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MASTER'S THESIS

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Through Tubing Rotary Managed Pressure Drilling

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Abstract

Managed pressure drilling (MPD) has been known to the industry for a few years. MPD with the ability of coping with risky down-hole pressure situations has gained a great deal of attention. Compared to MPD, the drilling method designated ‘’through tubing drilling’’ (TTD) is considerably younger. StatoilHydro, as one of the TTD pioneers, has drilled TTD wells in its North Sea assets, of which the majority have been the ‘’through tubing rotary drilling’’ (TTRD) wells.

The aim of initiating this technology was to access small and by-passed oil pools in mature assets in a cost effective manner, since TTRD rules out the need of pulling the well completion. From StatoilHydro’s experience we see that TTRD is one of the complex drilling methods. Drilling by this technique has seen a number of challenges and drilling problems. In fact, the majority of these problems are linked to system and down-hole pressure environments, and thus to drilling hydraulics.

Pressure induced drilling problems can be solved by application of MPD. The idea in this study is that the simultaneous application of TTRD and MPD will enable us to mitigate problems relating to pressure conditions and drill cost effective TTRD. Therefore, this thesis was initiated to study the hydraulics of ‘’through tubing rotary managed pressure drilling’’ (TTRMPD).

In this study two specially looked at MPD methods: back pressure and continuous circulation system allow for the reduction of the static mud weight in order to manage circulating mud weight and stay within available drilling window.

This study looks into hydraulics of the TTRMPD operation in terms of equivalent circulating density (ECD), hole-cleaning, extended reach ability. In the TTRD, ECD management is particularly challenging due to narrow annular clearance.

This master thesis focuses on the feasibility of combining MPD and TTRD to improve the ECD management in TTRD. We will look into the effects that the reducing mud weight may have on drilling parameters.

Table of contents

Abbreviation

API	=	American Petroleum Institute
API RP	=	American Petroleum Institute Recommended Practice
AFP	=	Annular Friction Pressure
BOP	=	Blow-Out Preventer
BPT	=	Back Pressure Technique
BHA	=	Bottom Hole Assemble
BHP	=	Bottom Hole Pressure
CPPPS	=	Crown Plug Profile Protection Sleeve
CPP	=	Crown Plug Profile
CTD	=	Coiled Tubing Drilling
CCS	=	Continuous Circulation System
CTR	=	Cuttings Transport Ratio
DAPC	=	Dynamic annular pressure control
DHSV	=	Down-Hole Safety Valve
DBR	=	Daglig Bore Repport
ECD	=	Equivalent Circulating Density
HIF	=	Hydraulic Impact Force
IPM	=	Integrated Pressure Management
KOP	=	Kick-Off Point
KBR	=	Rotary Kelley Bush
MW	=	Mud Weight
MPD	=	Managed Pressure Drilling
MD	=	Measured Depth
NPT	=	None Productive Time
NRV	=	None-Return Valve
OH	=	Open Hole
PDC	=	Polycrystalline Diamond Compact
PWD	=	Pressure While Drilling
RCD	=	Rotating Control Device
ROP	=	Rate of Penetration
TTD	=	Trough Tubing Drilling
TTRD	=	Trough Tubing Rotary Drilling
TD	=	Total Depth
TFA	=	Total Flow Area
TTRMPD	=	Through Tubing Rotary Managed Pressure Drilling
TVD	=	True Vertical Depth
Warp	=	Weighting Agent Research Project

List of symbols

a	=	constant
A	=	Robertson and Stiff model parameter similar to k (lbf sec^B/100 ft^2)
A_c	=	characteristic area of the particle (in^2)
b	=	constant
BHP	=	bottom-hole pressure
B	=	Robertson and Stiff model parameter similar to n (dimensionless)
C	=	Robertson and Stiff model correction factor (1/sec^B)
C_a	=	cuttings concentration (%)
CTR	=	cuttings transport ratio (%)
d_p	=	diameter of cuttings (in)
$\left(\frac{dp}{dL}\right)_p$	=	pressure loss per unit length of pipe (psi/ft)
$\left(\frac{dp}{dL}\right)_a$	=	pressure loss per unit length of annular section (psi/ft)
D_p	=	pipe diameter (in)
D_b	=	bit diameter (in)
D_1	=	ID of annulus (in)
D_2	=	OD of annulus (in)
D_h	=	hydraulic diameter for annulus (in)
D_n	=	bit nozzle diameter (in)
e	=	eccentricity (dimensionless)
E	=	Young's module (psi)
ECD	=	equivalent circulating density (ppg)
F	=	net force exerted on the particle as a result of gravity and buoyancy
f_p	=	friction factor in pipe (dimensionless)
f_a	=	friction factor in annulus (dimensionless)
f_p	=	particle friction factor (dimensionless)
k	=	consistency index (lbf sec^n/100 ft^2)
k_p	=	consistency index in pipe (lbf sec^n/100 ft^2)
k_a	=	consistency index in annulus (lbf sec^n/100 ft^2)
L	=	length of pipe or length of annular section (ft)
n	=	flow behaviour index (dimensionless)
n_p	=	flow behaviour index in pipe (dimensionless)
n_a	=	flow behaviour index in annulus (dimensionless)
N	=	rpm (rotation per minute)
P_{bp}	=	back pressure (psi)
P_{mw}	=	pressure exerted by mud weight (psi)
P_{AF}	=	annular friction pressure (psi)
P_o	=	pore pressure (psi)
P_f	=	fracture pressure (psi)
ΔP_p	=	pressure loss in pipe (psi)
ΔP_a	=	pressure loss in annulus (psi)
ΔP_b	=	pressure loss across bit (psi)
ΔP_t	=	total pressure loss in drilling system (psi)

ΔP_o	=	pore pressure change (psi)
ΔP_f	=	fracture pressure change (psi)
ΔP_R	=	pressure loss due to rotation (psi)
Q	=	flow rate (gall/min)
R_{600}	=	reading from rheometer at 600 rpm
R_{300}	=	reading from rheometer at 300 rpm
R_6	=	reading from rheometer at 6 rpm
R_3	=	reading from rheometer at 3 rpm
R_{100}	=	reading from rheometer at 100 rpm
Re	=	Reynolds number (dimensionless)
Re_p	=	particles' Reynolds number (dimensionless)
Re_L	=	laminar boundary (dimensionless)
Re_T	=	turbulent boundary (dimensionless)
R	=	multiplication factor accounting for eccentricity (dimensionless)
R_{lam}	=	multiplication factor accounting for eccentricity in laminar zone
R_{turb}	=	multiplication factor accounting for eccentricity in turbulent zone
ROP	=	rate of penetration (ft/h)
TVD	=	true vertical depth (ft)
T_p	=	particle thickness (in)
TFA	=	total flow area (in^2)
V_{p}	=	fluid velocity in pipe (ft/s)
V_{a}	=	fluid velocity in annulus (ft/s)
V_{ac}	=	annular critic velocity (ft/s)
V_{s}	=	slip velocity of cuttings (ft/s)
V_{n}	=	nozzle velocity (ft/s)
V_{r}	=	cuttings rise velocity (ft/s)
$V_{\mathrm{T(p)}}$	=	transition velocity in pipe (ft/s)
$V_{\mathrm{T(a)}}$	=	transition velocity in pipe (ft/s)
γ	=	shear rate (1/sec)
γ_{min}	=	minimum shear rate value of data (1/sec)
γ_b	=	boundary shear rate (1/sec)
γ_p	=	shear rate corresponding to τ_p (1/sec)
γ_{max}	=	maximum shear rate value of data (1/sec)
γ^*	=	shear rate value corresponding to the geometric mean of the shear stress τ^* (1/sec)
μ_a	=	apparent viscosity (cp)
μ	=	viscosity (cp)
μ_p	=	plastic viscosity (cp)
ρ_f	=	weight of drilling fluid (ppg)
ρ_e	=	effective weight of drilling fluid (ppg)
$\rho_{e(c)}$	=	effective weight of drilling fluid due to cuttings (ppg)
ρ_p	=	weight of rock particles (ppg)
τ_{min}	=	minimum shear stress value of data (lbf/100 ft^2)
τ_{max}	=	maximum shear stress value of data (lbf/100 ft^2)
τ_p	=	shear stress developed by particles (lbf/100 ft^2)
τ^*	=	geometric mean of the shear stress (lbf/100 ft^2)
τ	=	shear stress (lbf/100 ft^2)
τ_y	=	yield stress (lbf/100 ft^2)

τ_o	=	yield stress in Herschel-Bulkley, Unified and Robertson-Stiff models (lbf/100 ft^2)
τ_{yL}	=	lower shear yield stress in Unified model (lbf/100 ft^2)
$\varepsilon_{x,y,z}$	=	strains along X, Y, Z axis (dimensionless)
$\sigma_{x,y,z}$	=	stresses along X, Y, Z axis (psi)
$\sigma_{H,h,o}$	=	maximum horizontal, minimum horizontal and overburden stresses (psi)
v	=	Poisson's ratio

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1 Introduction

Slot recovery drilling in mature fields has become a challenge because of tight pressure margins caused by reservoir depletion. Likewise, TTRD enables reduced cost of accessing by-passed reserves in mature fields that is likely to be challenged by narrow pressure envelops. Narrow drilling window and high pressure losses due to small annular clearance make it a big challenge to manage the ECD within narrow operational envelop. Two major consequences of exceeding fracture gradient by ECD are lost circulation and unintentional formation breakdown. To avoid occurrence of these problems, the MPD as an advanced drilling technique has come to play.

In this work, we look into the hydraulic issues of coupling MPD with TTRD. Focus is on drilling problems concerning hydraulics during drilling of a TTRD well and on how to eliminate these problems by integrating MPD into TTRD. Our concern is platform TTRD and MPD techniques suited for platform applications.

ECD management, pressure loss issues, hole-cleaning performance, wellbore stability and extended reach ability of TTRD are studied in a scenario coupled with MPD. For this purpose Wellplan, Drillbench and Matlab softwares have been utilised.

Structure for this thesis starts from providing necessary theoretical and practical background and moves towards problem description, analysis performed, discussion, conclusions and recommendations for future work.

2 Through Tubing Drilling (TTD)

2.1 General Insight into TTD

The oil industry has always been searching for new technologies, particularly within the drilling engineering sphere. TTD is one of these technologies aimed to overcome the economic constraints of conventional drilling in mature assets. TTD is accepted by the drilling industry as a cost-effective method of accessing accumulations of hydrocarbons in some mature fields. It has proven to be an important tool in maximizing remaining recovery through low cost infill drilling for previously uneconomic and therefore bypassed pockets of oil and gas. The technique involves running a window milling assembly through an existing Christmas tree and completion. No components of the completion are removed and drilling takes place through the existing completion tubing and that is why the technique is called through tubing drilling. A slim-hole is drilled into the reservoir of the interest. Often a liner is run, cemented and perforated. All of the operations are carried out through the existing completion, eliminating the time and cost associated with pulling the old completion and then running a new completion and tree when the drilling phase is complete.

TTD is split into two categories, ‘’Through Tubing Rotary Drilling (TTRD) and ‘’Through Tubing Coiled Tubing Drilling’’ or in short ‘’Coiled Tubing Drilling’’ (CTD). TTD can therefore be conducted by using jointed pipe or coiled tubing. Throughout this study, the reference to the methods of TTD is TTRD and CTD. Both of the methods have been used in the oil industry across the world. In the North Sea, however TTRD is the most common technique. In this study, only operations conducted in the North Sea are looked at, particularly on the Norwegian sector. StatoilHydro can be said to be one of the pioneers of the TTRD operations in the Norwegian sector of North Sea.

