.)

Appendix D

Table 14: Commonly used bit size that will pass through API casing (Petrowiki)

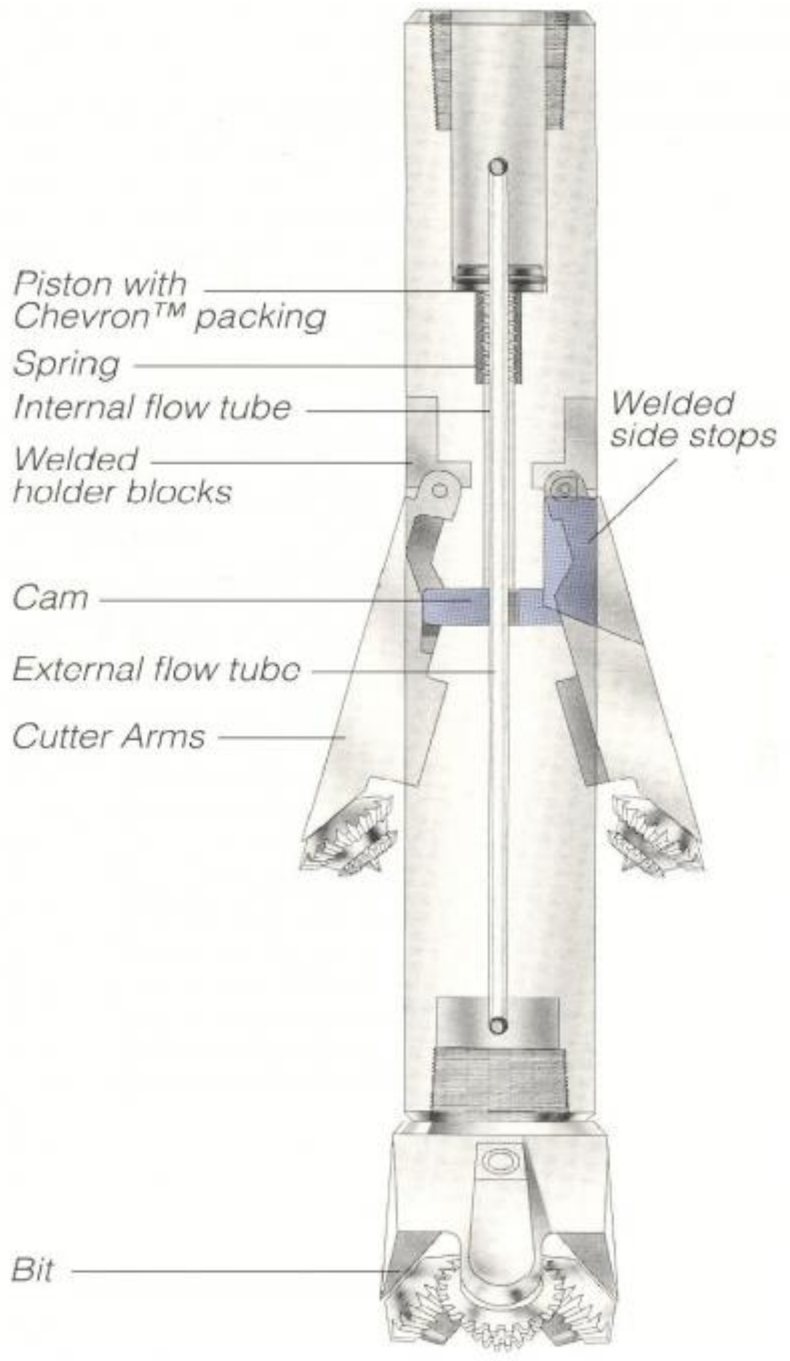
Casing Size, OD, in.	Weight/ft, lbm/ft	ID, in.	Drift Diameter, in.	Commonly Used Bit Sizes, in.
4 1/2	9.5	4.090	3.965	3 7/8
	10.5	4.052	3.927	
	11.6	4.000	3.875	
	13.5	3.920	3.795	3 3/4
5	11.5	4.560	4.435	4 1/4
	13.0	4.494	4.369	
	15.0	4.408	4.283	
	18.0	4.276	4.151	3 7/8
5 1/2	13.0	5.044	4.919	4 3/4
	14.0	5.012	4.887	
	15.5	4.950	4.825	
	17.0	4.892	4.764	
	20.0	4.778	4.653	4 5/8
	23.0	4.670	4.545	4 1/4
6 5/8	17.0	6.135	6.010	6
	20.0	6.049	5.924	5 5/8
	24.0	5.921	5.796	
	28.0	5.791	5.666	
	32.0	5.675	5.550	4 3/4
7	17.00	6.538	6.413	6 1/4
	20.00	6.456	6.331	
	23.00	6.366	6.241	
	26.00	6.276	6.151	6 1/8
	29.00	6.184	6.059	6
	32.00	6.094	5.969	
	35.00	6.006	5.879	
	38.00	5.920	5.795	5 5/8
7 5/8	20.00	7.125	7.000	6 3/4
	24.00	7.025	6.900	
	26.40	6.969	6.844	
	29.70	6.875	6.750	
	33.70	6.765	6.640	6 1/2
	39.00	6.625	6.500	
8 5/8	24.00	8.097	7.972	7 7/8
	28.00	8.017	7.892	
	32.00	7.921	7.796	6 3/4
	36.00	7.825	7.700	
	40.00	7.725	7.600	
	44.00	7.625	7.500	
	49.00	7.511	7.386	

Table 15: Commonly used bit sizes that will pass through API casing (continued) (Petrowiki)