2.2 Through Tubing Rotary Drilling (TTRD)

TTRD is a drilling technique that utilizes jointed drill pipe, components of rotary drilling and conventional sidetracking. To drill a sidetrack using rotary drilling equipment is well known to the drilling industry. However, the operation TTRD entails is different from conventional drilling and sidetracking in many ways. There are a number of requirements to be met for a TTRD well to be drilled as safely and cost efficiently as possible. TTRD is most often performed from drill rigs such as platform, semisubmersible and jack-up, however can potentially be conducted from drill ship as well. The drilling equipment is rigged up on top of the Christmas tree up to the drill floor. The drill string passes through the Christmas tree, tubing hanger and tubing down to the predetermined kick-off point (KOP). Typical TTRD operations have been performed through 5’’ and 7’’ tubing. The following is a drawing of a TTRD well drilled by KCA DEUTAG Drilling Ltd in the UK sector of North Sea.

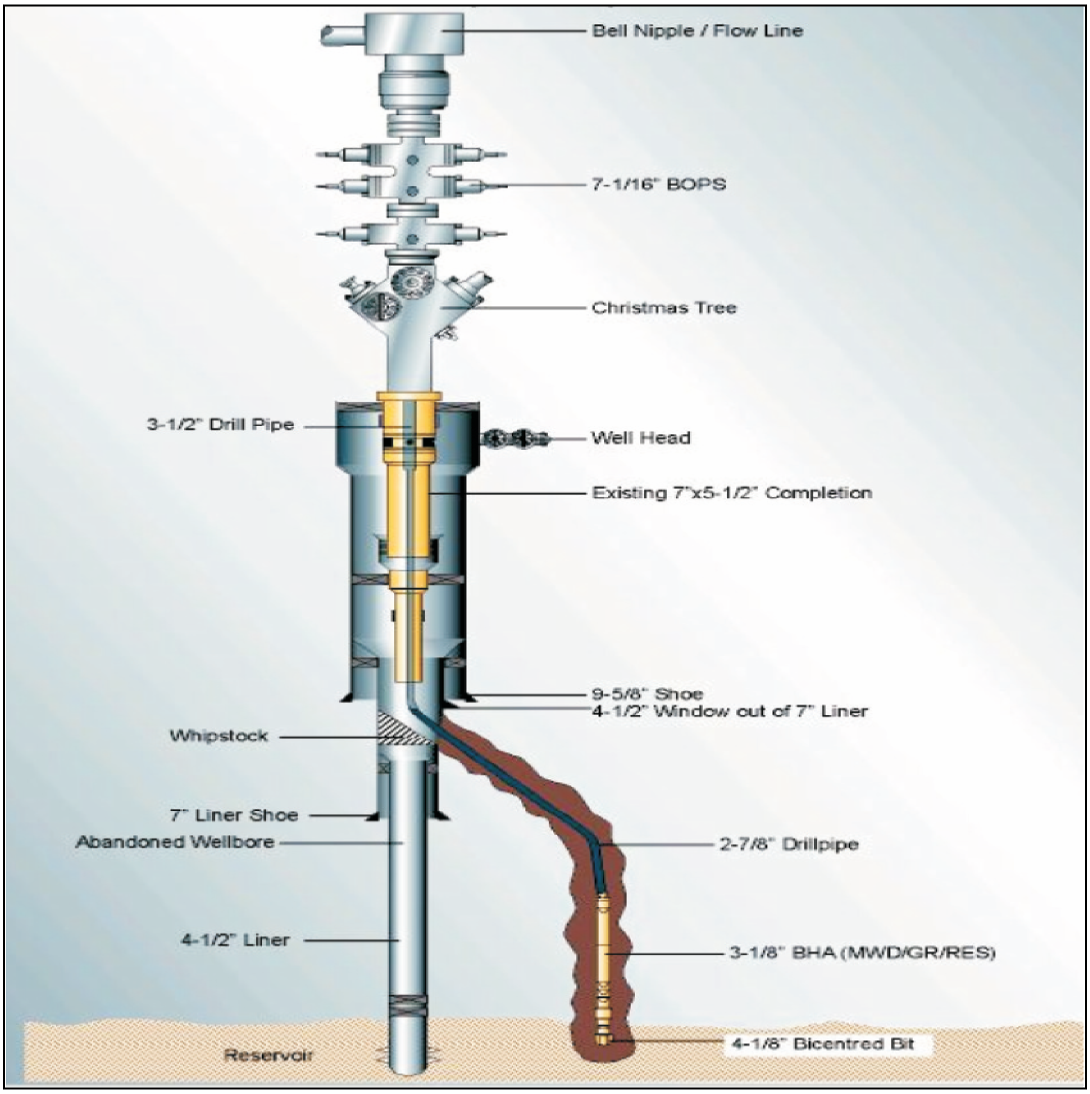


Figure-2.1: Through tubing rotary drilling schematic[7]

As seen from Figure-2.1, the mother well-bore has been plugged and abandoned. After having whip-stock set in place, a directional TTRD has been drilled through the 7'' liner, where the completion string consists of 7''x5 ½'' tubing. After kicking off, the sidetracked well path continues to its intended target.

2.2.1 Drillpipes Used in TTRD Operations

Drill pipe size that is typically being used in TTRD varies from 2 7/8'' to 3 ½''. In the selection of drillpipe, the main determining factor is tubing size and as big as possible drillpipe is to be used. Likewise, while selecting the drillpipe apart from its size, pipe strength, stiffness, operability and availability issues need to be looked at. In TTRD, drillpipes must be fatigue resistant (because of high doglegs) and as less damaging as possible to the completion.

The pipe handling procedures and requirements can vary from company to company. In StatoilHydro, there are dedicated documentations addressing this matter. For instance, the document titled ‘’ Best Practice – Through Tubing Drilling and Completion’’ details this matter even further.

2.2.2 Drilling BHA and Its Components in TTRD

BHA used is pretty much the same as it is in the normal directional drilling. However, the size of it is limited by inner ID of the completion tubing in place. Typical BHA used in through tubing rotary drilling is listed as below:

- Bit (largest size utilized in TTRD wells is 5 7/8’’)
- Mud motor (today, in StatoilHydro rotary steerable systems are used)
- Measurement/logging while drilling tools, pressure/temperature sensors and etc
- Hydraulic Jar
- Heavy weight drill pipe
- Piggy back sub (running tool for wear sleeve)

BHA handling procedures and requirements need to be followed up carefully because of fact that BHA components may be more vulnerable than any other components of drill string. Before running in hole, OD of all BHA and drill string components must be checked and verified that, it will pass through the minimum excepted ID within the borehole.

2.2.3 Window Milling

Milling a TTRD window is done in the same manner as for a normal drilling operation. First, the mother well-bore is plugged and abandoned for the purpose of well control and well integrity. In addition to plugging the main wellbore, cement isolation against reservoir needs to be verified (usually in the annulus of 7’’ liner). This will reduce the complexity of well control whilst drilling through tubing. Without this isolation the well will likely be in a one-barrier situation, both in the drilling and production phases. After having the main wellbore plugged and isolated, whip-stock is run in to a depth of interest and set. Usually, in TTRD operations the KOP (exit point) is linked to production packer setting depth.

StatoilHydro’s policy concerning TTD operations dictates that KOP shall be below the packer to maintain well integrity. The requirement is that annulus isolation from exit point up to the previous casing shoe needs to be 200 m good cement or 50 m cement verified by the cement bond log. Otherwise, wellbore pressure barriers will likely not be met as required. However, recently evolving project (’’exit over production packer’’) in StatoilHydro shows that there is a potential for kicking off above the production packer in TTD wells and still being able to sustain well integrity. Figure-2.2 illustrates whip-stock placement and window milling process.

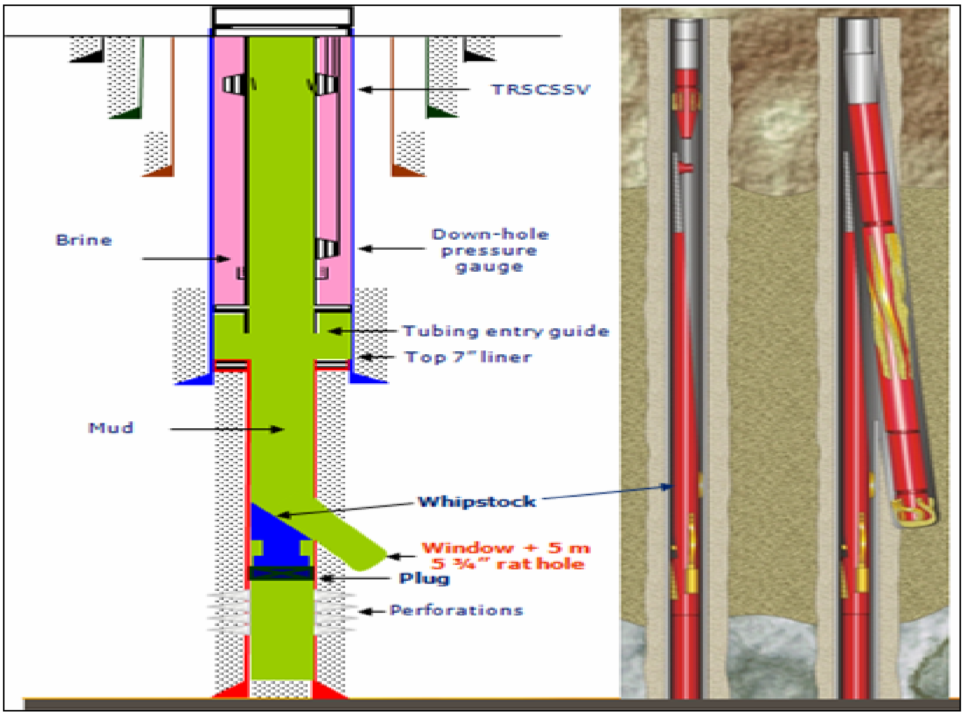


Figure-2.2: Window milling schematic[32]

Window milling process should be done with as few runs as possible and several systems are designed for one trip only. The milling BHA needs to be designed for the worst case scenario that can be expected in the well. Three main types of milling tools are used for TTRD wells that are listed as follows:

- Crushed carbide
- Tungsten carbide inserts (can be combined with PDC inserts)
- PDC (and diamond speed mill)

Depending on hardness of the formation to be drilled for rat-hole purpose, crushed carbide is used for soft formations, tungsten carbide inserts for middle hard and PDC for hard formations. While designing window milling, particular attention should be paid to choosing components that are as little damaging as possible to the completion, wellbore seals and its integrity. The above mentioned milling tools can be compared against one another in terms of their cost, down-hole performance and destructiveness against well completion elements. On another hand, the formation will most often decide the mill selection.

2.2.4 Protection of Completion Elements

During a TTRD operation, there is a strong need for protecting a number of completion elements against wear and tear scratch. Leaving vulnerable completion components unprotected could lead to further well operations because of risk of damaging well integrity. The most susceptible elements of completion while performing a through tubing drilling are:

- Christmas tree
- Well head area
- Down-Hole Safety Valve (DHSV)

The tool called wear protection sleeve is installed inside the DHSV to preserve it. By the experience of StatoilHydro, one of the known protection sleeves and reliable to use is the one produced by Red Spider. In Figure-2.3, the picture to the left is a demonstration of the down-hole safety valve in place, the picture to the right demonstrates the protection sleeve run and set. The sleeve is run on a dedicated running tool, which has been designed for use with through tubing rotary drilling and is used to run the Red Spider safety valve TTRD protection sleeve in a piggy back mode. The running tool is designed to function as a part of the drillstring. It carries TTRD protection sleeve into the well and picks it up upon retrieval from the well. The device was developed specifically for use on TTRD operations but can be used in a number of other applications where the protection of seal bores is required. In Figure-2.4, the illustration to the left shows the already set sleeve and drill string working through it.

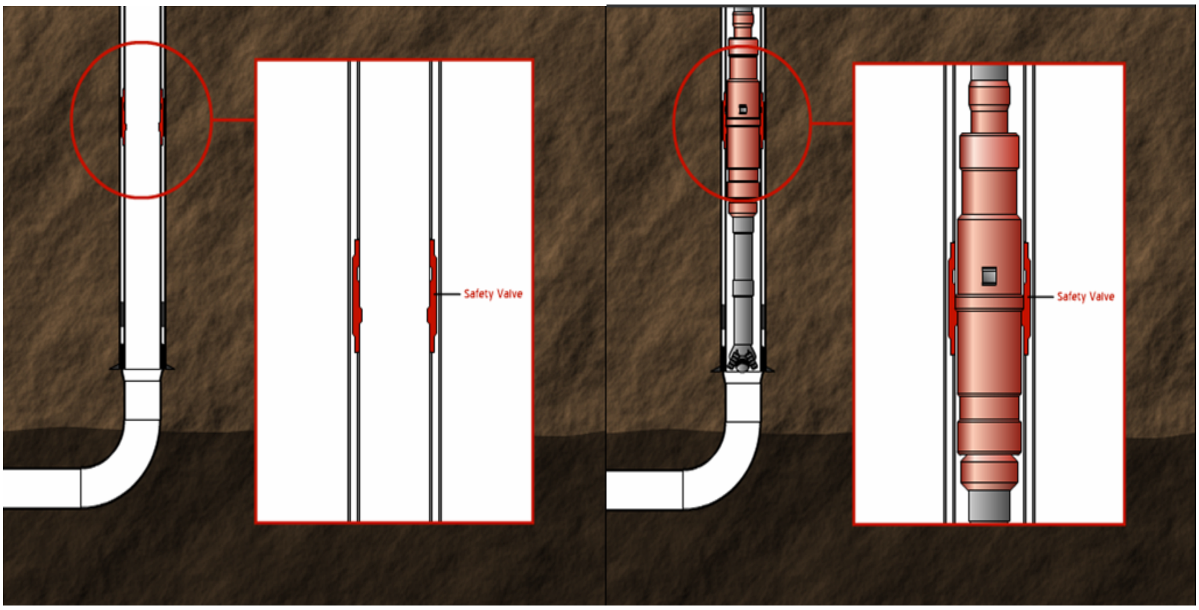


Figure-2.3: Safety valve and wear protection sleeve drop off [31]

The demonstration to the right in Figure-2.4 shows the retrieval of the wear sleeve while pulling the drill string out of hole. The running tool both installs the sleeve on the way in and retrieves it on the way out. The Red Spider manufactured wear sleeve is used to protect seal bores located within down-hole tubing mounted safety valves, safety valve nipples or X-mas trees

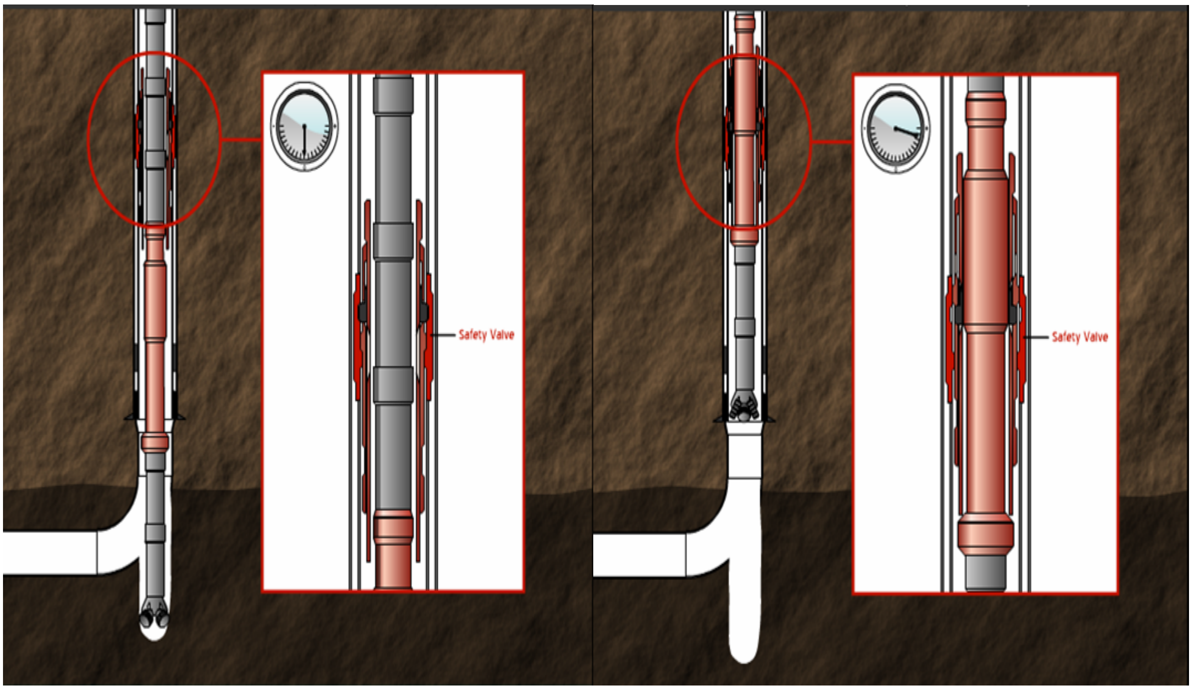


Figure-2.4: Wear protection sleeve set and retrieval[31]

2.3 Coiled Tubing Drilling (CTD)

Coiled tubing is a continuously-milled tubular product manufactured in lengths that requires spooling onto a take-up reel. CTD has been used by the oil industry for quite a long time and has been extensively used in many parts of the world, especially in Alaska, USA. Tubing size typically ranges from 1 inch to 4 inch in diameter. The basic BHA components used in CTD are:

- Bit (tri-cone and PDC)
- Mud motor
- Measurement/logging while drilling and other directional drilling equipment
- Temperature and pressure and other down-hole sensors
- Orienting sub

Use of CTD has got a number of positives. For instance, operational time is considerable reduced in CTD by eliminating pipe connections. Along with this, CTD has the following advantages:

- Small foot print
- Quick trip time
- Potentially lower cost mobile rigs (on platform, TTRD is less expensive than CTD)
- Can operate simultaneously with the rig

However, as naturally CTD has got its drawbacks and limitations as well. In formations prone to sloughing or washing out coiled tubing is not appropriate. If the wellbore stability problems develop coiled tubing cannot be rotated nor can it withstand the stress that conventional drill collar and drill pipe can. Due to strength and weight of coiled tubing horizontal drilling reach and hole size are generally less than for the conventional equipment. Within the frame of limitations disadvantages of CTD are

- Inability to rotate
- Limited weight on bit
- Limited extended reach capability
- Tubing fatigue
- Easy to stuck

Apart from this, portable capability of CTD equipment can be difficult in offshore environments and can require modification of rig facilities.

2.4 Subsea TTD

Development of a TTRD technology provides a more cost effective method to increase production from subsea wells compared to drilling and completing new wells. Subsea TTRD is more challenging than the platform based operations. One of the major challenges in subsea TTRD is the rig movement. This makes rig heave and riser centralization problems that are crucial for proper protection of completion while running in and out with the drillstring and even during drilling. In subsea wells a pre-installable nipple protector is used to preserve the well head components against scratches from mill and bit when running in with the BHA. Nipple protector is run and retrieved on a dedicated wire-line or drillpipe running and retrieving tool. However, nipple protector is not supposed to withstand continuous rotation forces since it is very thin in thickness. To cope with the rotational forces Crown Plug Profile Protection Sleeve (CPPPS) has been developed. CPPPS protects the crown plug profile area of the X-tree. It is usually conveyed in a piggy back sub on TTRD running tool together with the safety valve TTRD protection sleeve. The running tool is designed to function as a part of the drillstring. It carries both the CPP and TTRD protection sleeves into the well and retrieves them on the way out.

Another problem in subsea TTD is heave compensation. Because of the light weight of string, rig heaving challenges landing and pulling of protection sleeves. To address this, a careful planning is needed. For handling the optimum heave compensator training the rig personnel should be considered.

2.5 TTD Summary

In TTD drilling equipment are topped upon the Christmas tree. The sequence of equipment to be rigged up varies from subsea to platform wells and is as follows (bottom to top)

For platform wells

- High pressure riser
- Drilling BOP
- Bell nipple

For subsea wells

- Drilling BOP
- Marine riser
- Bell nipple

For subsea wells (new)

- Low Riser Package
- High pressure riser
- Subsurface BOP
- Bell nipple

TTD has been known as a cost efficient infill drilling technique commonly applied in matured fields. However, it is evolving as the time passes new equipments and experiences are emerging. In North Sea and across the world many of the oil companies have gained an appreciable experience on this sphere. This innovative drilling method enables operators around the world to increase their recovery by accessing to by-passed and isolated reservoir pockets. TTRD technology enables new drainage points from an existing well through

- Safer operation (No additional tree required and less tubular handling)
- No pulling of the tubing or X-mas tree saves time and cost. (reuse of initial capital expenditure)
- Deeper kick off point (saves drilling and completion costs)

While various benefits from several angles can be

Financial benefits

- Lower cost than conventional drilling operation
- Increased income from each well
- Extended well life
- May enable production from marginal fields
- Maximizes production from mature fields

Operational benefits

- Less time spend for operations
- No anchor handling required if dynamical positioning vessel is utilized
- Time effective, typical operation 3 weeks 1000 – 1500m horizontal reservoir drilling
- Possible to combine multilateral wells with TTRD

Environmental benefits

- Environmental friendly (smaller drilling fluid volumes required)

- Safe infill drainage points

Risk benefits
- Less handling of heavy equipment
- Campaign based operations with well trained crew

To detail all available TTD technology, equipment and experience step by step is beyond the intention of this study, therefore those who are interested can refer to the StatoilHydro Best Practice TTD&C[1] and some other relevant TTD literature.

3 Managed Pressure Drilling (MPD)

3.1 Introduction to Managed Pressure Drilling and Definitions

Managed Pressure Drilling, as a discipline or drilling technique is the result of high cost of Non-Productive Time (NPT) caused by drilling problems originating primarily from the close proximity between pore pressure and fracture pressure. MPD is a general description of methods for well-bore-pressure management and control. MPD includes a number of ideas that describe techniques and equipment developed to limit well kicks, lost circulation and differential pressure sticking. It may also reduce the number of additional casing strings required to reach the Total Depth (TD) since it may allow for longer open-hole sections to be drilled. Field of well-bore pressure management has broad application in the drilling industry and supplies solutions to problems:

- Number of casing strings and subsequent hole size reduction.
- NPT associated with differentially stuck pipe
- NPT associated with lost circulation – well kick sequence.
- Drilling with the total lost circulation
- Limited rate of penetration.
- Deepwater drilling with lost circulation and water flows.
- Enable drilling where normal drilling is not possible, i.e. where the window between pore pressure and fracture pressure is small.