$9\frac{5}{8}$	29.30	9.063	8.907	$8\frac{3}{4}$, $8\frac{1}{2}$
	32.30	9.001	8.845	
	36.00	8.921	8.765	
	40.00	8.835	8.679	$8\frac{5}{8}$, $8\frac{1}{2}$
	43.50	8.755	8.599	
	47.00	8.681	8.525	$8\frac{1}{2}$
	53.50	8.535	8.379	$7\frac{7}{8}$
$10\frac{3}{4}$	32.75	10.192	10.036	$9\frac{7}{8}$
	40.50	10.050	9.894	
	45.50	9.950	9.794	$9\frac{5}{8}$
	51.00	9.850	9.694	
	55.00	9.760	9.604	
	60.70	9.660	9.504	$8\frac{3}{4}$, $8\frac{1}{2}$
	65.37	9.560	9.404	$8\frac{3}{4}$, $8\frac{1}{2}$
$11\frac{3}{4}$	38.00	11.154	10.994	11
	42.00	11.084	10.928	$10\frac{5}{8}$
	47.00	11.000	10.844	
	54.00	10.880	10.724	
	60.00	10.772	10.616	
$13\frac{3}{8}$	48.00	12.715	12.559	$12\frac{1}{4}$
	54.50	12.615	12.459	
	61.00	12.515	12.359	
	68.00	12.415	12.259	
	72.00	12.347	12.191	11
16	55.00	15.375	15.188	15
	65.00	15.250	15.062	
	75.00	15.125	14.939	$14\frac{3}{4}$
	84.00	15.010	14.822	
	109.00	14.688	14.500	
$18\frac{5}{8}$	87.50	17.755	17.567	$17\frac{1}{2}$
20	94.00	19.124	18.936	$17\frac{1}{2}$

Underreamers

An underreamer is a drill string mounted tool used to enlarge a wellbore past its original drilled size. The tool is typically actuated hydraulically or mechanically, extending arms carrying drill cutters intended to enlarge the hole. An example of such a tool can be seen in Appendix Figure 13.



Appendix Figure 13: An example of an underreamer (Bakersfield Bit & Tools)

Table 16: Illustration of underreamer opening size on today's market (Jahns, 2012)

Company	Underreamer Name	Body Diameter [in]	Standard Opening Diameter [in]	Enlargement [%]
Baker Hughes	GaugePro XPR Expandable Reamer	8 1/2	9 7/8	16
		10 5/8	12 1/4	15
		12 1/4	14 3/4	20
		14 1/2	17 1/2	20
		16 1/2	20	21
		18 1/8	22	21
Halliburton	XR™ Reamer borehole Enlargement Tool	8 1/4	9 - 12 1/4	9 to 48
		10 1/4	11 - 15 3/4	7 to 53
		12	13 1/2, 14, 14 3/4, 16, 17 1/2, 18 1/4	12, 16, 23, 33, 46, 52
		14 1/4	14 1/2 - 20 1/2	2 to 44
		15 3/4	17 1/2 - 22	11 to 40
Schlumberger	Rhino XS Hydraulically Expandable Reamer	7 1/4	8, 9	10 to 23
		8	9, 10 1/4	12,5 to 27
		9 1/4	10 1/4, 11 3/4	25 to 56
		10	11, 12 1/2	25 to 57
		10 3/8	11 3/4, 13 1/2	25 to 58
		10 5/8	13, 15	25 to 59
		13	14 1/2, 16	25 to 60
		14 1/4	15 3/4, 18 1/4	25 to 61
		16	17 1/2 - 20	9 to 25
		17 1/2	21 1/2 - 22	23 to 26
Weatherford	Riptide ®	8 1/4	9, 9 7/8	20
		10 1/4	11 3/4, 12 1/4, 13	20
		11 3/4	14 3/4	25
		14 1/4	17 1/2	23
		15 3/4	20 - 22	27 to 40

Appendix E

Flow Diverter Valve

Drill String mounted Flow Diverter Valves may be used in order to reduce the significance of flow rate related issues caused by the narrow hydraulic diameter in the annulus; certain components in the BHA, such as RSS assemblies and mud motors The purpose of such a valve is to divert a part of the flow above the liner to the surrounding annulus, thus reducing the flow rate around the liner exposed to the formation.

Such valves are usually actuated by ball-drop or RFID-tagging, and serves to divert a portion of the flow to the surrounding annular space, while the rest is routed downhole. If such a valve is mounted above the liner string, the flow rate is reduced between the liner string and open hole. As is demonstrated in Chapter 6, there is a close correlation between borehole diameter and annular friction loss, and it may thus be safely assumed that a reduction in flow rate will cause a reduction in AFP.

Appendix F

Case Study Calculations

Table 17: Supplementary input and output parameters for

Figure 7-6 (OBD)

	Input Parameters		
Mud weight	ρ_{mud}	1835	kg/m^3
Plastic Viscosity	μ_{pl}	0.024	Pas
Yield Stress	τ_y	6	Pa
Rate of Penetration	ROP	30	m/hr
Pumping Rate	Q	2400	lpm
Sea Water Depth	MSL	360	m
Length of Liner String	L_{ls}	0	m
Length of Drilled Interval	$L_{drilled}$	3217.142857	m
Length of Well	MD	7357.142857	m
True Vertical Depth (RKB)	TVD	5445.063545	m
Bit Size	d_{bit}	8.5	inches
Cuttings Density	$\rho_{cuttings}$	2700	kg/m^3
Cuttings Volume Rate	$q_{cuttings}$	1.098288461	m^3/h
Depletion		160	bar
Biot Coefficient		0.95	
Poisson's Ratio		0.3	
Back Pressure			bar
Safety Margins		5	%
Newtonian	Δp_{ann}	89	bar
Bingham Plastic	Δp_{ann}	77	bar
Power-Law	Δp_{ann}	104	bar
Force Turbulent Flow?	No		
Cuttings transport (v>0.8m/s)	Wellbore Cleaning OK!		
Top of Reservoir Layer	$d_{r,top}$	4162	m
Bottom of Reservoir Layer	$d_{r,bot}$	4594.25	m
Flow Regime	Bingham Plastic		
Static Bottom-Hole Pressure	$p_{BHP,\ static}$	1049	bar