The International association of drilling contractors subcommittee on the underbalanced and balanced pressure drilling has made the following formal definition of managed pressure drilling: MPD is an adaptive drilling process used to more precisely control the annular pressure profile throughout the well-bore. Hence, the objectives are to ascertain down-hole pressure boundaries, control and manage annular pressure profile accordingly and within the pre-defined pressure margin. This may include control of back pressure by using a closed and pressurized mud return system. Though not stated in the formal definition but implied is that this enabling drilling technology uses a single-phase drilling fluid treated to result in as low annular frictional pressure drop as possible. MPD provides a valuable help in managing massive losses associated with drilling fractured reservoirs. It enables us to reduce ECD (equivalent circulating density) problems while drilling extended reach wells and particularly wells with narrow operable pressure margin. This is known as drilling window between pore and fracture gradients. As stated in the definition, MPD is an *adaptive process* of drilling that suggests that the drilling program, plan and procedure are changeable and will be changed as the conditions in the wellbore dictate so. MPD is a common name standing for a drilling method under which several existing techniques are available. These techniques are:

- Back pressure technique that basically implies constant bottom-hole pressure maintenance adjusting back pressure by choke at surface.
- Continuous circulation system which means that circulation is also maintained during pipe connection.

- ECD reduction tool, this is a special tool designed to use as a part of drilling string to reduce ECD.
- Pressurized mud-cap drilling that refers to drilling without returns to the surface.
- Dual gradient technique, this is the general term for a number of different approaches to control up-hole annular pressure by managing ECD in deepwater offshore drilling.

Except first two the rest will be briefly mentioned. In general, any of the above MPD techniques aims to control and manage annular and thus bottom-hole pressure.

3.2 Back Pressure Technique (BPT)

3.2.1 General

In this technique of MPD, the purpose is to maintain a constant Bottom-Hole Pressure (BHP) throughout drilling. The idea behind the technique is to apply back pressure in annulus to maintain BHP at desired level both during drilling and pipe connections. The narrow operable window between pore and fracture pressures is usually a case in mature fields. In many cases this is caused by reservoir pressure depletion that leads to close proximity between pore and fracture pressures over time. This phenomenon is addressed in Section-5.

A small pressure margin for the drilling can also be the result of abnormally or sub-normally pressurized subsurface formations and reservoirs. In these cases, we need proper pressure management technique and procedure to sustain ECD within drilling window. Pressure challenging wells may not be drilled in a conventional manner or if drilled they become cost ineffective because of drilling problems such as lost circulation, differential sticking. Back pressure technique allows for a reduction in mud weight and compensates for this reduction while drilling and making connections accordingly and therefore manages BHP at desired level.

3.2.2 BHP in Conventional Drilling Mode

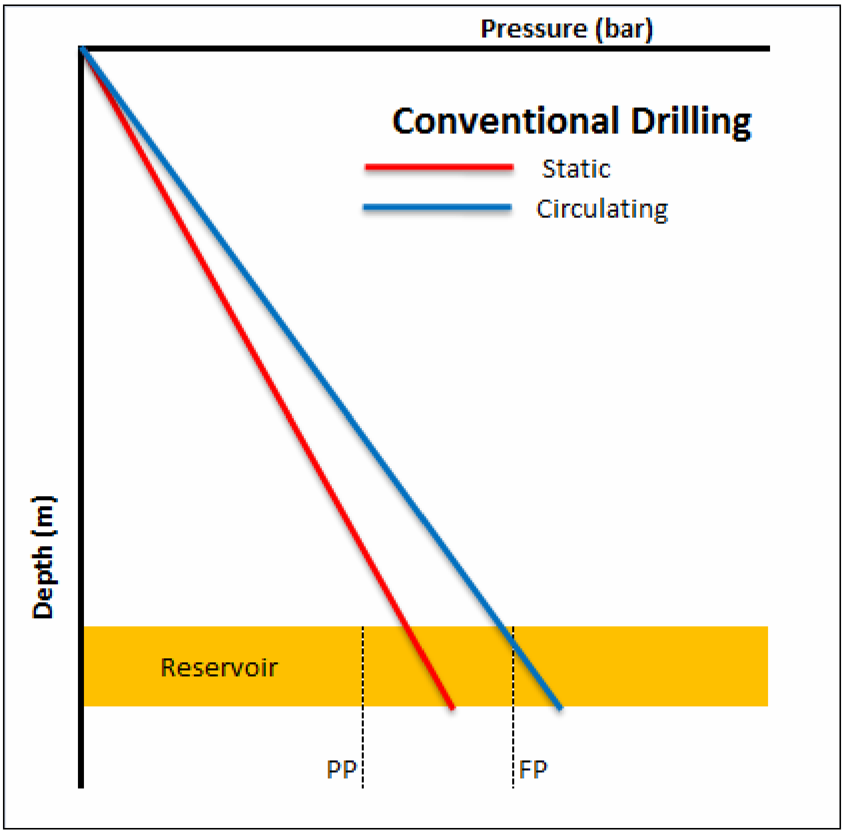
In conventional drilling, BHP is defined by two parameters when mud is in circulation. One is the static Mud Weight (MW) and the other is the Annular Friction Pressure (AFP). In this case, BHP equation is defined as follows:

$$BHP_{dynamic} = P_{mw} + P_{AF} \tag{3.1}$$

When circulation ceases for pipe connection the above equation reduces to

$$BHP_{static} = P_{mw} \tag{3.2}$$

AFP is function of a number of parameters such as well/drilling string geometry, flow rate, cuttings loading and fluid rheology. In conventional drilling, mud weight needs to be greater than the lower pressure boundary defined by pore pressure. In wells having a small operable window ECD will easily exceed the upper pressure boundary defined by fracture pressure that consequently leads to loss circulation and NPT. Figure-3.1 shows how this occurs while drilling a particular reservoir section having a tight margin.



Firgure-3.1: Conventional drilling and BHPs

3.2.3 BHP in MPD Back Pressure Drilling Mode

In back pressure drilling, a reservoir might be overbalanced, balanced or even underbalanced. That is, mud weight may be greater than pore pressure, equal to it or slightly be less than it depending upon the situation. The philosophy is to reduce the mud weight and BHP while drilling through a tight widow. In this case, the BHP equation is written as:

$$BHP_{dynamic} = P_{mw} + P_{AF} + P_{bp} \tag{3.3}$$

When the drilling is stopped for making pipe connection, Eq. (3.3) simplifies to the following equation.

$$BHP_{static} = P_{mw} + P_{bp} \tag{3.4}$$

Back pressure at the surface can be adjusted by choke manifold with presence of back pressure pump to maintain BHP at needed level. Figure-3.2 illustrates the drilling process where MPD used to drill through tight drilling widow that was not drillable conventionally.

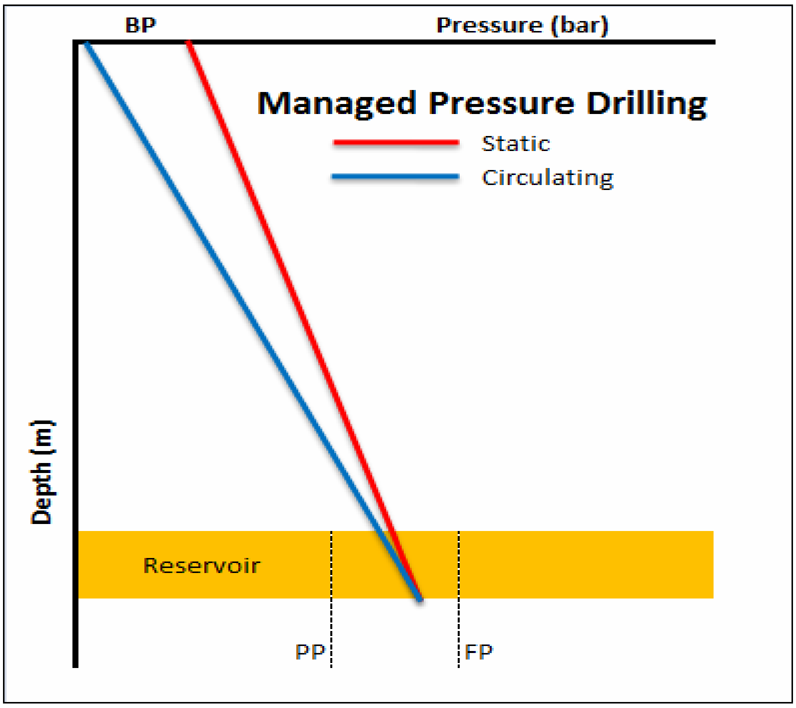


Figure-3.2: MPD and BHP management

In this case back pressure applied is dependant on the down-hole pressure conditions. In situation of a stopped circulation the engaged hydraulics model automatically defines back pressure based on pore/fracture pressures values. Defined back pressure is applied by use of choke manifold and back pressure pump.

3.2.4 Equipment for Back Pressure Technique

In conventional drilling, drilling fluid return is received at atmospheric condition on surface. For this reason conventional drilling is an open vessel system. Annular pressure management is primarily controlled by the mud density and mud pump flow-rate.

In addition to conventional drilling MPD uses several other equipments. It uses a specialized manifold that includes redundant chokes, flow-meter, data acquisition and control electronics.

Some sources presents that MPD leaves small footprint. The experience of StatoilHydro shows that footprint issue has been a problem in some situations.

MPD equipments add a modification to rig-up sequence from well head up to drill floor and facility layout on the derrick. Special equipments for MPD back pressure technique in addition to normal drilling equipment are:

- Rotating Control Device (RCD), also known as rotating control head
- Back pressure pump
- Choke manifold
- Non-return valve
- Pressure While Drilling (PWD) tool

Rotating Control Device: RCD is a common to all MPD techniques since it is required that the annulus must be packed off at the surface. Annular preventer or a pipe ram can do this as temporary measure. The industry has come to depend on a rotating control device or rotating annular preventer to limit rotational wear during drilling. There are special versions of the RCD for use in different drilling applications.

Morden RCDs typically operate at pressures up to 5000 psi (344.7 bar) static and 2500 psi (172.4 bar) when rotated. RCD is a rotating packer that uses an annular seal element or ’’stripper rubber’’ that is 1/2’’ to 7/8’’ (12.7 -22.2 mm) diameter undersize to the drill pipe. It forms a seal in zero pressure conditions.

The sealing element also serves as a barrier between wellbore fluid and rig floor personnel. The illustration to the left in Figure-3.3 shows a rotating control head - HOLD™ 2500 made by Smith International. The rubber element seen in black colour seals around drill pipe and prevents fluid movement upwards through annulus.

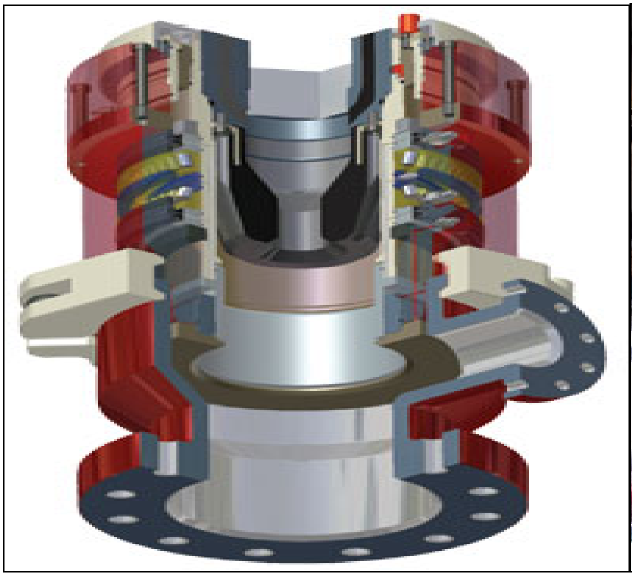



Figure-3.3: Rotating control device[33 & 34]

The element is exposed to well-bore pressure and main sealing is done by the force of annular pressure (well pressure actuation). Build-up of annular pressure against the element exerts a direct sealing pressure on a per-unit-area basis against the stripper rubber. The annular seal element is forced onto joint of pipe using a special pointed sub. The annular seal rotates with pipe and is locked into the bearing assembly. The bearing pack is lubricated and cooled by a circulating hydraulic system.