	$p_{BHP, dynamic}$	1126	bar
	$p_{BHP, dynamic}$	2.108282054	SG

Table 18: Supplementary input and output parameters for Figure 7-7 (LD)

	Input Parameters		
Mud weight	ρ_{mud}	1835	kg/m^3
Plastic Viscosity	μ_{pl}	0.024	Pas
Yield Stress	τ_y	6	Pa
Rate of Penetration	ROP	30	m/hr
Pumping Rate	Q	2400	lpm
Sea Water Depth	MSL	360	m
Length of Liner String	L_{ls}	3167.142857	m
Length of Drilled Interval	$L_{drilled}$	3222.142857	m
Length of Well	MD	7362.142857	m
True Vertical Depth (RKB)	TVD	5446.60863	m
Bit Size	d_{bit}	8.5	inches
Cuttings Density	$\rho_{cuttings}$	2700	kg/m^3
Cuttings Volume Rate	$q_{cuttings}$	1.098288461	m^3/h
Depletion		160	bar
Biot Coefficient		0.95	
Poisson's Ratio		0.3	
Back Pressure			bar
Safety Margins		5	%
Newtonian	Δp_{ann}	303	bar
Bingham Plastic	Δp_{ann}	244	bar
Power-Law	Δp_{ann}	342	bar
Force Turbulent Flow?	No		
Cuttings transport (v>0.8m/s)	Wellbore Cleaning OK!		
Top of Reservoir Layer	$d_{r,top}$	4162	m
Bottom of Reservoir Layer	$d_{r,bot}$	4594.25	m
Flow Regime	Bingham Plastic		
Static Bottom-Hole Pressure	$p_{BHP, static}$	1049	bar
	$p_{BHP, dynamic}$	1293	bar
	$p_{BHP, dynamic}$	2.420270021	SG

Table 19: Supplementary input and output parameters for Figure 7-8 (MPD)

	Input Parameters		
Mud weight	ρ_{mud}	1650	kg/m^3
Plastic Viscosity	μ_{pl}	0.024	Pas
Yield Stress	τ_y	6	Pa
Rate of Penetration	ROP	30	m/hr
Pumping Rate	Q	2400	lpm
Sea Water Depth	MSL	360	m
Length of Liner String	L_{ls}	0	m
Length of Drilled Interval	$L_{drilled}$	3217.142857	m
Length of Well	MD	7357.142857	m
True Vertical Depth (RKB)	TVD	5445.063545	m
Bit Size	d_{bit}	8.5	inches
Cuttings Density	$\rho_{cuttings}$	2700	kg/m^3
Cuttings Volume Rate	$q_{cuttings}$	1.098288461	m^3/h
Depletion		160	bar
Biot Coefficient		0.95	
Poisson's Ratio		0.3	
Back Pressure		45	bar
Safety Margins		1	%
Newtonian	Δp_{ann}	72	bar
Bingham Plastic	Δp_{ann}	78	bar
Power-Law	Δp_{ann}	91	bar
Force Turbulent Flow?	No		
Cuttings transport (v>0.8m/s)	Wellbore Cleaning OK!		
Top of Reservoir Layer	$d_{r,top}$	4162	m
Bottom of Reservoir Layer	$d_{r,bot}$	4594.25	m
Flow Regime	Bingham Plastic		
Static Bottom-Hole Pressure	$p_{BHP,\ static}$	944	bar
	$p_{BHP,\ dynamic}$	1022	bar
	$p_{BHP,\ dynamic}$	1.912659153	SG

Table 20: Supplementary input and output parameters for Figure 7-9 (MPCD)

	Input Parameters		
Mud weight	ρ_{mud}	1640	kg/m^3
Plastic Viscosity	μ_{pl}	0.024	Pas
Yield Stress	τ_y	6	Pa
Rate of Penetration	ROP	30	m/hr
Pumping Rate	Q	2400	lpm
Sea Water Depth	MSL	360	m
Length of Liner String	L_{ls}	3167.142857	m
Length of Drilled Interval	$L_{drilled}$	3222.142857	m
Length of Well	MD	7362.142857	m
True Vertical Depth (RKB)	TVD	5446.60863	m
Bit Size	d_{bit}	8.5	inches
Cuttings Density	$\rho_{cuttings}$	2700	kg/m^3
Cuttings Volume Rate	$q_{cuttings}$	1.098288461	m^3/h
Depletion		160	bar
Biot Coefficient		0.95	
Poisson's Ratio		0.3	
Back Pressure		45	bar
Safety Margins		1	%
Newtonian	Δp_{ann}	268	bar
Bingham Plastic	Δp_{ann}	230	bar
Power-Law	Δp_{ann}	311	bar
Force Turbulent Flow?	No		
Cuttings transport (v>0.8m/s)	Wellbore Cleaning OK!		
Top of Reservoir Layer	$d_{r,top}$	4162	m
Bottom of Reservoir Layer	$d_{r,bot}$	4595	m
Flow Regime	Bingham Plastic		
Static Bottom-Hole Pressure	$p_{BHP,\ static}$	939	bar
	$p_{BHP,\ dynamic}$	1169.25900211085	bar
	$p_{BHP,\ dynamic}$	2.18834376	SG

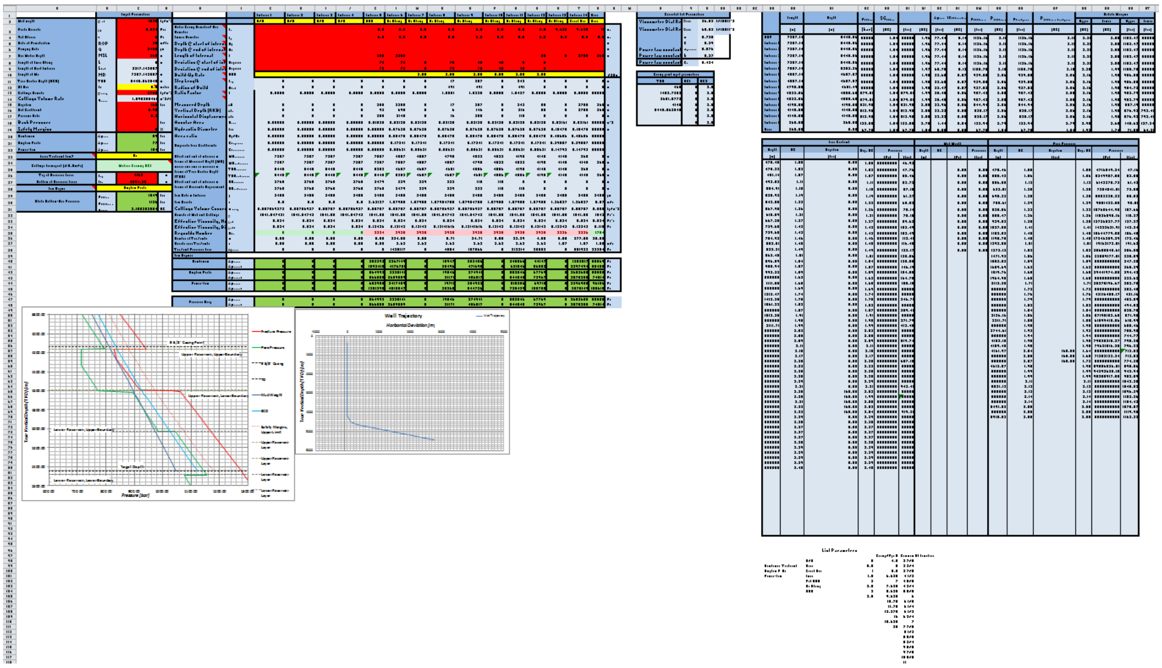
Appendix G

Notes on using the hydraulic model

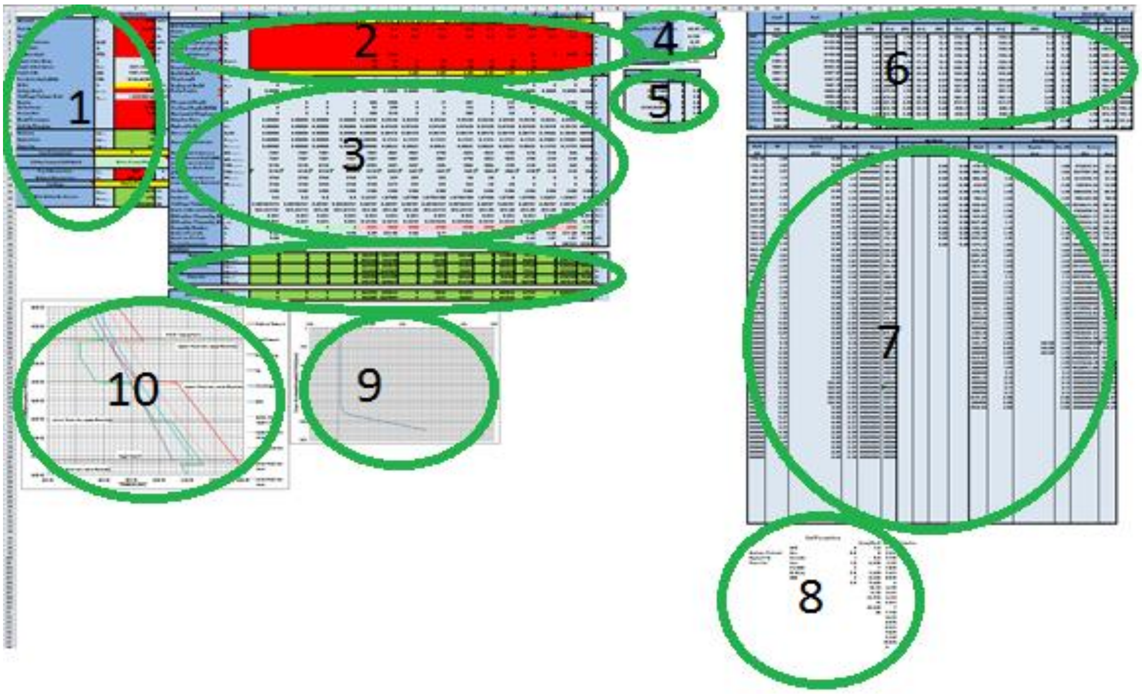
The model has been set up so that it should be relatively easy to use for anyone with a background in drilling engineering. Different people may, however, have different ideas about how things should look and be organized. In addition, the model is fairly complicated, with a lot of calculation steps. Therefore, it is prudent to provide a simple explanation of how the model should be used.

The Excel sheet is color coded for easy comprehension:

- Red cells indicates input parameters
- Yellow cells are drop-down boxes, which means that there are restrictions on the values one can use
- Green cells are important output parameters. These mostly pertain to pressure losses along the well for a given interval
- Light blue cells are generally used for calculations (except from where pressure gradients and depths are implemented in the sheet), and should not be interfered with.



Appendix Figure 14: Overview of the hydraulic model



Appendix Figure 15: Numbered overview of the hydraulic model

In order to provide an overview of the model, each section has been numbered.