Driller doesn't need to take any action during drilling or stripping operations. The seal rubber responds to annulus pressure. When stripping is no longer required the rotating seal assembly is released from the bearing pack and drill-pipe stand holding the assembly is set aside. When stripping in hole the seal element is lubricated by keeping the bowl on top of the rotating element full of water (or oil).

The illustration to the right in Figure-3.3 displays placement of RCD. The device is usually landed over the BOP. RCD are available in different design and specifications. For instance, the high pressure RCD introduced by Weatherford uses dual stripper rubbers; upper element and lower element. The upper stripper is a backup against seal leak from wear in the lower element. The lower stripper rubber takes the pressure differential, does most of the sealing and has about 60% of wear in comparison to the upper. The RCD's main components include the flow spool or lower bowl with inlet, outlet flanges, the bearing assembly and drive bushing assembly.

Note that two forms of RCD are known such as passive and active. In active RCD sealing is more effective than in passive RCD. By use of its own hydraulic forces active RCD can force sealing elements to be squeezed on the pipe that will reduce any leakage chances. Passive RCD lacks this ability and the sealing elements are forced onto the pipe by the wellhead pressure present.

Back Pressure Pump(BPP): This is an auxiliary pump installed on the rig. When the mud pumps at rig are being ramped down slowly for connection purposes the back pressure pump is turned on and ramped up when the mud pumps drop below a defined threshold.

This is to achieve cross flow via RCD and choke manifold and therefore build back pressure at surface. Alternatively, the back pressure pump may directly be attached to choke manifold on the rig. Figure- 3.4 illustrates the back pressure pump used for MPD operations.

BPP is usually turned on when making pipe connection to build a pressure in annulus that will compensate for the loss of annular friction pressure. Pressure will have to be trapped in annulus by adjusting the choke.

Figure-3.4: Back pressure pump[30]

Choke Manifold: Choke manifold is a unit made of a set of valves to perform pressure control while drilling. Choke manifold is also used to handle well control issues. Apart controlling fluid flow back from well to the mud pits, particular function of choke manifold in MPD is to control annular pressure and ECD. Choke manifold is opened to a certain level while drilling. When mud pumps are turned off and circulation is stopped for connection BPP and choke manifold are automatically engaged. I.e. the BPP is being ramped up while choke is being closed gradually to trap back pressure to maintain the bottom-hole pressure at the same level as in circulation phase.

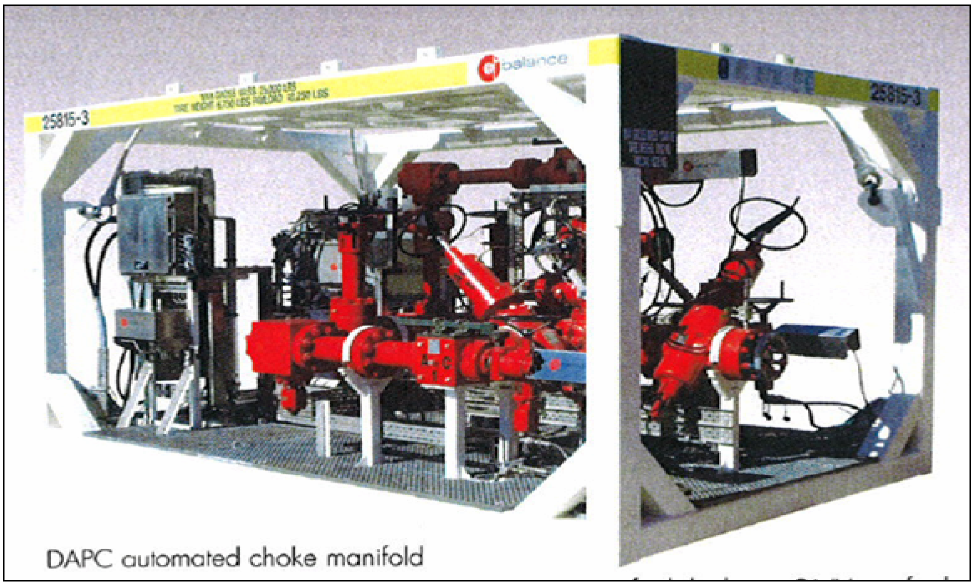


Figure-3.5: Choke manifold used for MPD[29]

Choke manifold can be operated by manual, semi-automatic or fully automatic means. Because of the need for eliminating wellbore pressure spikes full automatic choke is most preferred. The manually handled choke is not so efficient compared to automatic one. It is operated by a choke operator and the improper closing/opening of valves can result in pressure spikes in wellbore pressure. However, automatically operated choke system is very sensitive and more accurately controls pressures within wellbore. Figure-3.5 displays a dedicated choke manifold for the managed pressure drilling, which is operated automatically.

Non-Return Valve: Drill pipe Non-Return Valve (NRV) is essential to MPD operations. Looking at the U-tube principle so commonly discussed in well-control activities it is evident that any positive overbalance in the annulus forces drilling fluid back up the drill pipe. The drilling fluid may carry cuttings that can plug down-hole motor or measurement while drilling tool. In the worst case blow out through drill pipe may occur. To avoiding this NRV is used in drillpipe.

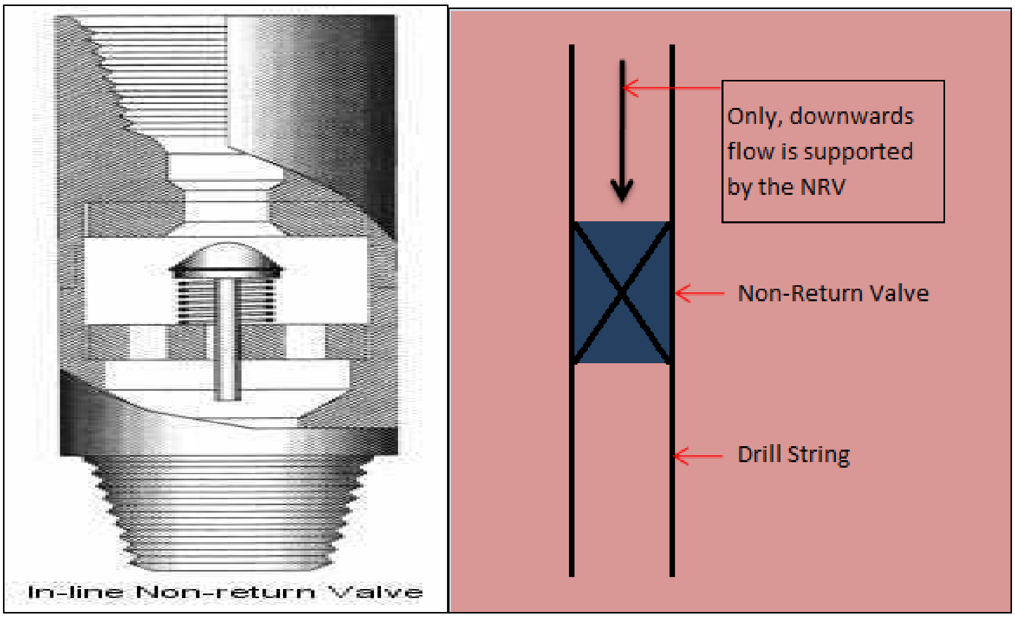


Figure-3.6: NRV and its illustration within drill string[43]

The non-return valve is a one-way valve. Figure-3.6 shows a NRV mounted in the drill string, to the left is a picture of NRV. The dart mounted on the spiral is pushed downwards when pressure inside the drill string is higher than the pressure in annulus and thus opening for downward flow. If the pressure in annulus becomes greater than in drillstring, the dart is pushed upward by the spiral into its dedicated groove preventing upward flow through drillstring.

Integrated Pressure Manager: While drilling a MPD well, measurement, monitoring, analysis and control are integrated into the Integrated Pressure Manager (IPM). IPM consists of a control computer, a programmable logic control system, a real-time hydraulics model and data communications network. Accurate BHP control requires a steady stream of accurate data. Regularly updated drilling parameters and real-time data from the pressure-while-drilling tool are transmitted to the IPM and thereby into the hydraulics model to adjust the surface and system pressures appropriately. The main function of PWD tool is to record real-time down-hole pressure data and transmit it to surface within a reasonable amount of time.

3.2.5 Back Pressure Operation

MPD rig-up is different from over balanced drilling in a way that it requires extra equipments to be added to the already existing conventional drilling equipment. Back pressure rig-up configuration is case and company specific. A number of vendors are available Halliburton, @ balance, Weatherford and etc. Nevertheless, equipment specifications and procedures for performing MPD may change from company to company back pressure pump, choke and RCD are needs for a back pressure technique of MPD in any case. RCD is located below the drill floor and over ROP. Annulus outlet is through the flow spool that is the lower most component of RCD. BPP can be attached to flow spool or directly to the choke depending on the vendor. Throughout drilling back pressure build-up and drawdown are performed by engaging the BPP and choke manifold. The automatic MPD system is preferred for use. StatoilHydro uses fully automatic system. An advanced hydraulics model built in the system calculates back pressure to apply and adjusts it for surge, swab, pump rate change, temperature effect, mud density change and rpm

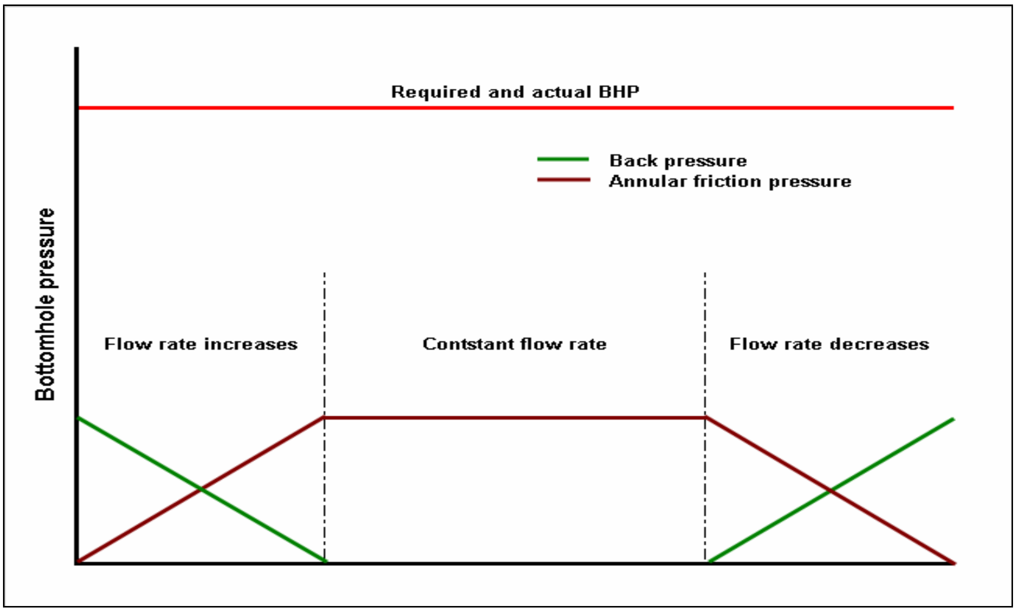


Figure-3.7: Constant operational BHP over flow rate change in MPD

BPP and choke work interactively. When mud pumps go off, back pressure pump is ramped up interactively with the flow rate decrease from mud pumps. Choke starts closing in such a way that AFP loss is smoothly compensated by trapped back pressure at surface. The opposite takes place when drilling resumes again. BPP is slowly ramped down with the flow rate increase from mud pumps. Choke in this case starts opening to a certain level allowing mud return to flow through the choke without trapping unnecessary pressure. As a consequent of such pressure management BHP is being maintained constant throughout drilling as shown in Figure-3.7. Figure shows the automatic pressure control in MPD with flow rate change.