1. Shown in Appendix Figure 16. Drilling parameters such as mud weight, ROP, depths, pump rate, etc. are inserted here. The user must also insert reservoir related parameters, such as reservoir layer depth, biot coefficient and depletion. Output parameters provided for the user include pressure drops along the wellbore for different rheological models and BHP. The user have the option of forcing turbulent flow if he or she wishes and may chose the rheological model to be used (Bingham Plastic is the default). A control function has been set up to give feedback to the user if the fluid velocity drops below v = 0.8 m/s in any section of the well.
2. Shown in Appendix Figure 17. Input parameters pertaining to the wellbore trajectory and diameter goes here. The model uses the information from the yellow boxes at the top to calculate casing setting points, and inclination change along with build-up rate (DLS) to calculate the length of build-up sections.
3. Shown in Appendix Figure 18. This part of the model is used to calculate everything that may be extrapolated from the information provided thus far, such as wellbore trajectory, flow velocities, flow regimes, etc. This part of the model should not be interfered with.
4. Shown in Appendix Figure 19. These cells calculate additional fluid parameters that are used in pressure loss calculations. These should not be interfered with.

5. Shown in Appendix Figure 20. These cells are used to calculate casing point depths, and should not be interfered with.
6. Shown in Appendix Figure 21. This part is used to calculate the pressure drop for each interval in order to generate the graphics. This should not be interfered with.
7. Shown in Appendix Figure 22. The user is required to provide input used to generate fracture and pore pressure curves in this part of the model. It is sufficient to insert depths and associated pressures in the appropriate cells – the model will calculate everything else. Care must be taken when defining depletion and reservoir depths, as the model is not set up to identify these parameters automatically.
8. Shown in Appendix Figure 23. These cells are used to define the lists for the drop-down boxes used elsewhere in the model. These cells can be ignored.
9. Shown in Appendix Figure 24 – Shows a 2-D graphical representation of the well trajectory.
10. Shown in Appendix Figure 25 – Shows a graphical representation of the pressure regimes in the wellbore.

	Input Parameters		
Mud weight	ρmud	1835	kg/m^3
Plastic Viscosity	μpl	0.024	Pas
Yield Stress	τy	6	Pa
Rate of Penetration	ROP	30	m/hr
Pumping Rate	Q	2400	lpm
Sea Water Depth	MSL	360	m
Length of Liner String	Lls	0	m
Length of Drilled Interval	Ldrilled	3217.142857	
Length of Well	MD	7357.142857	m
True Vertical Depth (RKB)	TVD	5445.063545	m
Bit Size	dbit	8.5	inches
Cuttings Density	ρcuttings	2700	kg/m^3
Cuttings Volume Rate	$q_{cuttings}$	1.098288461	m^3/h
Depletion		160	bar
Biot Coefficient		0.95	
Poisson's Ratio		0.3	
Back Pressure			bar
Safety Margins		5	%
Newtonian	Δpann	89	bar
Bingham Plastic	Δpann	77	bar
Power-Law	Δpann	104	bar
Force Turbulent Flow?	No		
Cuttings transport (v>0.8m/s)	Wellbore Cleaning OK!		
Top of Reservoir Layer	$d_{r,top}$	4162	m
Bottom of Reservoir Layer	$d_{r,bot}$	4594.25	m
Flow Regime	Bingham Plastic		
Static Bottom-Hole Pressure	$p_{BHP,\ static}$	1049	bar
	$p_{BHP,\ dynamic}$	1126	bar
	$p_{BHP,\ dynamic}$	2.108282054	SG

Appendix Figure 16: Input and output parameters

		Interval 1	Interval 2	Interval 3	Interval 4	Interval 5	Interval 6	Interval 7	Interval 8
		N/A	N/A	N/A	N/A	BHA	Drill String	Drill String	Drill String
Outer Casing Diameter/ Hole Diameter	$d_{w,i}$					8.5	8.5	8.5	8.5
Inner Diameter	$d_{p,i}$					6.5	5.5	5.5	5.5
Depth @ start of interval	V_1								
Depth @ end of interval	V_2								
Length of Interval	L_i					300	2250		
Deviation @ start of interval	Degrees					72	72	0	70
Deviation @ end of interval	Degrees					72	72	0	72
Build-Up Rate	BUR							3.50	3.50

Appendix Figure 17: Wellbore parameters

Step Length	L_{step}	0	0	0	0	0	0	0	17
Radius of Build	R_{build}	0	0	0	0	0	0	0	491
Ratio Factor	F	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.0001
Measured Depth	ΔD	0	0	0	0	300	2250	0	17
Vertical Depth (RKB)	Δd_v	0	0	0	0	93	695	0	6
Horizontal Displacement	Δd_h	0	0	0	0	285	2140	0	16
Annular Area	$A_{ann,i}$	0.00000	0.00000	0.00000	0.00000	0.01520	0.02128	0.02128	0.02128
Hydraulic Diameter	d_{hydr}	0.00000	0.00000	0.00000	0.00000	0.05080	0.07620	0.07620	0.07620
Area ratio	A_1/A_2	0.00000	0.00000	0.00000	0.00000	0.00000	0.58478	0.58478	0.58478
Singularity Loss Coefficients	$K_{L,expansion}$	0.00000	0.00000	0.00000	0.00000	0.00000	0.17241	0.17241	0.17241
	$K_{L,contraction}$	0.00000	0.00000	0.00000	0.00000	0.00000	0.08621	0.08621	0.08621
Start and end of intervals in terms of Measured Depth (MD)	$MD_{start\ of\ interval}$	7357	7357	7357	7357	7057	4807	4807	4790
	$MD_{end\ of\ interval}$	7357	7357	7357	7357	7357	7057	4807	4807
Start and end of intervals in terms of True Vertical Depth (TVD)	$TVD_{start\ of\ interval}$	5445	5445	5445	5445	5352	4657	4657	4651
	$TVD_{end\ of\ interval}$	5445	5445	5445	5445	5445	5352	4657	4657
Start and end of intervals in terms of Horizontal Displacement	$HD_{start\ of\ interval}$	2765	2765	2765	2765	2479	339	339	323
	$HD_{end\ of\ interval}$	2765	2765	2765	2765	2765	2479	339	339
Flow Rate in Interval	q_i	2400	2400	2400	2400	2400	2400	2400	2400
Flow Velocity	v	0.8	0.8	0.8	0.8	2.63136699	1.87954785	1.87954785	1.879547849
Cuttings Volume Concentration	$c_{cuttings,0}$	0.007569272	0.007569272	0.00756927	0.007569272	0.00756927	0.00756927	0.00756927	0.007569272
Density of Mud and Cuttings	ρ_{mix}	1841.547421	1841.547421	1841.54742	1841.547421	1841.54742	1841.54742	1841.54742	1841.547421
Effective Viscosity, Newtonian	$\mu_{eff,N}$	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024
Effective Viscosity, Bingham	$\mu_{eff,BH}$	0.024	0.024	0.024	0.024	0.12425508	0.13141616	0.13141616	0.13141616
Reynolds Number	N_{Re}	0	0	0	0	3334	2920	2920	2920
Number of Tool Joints	n	0.00	0.00	0.00	0.00	0.00	224.00	0.00	0.71
Velocity over Tool Joints	v	0.00	0.00	0.00	0.00	0.00	2.63	2.63	2.63
Tool Joint Pressure Loss	$\Delta p_{tool\ joint}$	0	0	0	0	0	1428117	0	4554

Appendix Figure 18: Calculations

Calculated Fluid Parameters			
Viscometer Dial Readings	θ_{300}	36.5313	lb/100ft^2
Viscometer Dial Readings	θ_{600}	60.5313	lb/100ft^2
	n	0.72813	
	K	0.38958	
Power law constant	$a_{power-law}$	0.07584	
Power law constant	b	0.26968	
Power law constant	K_a	0.42431	

Appendix Figure 19: Fluid parameters

Casing point input parameters		
TVD	SG1	SG2
468	0	2.5
1402.7303	0	2.5
2651.8772	0	2.5
4140	0	2.5
5445.063545	0	2.5
	0	2.5
	0	2.5

Appendix Figure 20: Casing point calculations, used for graphical representations

	Length	Depth	$p_{BHP, static}$	$SG_{BHP, static}$			Δpann	$SG_{BHP,ann,dynamic}$	$p_{BHP, dynamic}$		$p_{backpressure}$	$p_{BHP, dynamic + backpressure}$	Safety Margins			
													Upper	Lower	Upper	Lower
	[m]	[m]	[bar]	[SG]	[bar]	[SG]	[bar]	[SG]	[bar]	[SG]	[bar]	[SG]	[SG]	[SG]	[bar]	[bar]
BHP	7357.14	5445.06	1048.72	1.84	1048.72	1.96	77.44	0.14	1126.16	2.11	1126.16	2.11	2.21	2.00	1182.47	1069.85
Interval 1	7357.14	5445.06	1048.72	1.84	1048.72	1.96	77.44	0.14	1126.16	2.11	1126.16	2.11	2.21	2.00	1182.47	1069.85
Interval 2	7357.14	5445.06	1048.72	1.84	1048.72	1.96	77.44	0.14	1126.16	2.11	1126.16	2.11	2.21	2.00	1182.47	1069.85
Interval 3	7357.14	5445.06	1048.72	1.84	1048.72	1.96	77.44	0.14	1126.16	2.11	1126.16	2.11	2.21	2.00	1182.47	1069.85
Interval 4	7357.14	5445.06	1048.72	1.84	1048.72	1.96	77.44	0.14	1126.16	2.11	1126.16	2.11	2.21	2.00	1182.47	1069.85
Interval 5	7057.14	5352.36	1031.97	1.84	1031.97	1.97	68.78	0.13	1100.75	2.10	1100.75	2.10	2.20	1.99	1155.78	1045.71
Interval 6	4807.14	4657.07	906.36	1.84	906.36	1.98	32.68	0.07	939.05	2.06	939.05	2.06	2.16	1.95	986.00	892.09
Interval 7	4807.14	4657.07	906.36	1.84	906.36	1.98	32.68	0.07	939.05	2.06	939.05	2.06	2.16	1.95	986.00	892.09
Interval 8	4790.00	4651.49	905.35	1.84	905.35	1.98	32.47	0.07	937.83	2.06	937.83	2.06	2.16	1.95	984.72	890.94
Interval 9	4532.86	4505.68	879.01	1.84	879.01	1.99	28.40	0.06	907.42	2.05	907.42	2.05	2.16	1.95	952.79	862.05
Interval 10	4532.86	4505.68	879.01	1.84	879.01	1.99	28.40	0.06	907.42	2.05	907.42	2.05	2.16	1.95	952.79	862.05
Interval 11	4190.00	4190.00	821.98	1.84	821.98	2.00	22.96	0.06	844.94	2.06	844.94	2.06	2.16	1.95	887.19	802.70
Interval 12	4140.00	4140.00	812.95	1.84	812.95	2.00	22.22	0.05	835.17	2.06	835.17	2.06	2.16	1.95	876.93	793.41
Interval 13	4140.00	4140.00	812.95	1.84	812.95	2.00	22.22	0.05	835.17	2.06	835.17	2.06	2.16	1.95	876.93	793.41
Interval 14	360.00	360.00	132.50	1.84	132.50	3.75	1.44	0.04	133.94	3.79	133.94	3.79	3.98	3.60	140.63	127.24
Riser	360.00	0.00	67.70	1.84	67.70	1.84	0.00	0.00	67.70	1.84	67.70	1.84	1.93	1.74	71.08	64.31