3.3 Continuous Circulation System (CCS)

3.3.1 Introduction

CCS is dedicated for maintaining circulation during drilling. It eliminates the bottom-hole pressure changes during connections.

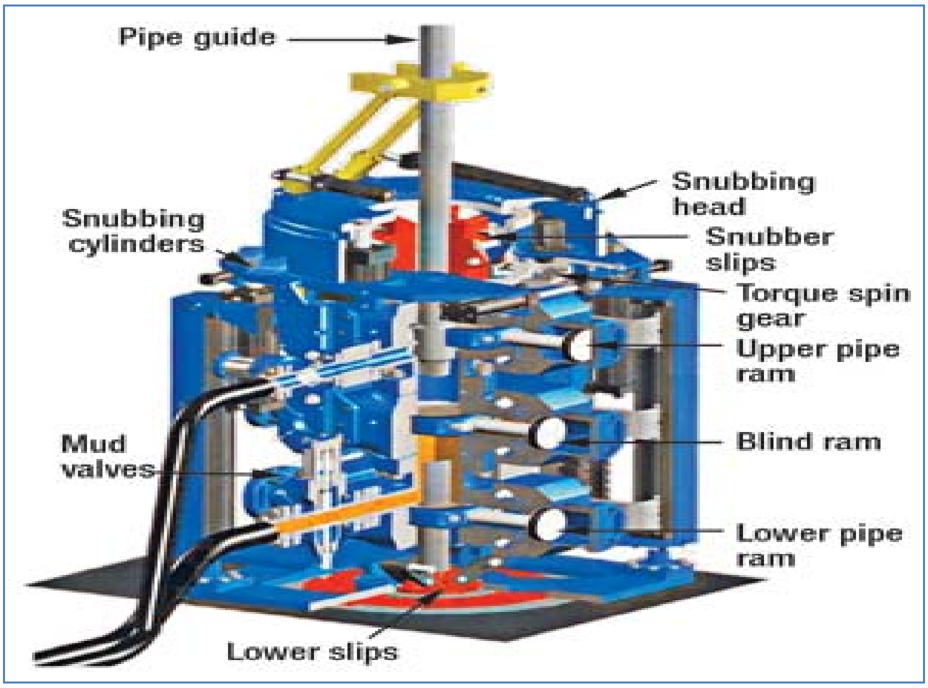


Figure-3.8: The main CCS unit[36]

This system has a potential to increase drilling efficiency in places where maintaining annular friction pressure is the key to achieving objectives set. With this system a steady equivalent circulating density (ECD) can be maintained.

CCS minimizes positive and negative pressure surges associated with making connection under normal drilling conditions. This enables a more stable well bore with improved hole-cleaning and removal of connection gas. Depending on the situation and professionalism of CCS crew may reduce connection time. The CCS has proved to be a safe and reliable system that allows operators to drill high pressure-high temperature and tight drilling window wells without drilling problems.

3.3.2 CCS System

CCS is a pressure chamber through which drill string passes. It can form a seal on each side of drill-pipe tool joint. Figure-3.8 illustrates the main unit of CCS. As seen from Figure-3.8, the unit has been built in a BOP style. This design allows pressure inside and outside drill string to be equalized by introducing drilling fluid at circulating pressure into the chamber between the seals. The pressure equalization and diverting mud between chambers is done by mud diverting manifold tied to high pressure delivery line between mud pumps and stand pipe. Mud diverting manifold is a part of the CCS system. Connection is broken and the pin is backed out and raised clear of the box before the pressure chamber is divided into two sections by a sealing device closing above the box. As observed from the picture, the seal function is obtained by the blind ram in between. Pressure is then bled off in upper section allowing the pin connection to be removed. At the same time, uninterrupted circulation is maintained along the side of chamber and down the open tool joint box.

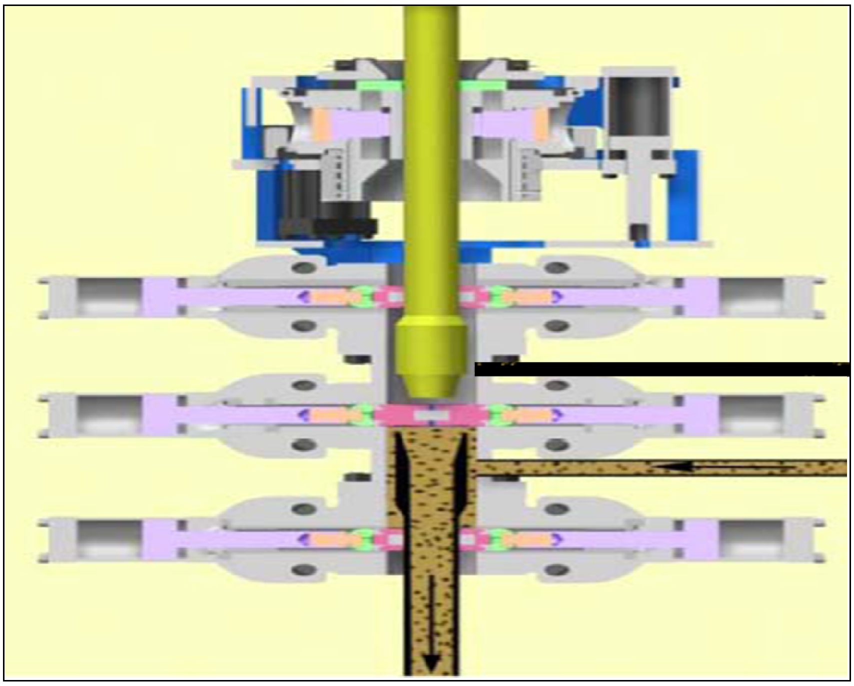


Figure-3.9: The cut away view of CCS[35 (p.227)]

To add a new joint or stand of drill pipe connected to the top drive it is run into the upper chamber which seals around pipe body and is filled with drilling fluid at circulating pressure. Having equalized pressures the dividing seal can be opened tool joint pin and box brought together and the connection made up with circulation redirected through the top drive into the drill string. When pressure in the chamber is bled off the seals are opened and drilling can resume. At the top of pressure chamber a combination power tong and snubbing device are attached to control pipe handling in the chamber.

Figure-3.9 displays cutaway view of the CCS. It shows how the connection is done and circulation is being kept while connection. Make up and breakout of connection and the movement of drill pipe into and out of the upper section are performed under circulating pressure conditions. After division of chamber into the upper and lower sections by blind ram, circulation is maintained through the flow line attached into the unit. The lower pipe ram must always be closed and so does the upper pipe ram. Fluid is pumped down the drill string that exits through bit and comes up the annulus. Mud return exits through outlet that is below the drill floor. CCS itself is located on the drill floor. Note that CCS unit can also be used together with the choke manifold and RCD.

3.3.3 CCS Control System

Control system is fully automatic enabling trained technical personnel to safely and efficiently operate CCS. The system has built-in safety alarms, manual interlocks between activities and ability to reverse or undo steps in operating procedures. Operating system is controlled from a touch screen. It is self-checking but it can be interrupted at any stage and activity can be reversed by the operator. Most important of all it is safe for all personnel involved. All pipe handling (by snubbing jack) and break-out/make-up (by CCS unit) are done without direct manual interference.

It is extremely important to train the personnel and ensure proper communication between the driller and CCS operator. The operations done in Kvitebjørn (StatoilHydro) shows that having the crew trained on how to make connections has become the most time consuming part of the training.

3.3.4 Application

CCS has been particularly effective when used to drill formations where making connections conventionally is difficult due to narrow drilling window. Balanced pressure drilling is unique among managed pressure drilling techniques. It maintains uninterrupted circulation during connections to establish constant BHP regime throughout drilling. This steady-state circulating condition eliminates the transitory down-hole pressure effects experienced during conventional drill-pipe connections. Using CCS can result in improved hole-conditions and may reduce connection time.

3.3.5 Pressure Management

CCS is a dedicated system aimed at maintaining constant ECD throughout operation. Unlike back pressure method CCS neither increases surface pressure nor decreases it. However, these two have a common target of sustaining constant bottom-hole pressure. Figure-3.10

illustrates the existing pressure difference between MPD back pressure and CCS techniques while pipe make-up or breakout

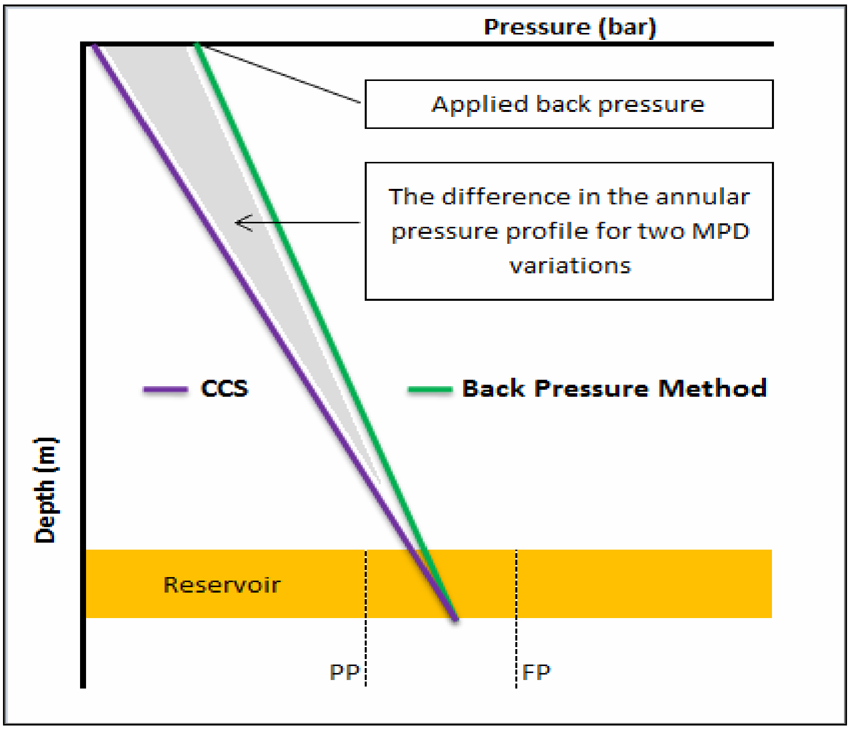


Figure-3.10: Pressure profile difference during pipe connection

In back pressure technique once circulation resumes annular pressure profile shown in green line will gradually shift towards left at the surface but stay constant at the bottom. However, in CCS annular pressure profile will remain unchanged as shown.

3.3.6 CCS Rig-Up

CCS unit is pretty massive and a heavy equipment. It is therefore landed on the drill floor. Flow lines, hoses and other related equipment are also handled on the drill floor. The system is operated by trained drill crew using automatic means. Manual interference of any member of drill crew is possible if necessary. Dedicated rules and procedures should be followed up if manual interference necessitates. Below the drill floor is rig-up of conventional drilling equipment and system.