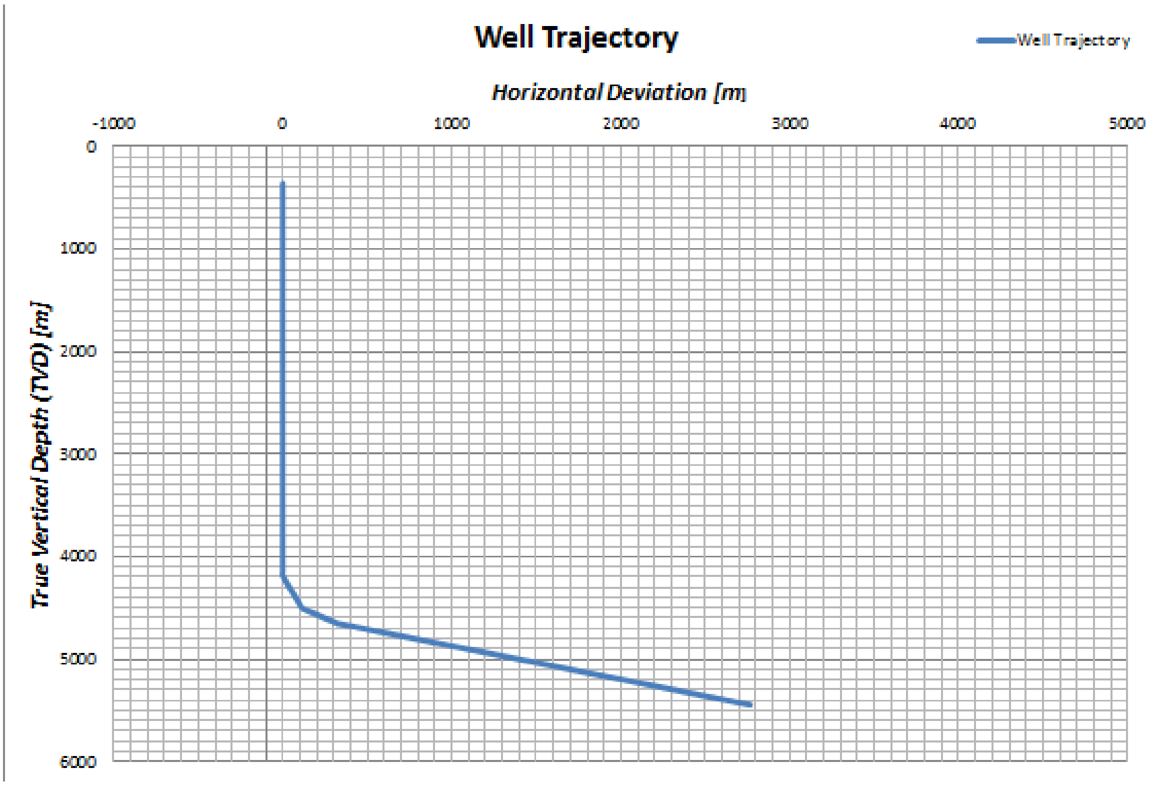
Appendix Figure 21: Pressure drop calculations

Frac Gradient						Mud Weight				Pore Pressure					
Depth	SG	Depletion	Dep. SG	Pressure		Depth	SG		Pressure	Depth	SG	Depletion	Dep. SG	Pressure	
[m]		[bar]		[Pa]	[bar]	[m]		[Pa]	[bar]	[m]		[bar]		[Pa]	[bar]
478.48	1.00	0.00	1.00	4692381.85	46.92										
475.32	1.02	0.00	1.02	4775523.11	47.76			0.00	0.00	478.46	1.00		1.00	4716049.34	47.16
481.14	1.07	0.00	1.07	5045800.35	50.46			0.00	0.00	505.42	1.06		1.06	5249987.85	52.50
493.03	1.11	0.00	1.11	5372791.27	53.73			0.00	0.00	556.55	1.13		1.13	6143270.73	61.43
504.91	1.15	0.00	1.15	5714530.04	57.15			0.00	0.00	622.81	1.20		1.20	7304841.01	73.05
525.92	1.19	0.00	1.19	6136561.86	61.37			0.00	0.00	695.22	1.25		1.25	8502335.23	85.02
543.88	1.23	0.00	1.23	6553029.58	65.53			0.00	0.00	758.61	1.29		1.29	9581433.58	95.81
567.95	1.26	0.00	1.26	7013556.57	70.14			0.00	0.00	828.06	1.33		1.33	10765644.90	107.66
610.09	1.31	0.00	1.31	7815042.17	78.15			0.00	0.00	888.47	1.36		1.36	11826898.16	118.27
667.30	1.37	0.00	1.37	8962041.21	89.62			0.00	0.00	939.83	1.38		1.38	12736537.77	127.37
739.68	1.43	0.00	1.43	10348972.31	103.49			0.00	0.00	1027.50	1.41		1.41	14233631.91	142.34
739.68	1.43	0.00	1.43	10348972.31	103.49			0.00	0.00	1103.03	1.45		1.45	15644779.85	156.45
784.93	1.46	0.00	1.46	11241479.89	112.41			0.00	0.00	1190.70	1.48		1.48	17246309.29	172.46
803.01	1.48	0.00	1.48	11645044.02	116.45			0.00	0.00	1293.50	1.51		1.51	19163172.51	191.63
833.21	1.49	0.00	1.49	12216547.08	122.17			0.00	0.00	1372.12	1.53		1.53	20658045.61	206.58
863.40	1.51	0.00	1.51	12806288.39	128.06					1471.92	1.56		1.56	22559177.01	225.59
896.59	1.54	0.00	1.54	13505104.78	135.05					1583.82	1.59		1.59	24734963.25	247.35
950.94	1.57	0.00	1.57	14619019.63	146.19					1689.69	1.62		1.62	26828957.27	268.29
993.22	1.59	0.00	1.59	15487934.32	154.88					1819.76	1.65		1.65	29441974.55	294.42
1038.50	1.62	0.00	1.62	16474925.63	164.75					1964.98	1.68		1.68	32363466.40	323.63
1111.00	1.65	0.00	1.65	18014635.07	180.15					2113.25	1.71		1.71	35378196.67	353.78
1207.70	1.69	0.00	1.69	20066719.37	200.67					2255.46	1.73		1.73	38347692.88	383.48
1313.47	1.74	0.00	1.74	22390165.63	223.90					2433.99	1.76		1.76	42116450.17	421.16
1413.20	1.78	0.00	1.78	24670758.60	246.71					2588.34	1.79		1.79	45359399.32	453.59
1561.33	1.83	0.00	1.83	28039389.06	280.39					2779.00	1.82		1.82	49482444.27	494.82
1685.29	1.87	0.00	1.87	30941361.92	309.41					2936.38	1.84		1.84	52875303.78	528.75
1812.30	1.91	0.00	1.91	33927477.75	339.27					3136.16	1.86		1.86	57198183.65	571.98
1945.35	1.95	0.00	1.95	37179040.65	371.79					3311.71	1.88		1.88	61099415.06	610.99
2111.71	1.99	0.00	1.99	41247926.40	412.48					3526.64	1.90		1.90	65845569.75	658.46
2235.72	2.02	0.00	2.02	44343143.08	443.43					3744.61	1.92		1.92	70594737.96	705.95
2368.84	2.05	0.00	2.05	47625305.26	476.25					3923.24	1.94		1.94	74476853.26	744.77
2538.25	2.09	0.00	2.09	51973605.45	519.74					4153.10	1.95		1.95	79528210.27	795.28
2671.38	2.11	0.00	2.11	55370000.05	553.70					4159.40	1.95		1.95	79631816.38	796.32
2868.06	2.15	0.00	2.15	60425882.32	604.26					4161.97	2.04	160.00	1.64	67096249.92	712.83

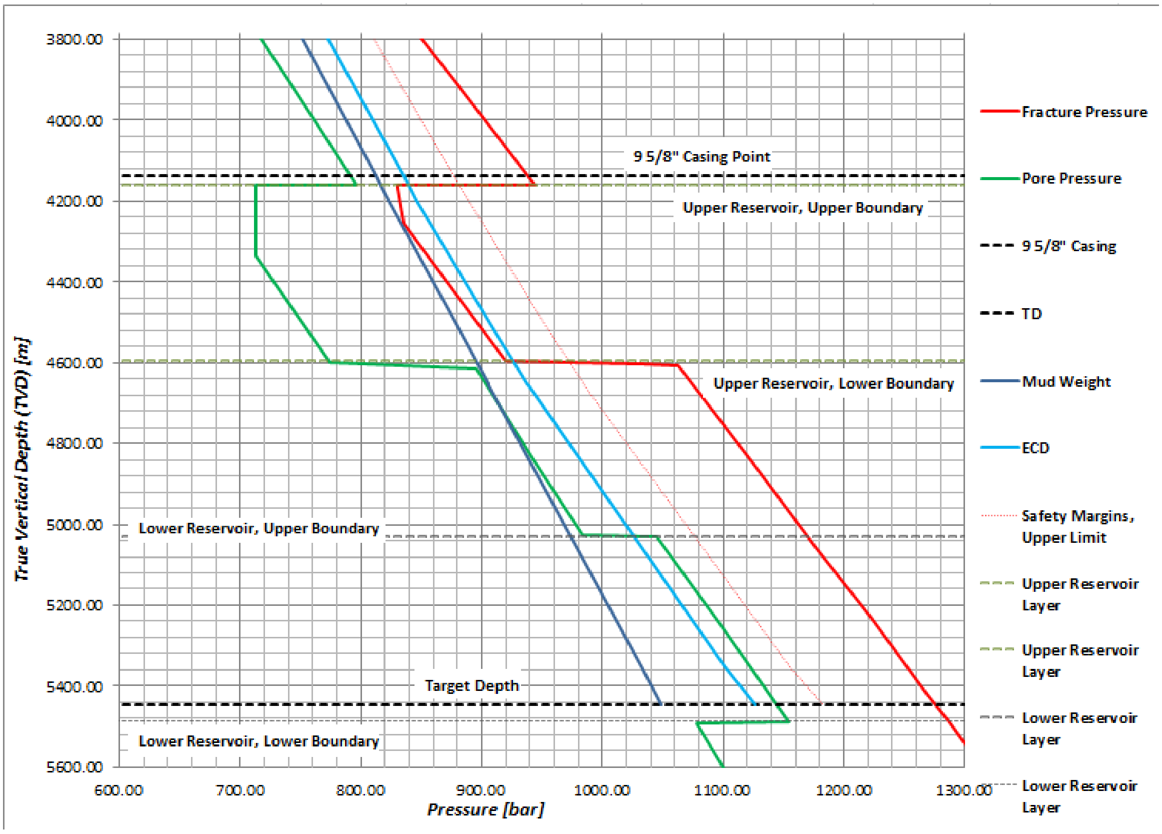
Appendix Figure 22: Reservoir parameters

		List Parameters			
				Casing/Pipe Diameters	Common Bit diameters
		N/A	0	4.5	3 7/8
Newtoniar	Turbulent	Riser	0.5	5	3 3/4
Bingham F	No	Cased Hole	1	5.5	3 7/8
Power-Law		Liner	1.5	6.625	4 1/2
		Pilot BHA	2	7	4 5/8
		Drill String	2.5	7.625	4 3/4
		BHA	3	8.625	5 5/8
			3.5	9.625	6
				10.75	6 1/8
				11.75	6 1/4
				13.375	6 1/2
				16	6 3/4
				18.625	7
				20	7 7/8
					8 1/2
					8 5/8
					8 3/4
					9 5/8
					9 7/8
					10 5/8
					11
					12 1/4
					14 3/4
					15
					17 1/2

Appendix Figure 23: List parameters



Appendix Figure 24: Graphical representation of the well trajectory



Appendix Figure 25: Graphical representation of the pressure regimes