CCS unit is very expensive and there is only one supplier (National Oil Varco) for the time being. CCS unit has the following dimensions

- Base : 5 x 6 ft (1.5 x 1.8 m)

- Height : 6 ft (1.8 m)
- Extended height : 12 ft (3.6 m)

System requires enough space and height in the rig. Lack of enough height for CCS may allow for drilling with singles or two pipe joints but not pipe stands. In such circumstances, more time may be spent for drilling and drilling procedures may need to be changed. Due to such reasons, CCS may not be applicable in all drilling rigs.

3.4 ECD Reduction Tool

Another cutting-edge MPD technology is Weatherford's ECD reduction tool shown in Figure-3.11. The tool developed in collaboration with BP is a turbine pump down-hole tool that produces a "pressure boost" to the return fluid in annulus. This results in dual gradient situation in annulus return. It is designed to counter down-hole pressure increases caused by friction in annulus by reducing equivalent mud weight.

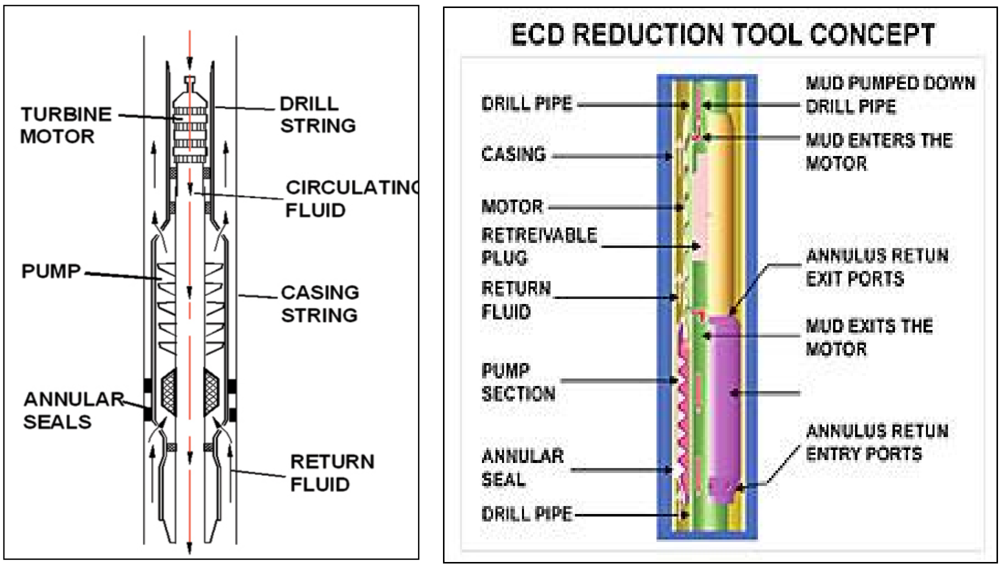


Figure-3.11: ECD reduction tool[37 & 38]

The ECD reduction tool consists of three sections. At the top is a turbine motor that draws hydraulic energy from circulating fluid and converts it into mechanical energy. The turbine drives a multi-stage pump in middle which adds energy to return fluid creating required pressure differential in annulus. Turbine is matched to the pump and both run at the same speed. The lower section of ECD reduction tool consists of annular seals to ensure that all return fluid and cuttings pass through the pump. The annular seals remain in constant contact with casing. They are supported on bearings so that the annular seals do not rotate with respect to casing when drillstring is rotated. Tool is expected to have a broad range of drilling applications including narrow pressure margins in deepwater environments, wellbores prone to instability, pressure depleted reservoirs and extended reach wells. It has not been used in StatoilHydro yet.

3.5 Pressurized Mud-Cap Drilling

This method of MPD uses two different drilling fluids to manage severe lost circulations. One of the drilling fluids is called sacrificial and lost to formation during drilling while the other is a heavy and viscous fluid that is pressurized in annulus and serves as an annular barrier. If drilling through reservoirs of interest will lead to loss of dedicated and expensive drilling fluid and is not possible get returns back. Mud cap drilling is used with the aim of drilling with full loss. Heavy-viscous mud is pumped down to some depth and placed in annulus. In a very simple form mud is pumped (bull-headed) in annulus until the well goes on vacuum. After this, drilling resumes by pumping sacrificial fluid down the drill string with no returns to surface.

The sacrificial fluid should be cheap and environmentally friendly. Usual fresh water is used for this purpose. Annular fluid is pressurized with a purpose of keeping well on state vacuum so that drill cuttings and sacrificial fluid will easily be lost into the formation.

3.6 Dual-Gradient Drilling

Dual gradient drilling is one of the MPD techniques that primarily relates to deepwater drilling applications. As the name implies two fluids having different densities are utilized. One is drilling fluid the other is riser fluid. Riser fluid is lighter than drilling fluid and in many cases seawater is used. The idea here is that drilling fluid doesn’t travel through the riser. Mud return is diverted to a subsea pump installed on the sea bed. Subsea pump delivers mud up to the rig and it is further pumped through a flow line to mud pits. Based on down-hole conditions, the level of riser fluid is arranged so that the bottom-hole pressure is kept and control at a desired level.

Application of dual gradient in the TTD may be relevant for subsea TTD but not for platform wells. In this study our purpose has been to look into MPD techniques that can be integrated with platform TTRD. For this reason, further details of dual gradient drilling will not be pursued here.

4 Drilling Hydraulics

4.1 Introduction

This Section addresses drilling hydraulics. Within the Section academic basis for further calculations, analysis and investigation is established. Pressure drop calculations, ECD concept, hole-cleaning issues and some of bit hydraulics are covered. Pressure loss calculations are based on a preferred model, regardless of the fact that details of all available rheological fluid models can be found. For practical purpose the equations will be provided in flied units.

4.2 Rheological Models

There exist several rheological fluid models used in fluid hydrodynamics. Some of them are utilized to characterize drilling fluids while some are not applicable to drilling fluids. During the study it was found out that there are about eight models such as

- Newtonian Model
- Bingham Plastic Model
- Power Law Model
- API Model (RP 13D)
- Herschel-Bulkley Model
- Unified Model
- Robertson-Stiff Model
- Casson Model

Each has its own application and depending on conditions and operational parameters all can be compared on one another. Drilling industry has used many of them, except Newtonian and Casson models the rest have been used to characterize drilling fluids. Details of all models above are given in Appendix-D.

It has been observed in this work that power law model more closely represents behaviour and characteristics of drilling fluid used in the field case chosen for this study. However, we refrain to state that power law model is the best to use for drilling fluid.

Since the power law model suited the field data that will be shown in Section-6, in the following we will address pressure loss calculations based on this model.

4.3 Friction Pressure Drop Calculations and Flow Regimes

Different equations and procedures have been proposed and used in the drilling industry for the aim of pressure loss calculations. Service companies providing software packages and this sort of services to the oil industry have dealt with this matter from various angles in their programmes and internal books. Unfortunately, there is not a straightforward solution and commonly recognized procedure and model for addressing pressure drop issue in drilling. Different companies and institutions have suggested different equations to calculate power law constants (*k* and *n*), apparent viscosity and eventually Reynolds number. In the following, a different procedure is recommended by use of the fundamental power law fluid model.

Power law constants to be used in the following are computed by

$$n = 3.32 \log\left(\frac{R_{600}}{R_{300}}\right) \tag{4.1a}$$

$$k = \frac{510 R_{300}}{511^n} \tag{4.1b}$$

4.3.1 Pipe Flow

Regardless of rheological model in use, velocity of fluid flowing through a pipe is given by

$$V_p = \frac{Q}{2.448 D_p^{\ 2}} \tag{4.2}$$

Fundamental Reynolds number for Newtonian fluids is given as

$$\mathrm{Re} = 928 \frac{D_p \, \rho_f \, V_p}{\mu_a} \tag{4.3}$$

To account for non-Newtonian character of drilling fluids, apparent viscosity for a power law fluid is presented as

$$\mu_a = \frac{k}{96}\left(\frac{D_p}{V_p}\right)^{1-n}\left(\frac{3+1/n}{0.0416}\right)^n \tag{4.4}$$

Substitution of apparent viscosity given by Eq. (4.4) into Eq. (4.3) yields to Reynolds number for power law fluid flow through a pipe that is expressed by

$$\mathrm{Re} = \frac{89100 \, \rho_f \, V_p^{\ 2-n}}{k}\left(\frac{0.0416 \, D_p}{3+1/n}\right)^n \tag{4.5}$$

For Newtonian fluids, say for water in which n is 1.0 and k becomes equal to viscosity of water then Eq. (4.5) easily reduces back to original Eq. (4.3). Based on Reynolds number to determine flow regime power law model sets following conditions [15]

Laminar: $\mathrm{Re} \le \mathrm{Re}_L = 3470\text{-}1370\, n$ (4.6a)

Transition: $3470\text{-}1370\, n < \mathrm{Re} < 4270\text{-}1370\, n$ (4.6b)

Turbulent: $\mathrm{Re} \ge \mathrm{Re}_T = 4270\text{-}1370\, n$ (4.6c)

Once the Reynolds number and flow regime are known, friction factor is calculated by[17]

Laminar: $$f = \frac{16}{\mathrm{Re}} \tag{4.7a}$$

Transition: $$f = \frac{16}{\mathrm{Re}_L} + \left[\frac{\mathrm{Re} - \mathrm{Re}_L}{800}\right]\left[\frac{a}{\mathrm{Re}_T{}^b} - \frac{16}{\mathrm{Re}_L}\right] \tag{4.7b}$$

Turbulent $$f = \frac{a}{\mathrm{Re}^b} \tag{4.7c}$$

Where a and b are given by[17]

$$a = \frac{\log n + 3.93}{50} \quad \text{and} \quad b = \frac{1.75 - \log n}{7} \tag{4.8}$$

Having friction factor computed for any flow regime one can easily calculate frictional pressure drop through a drillpipe using

$$\left(\frac{dp}{dL}\right)_p = \frac{f_p V_p{}^2 \rho_f}{25.81 D_p} \tag{4.9a}$$

$$\Delta p_p = \left(\frac{dp}{dL}\right)_p L \tag{4.9b}$$

In the following, an example is highlighted to show pipe friction factor behaviour.

Example-4.1

Assume drilling 8 ½'' hole with 5'' drillpipe. Drilling engineer becomes curious of calculating pipe friction factor. Necessary information is provided in Table-4.1

Drilling fluid data			Drillpipe data				Hole size (in)
Θ_{600}	Θ_{300}	Density (s.g.)	OD (in)	ID(in)	Grade	Weight (kg/m)	
90	60	1.600	5.000	4.000	E75	38.000	8.500

Table-4.1: Drilling fluid, drillpipe and wellbore data for example-4.1

Use of the above computational steps and given data, the following analytical result given in Figure-4.1 is attained by Matlab program.

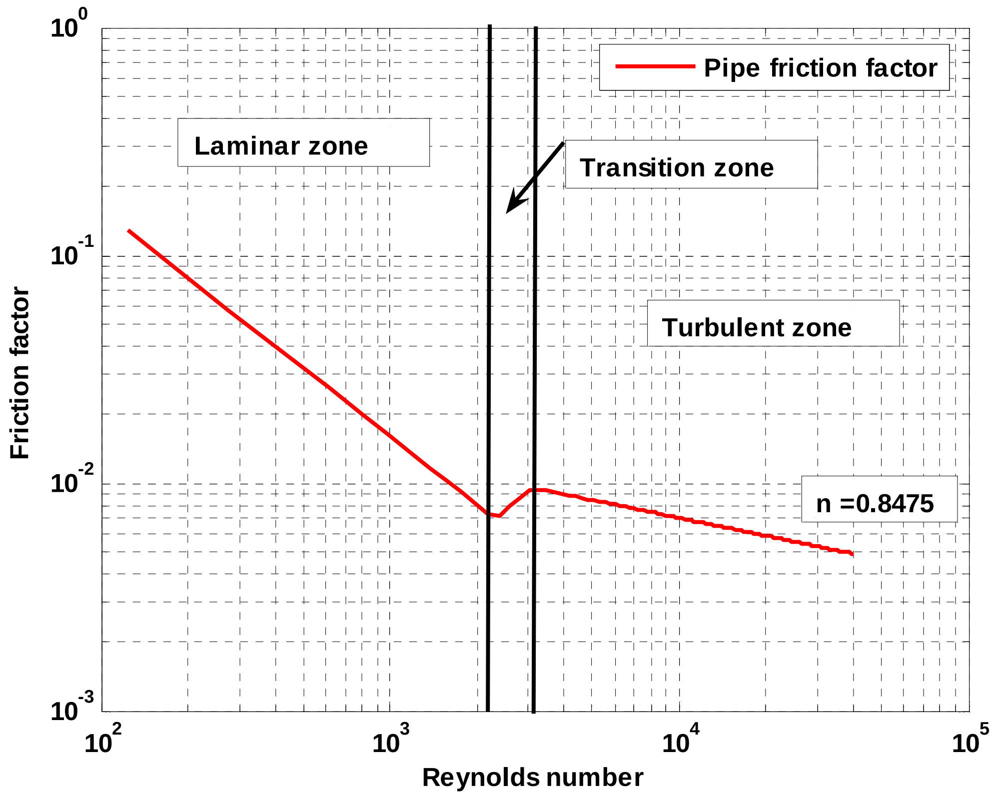


Figure-4.1: Pipe friction factor

4.3.2 Annular Flow

For flow through annulus, velocity of fluid known as annular velocity is calculated by simply writing Eq. (4.2) for annulus as

$$V_a = \frac{Q}{2.448\,(D_2^{\,2} - D_1^{\,2})} \tag{4.10}$$

To write Reynolds number for annulus flow, Reynolds number for pipe flow is extended to annular geometry by introducing hydraulic diameter concept. Four expressions are available to estimate hydraulic diameter that are given by[21]

$$D_h = D_2 - D_1 \tag{4.11a}$$

$$D_h = \sqrt{D_2^{\,2} + D_1^{\,2} - \frac{D_2^{\,2} - D_1^{\,2}}{\ln(D_2 / D_1)}} \tag{4.11b}$$

$$D_h = 0.816\,(D_2 - D_1) \tag{4.11c}$$

$$D_h = \frac{\sqrt[4]{D_2^{\,4} + D_1^{\,4} - \frac{(D_2^{\,2} - D_1^{\,2})^2}{\ln(D_2 / D_1)}} + \sqrt{D_2^{\,2} - D_1^{\,2}}}{2} \tag{4.11d}$$

All of the above have been used in practice to represent annular flow. Eq. (4.11a) and (4.11c) are perhaps most broadly used in petroleum industry. This is probably because of their simplicity rather than being superior precise. In recently appearing literature Eq. (4.11c) is used so intensively and will be used here as well. Replacing pipe diameter in Eq. (4.3) by hydraulic diameter given by Eq. (4.11c) Reynolds number for annular flow is arrived at

$$\mathrm{Re} = 757\,\frac{(D_2 - D_1)\,\rho_f\,V_a}{\mu_a} \tag{4.12}$$

Likewise, apparent viscosity of power law fluid flowing through annulus is expressed by

$$\mu_a = \frac{k}{144}\left(\frac{D_2 - D_1}{V_a}\right)^{1-n}\left(\frac{2 + 1/n}{0.0208}\right)^n \tag{4.13}$$

Substitution of Eq. (4.13) into Eq. (4.12) results in Reynolds number as

$$\mathrm{Re} = \frac{109000\,\rho_f\,V_a^{\,2-n}}{k}\left(\frac{0.0208\,(D_2 - D_1)}{2 + 1/n}\right)^n \tag{4.14}$$

Having Reynolds number calculated annular flow regime is defined based on

Laminar: $\mathrm{Re} \le \mathrm{Re}_L = 3470\text{-}1370\,n$ (4.15a)
Transition: $3470\text{-}1370\,n < \mathrm{Re} < 4270\text{-}1370\,n$ (4.15b)
Turbulent: $\mathrm{Re} \ge \mathrm{Re}_T = 4270\text{-}1370\,n$ (4.15c)

Annular friction factors are calculated as

Laminar: $$f = \frac{24}{\mathrm{Re}} \tag{4.16a}$$

Transition: $$f = \frac{24}{\mathrm{Re}_L} + \left[\frac{\mathrm{Re} - \mathrm{Re}_L}{800}\right]\left[\frac{a}{\mathrm{Re}_T^{\,b}} - \frac{24}{\mathrm{Re}_L}\right] \tag{4.16b}$$

Turbulent $$f = \frac{a}{\mathrm{Re}^b} \tag{4.16c}$$

Constants *a* and *b* are computed with the same expressions supplied by Eq. (4.8). Annular frictional pressure loss is calculated by

$$\left(\frac{dp}{dL}\right)_a = \frac{f_a V_a^{\,2} \rho_f}{21.1(D_2 - D_1)} \tag{4.17a}$$

$$\Delta p_a = \left(\frac{dp}{dL}\right)_a L \tag{4.17b}$$

During drilling frictional pressure loss in annulus is one of the most significant parameters to control and manage. Since any potential increase in annular pressure loss results in increase of bottom-hole pressure with the same value. To view how AFP loss changes in annulus as flow rate rises, the following example is given.

Example-4.2

Assume drilling of the same well given in Example-4.1 continues and the same data applies. Drilling engineer intends to find out annular pressure loss vs. flow rate to estimate achievable flow rate. Flow rate directly relates to annular velocity and thereby to hole-cleaning issues. Figure-4.2 illustrates analytical behaviour of pressure loss with pumping rate.

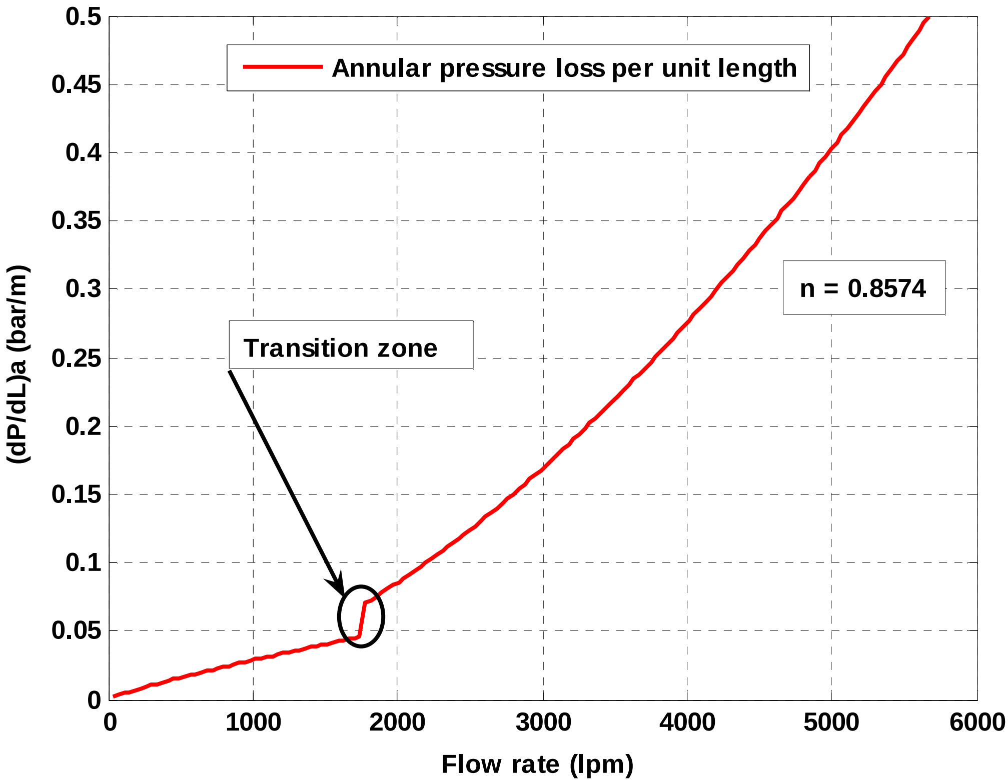


Figure-4.2: Annular pressure loss vs. pumping rate

4.4 Eccentricity, Rotation and Tool Joint Effects on AFP Loss

Accurate determination of pressure loss is important since it relates to bottom-hole pressure. For this purpose, taking all affecting factors into account helps to precisely define AFP. Eccentricity, pipe rotation and tool joint influence AFP. In the following, the most widely used methods will be highlighted to account for these effects.

4.4.1 Eccentricity Effect

Even vertically plan and drilled wells will have sections slightly deviated from vertical. Due to its weight drillstring is always expected to lie on the lower side of wellbore in inclined holes. In these situations annular becomes eccentric. Pressure drop in eccentric annulus will be different from that of concentric. Pressure drop in eccentric annulus can be as low as 40 % of that in concentric annulus. A widely used method[23] to estimate the magnitude of this reduction is based on product of concentric-annulus pressure loss and empirically derived ratio R depending on flow regimes (R is the ratio of AFP in concentric annulus to AFP in eccentric annulus). Equations to calculate R are given as

$$R_{lam} = 1 - 0.072\frac{e}{n}\left(\frac{D_1}{D_2}\right)^{0.8454} - \frac{3}{2}e^2\sqrt{n}\left(\frac{D_1}{D_2}\right)^{0.1852} + 0.96\,e^3\sqrt{n}\left(\frac{D_1}{D_2}\right)^{0.2527} \tag{4.18a}$$

$$R_{turb} = 1 - 0.048\frac{e}{n}\left(\frac{D_1}{D_2}\right)^{0.8454} - \frac{2}{3}e^2\sqrt{n}\left(\frac{D_1}{D_2}\right)^{0.1852} + 0.285\,e^3\sqrt{n}\left(\frac{D_1}{D_2}\right)^{0.2527} \tag{4.18b}$$

For transition zone, estimation of R is more complex. Linear evolution of R between R_{lam} and R_{max} can be assumed for Reynolds numbers falling in transition zone or Eq. (4.18b) can be used for transition zone as well. R in fact is a multiplication factor for Eq. (4.17a). For concentric annulus, R will become one while for eccentric annulus it will typically range between 0.6 and 1.

4.4.2 Rotation Effect

Annular pressure loss has been found to increase due to rotation. Here we will demonstrate a simplified method[24] to estimate rotation effect on pressure loss. The correlation is

$$\Delta P_R = 0.00001\,N\left(-1.0792\left(\frac{D_1}{D_2}\right) + 17.982\left(\frac{D_1}{D_2}\right)^2\right)L \tag{4.19}$$

As seen, method simply accounts for geometry factor and rotation speed. The drawback could be that fluid rheology effect is not included as parameter.

4.4.3 Tool Joint Effect

Tool joint is a necessary part to extend drillpipe. The gap between tool joint and casing/open-hole is narrower than between pipe body and casing/open-hole. Fluid flowing through annulus experiences a geometry change in tool joints. Pressure loss in tool joint body is calculated as in pipe body since only flow area change occurs and therefore annular velocity.

Calculation of pressure losses at the end sides of tool joint is rather complex. This is sometimes ignored due to fact that pressure loss in tool joint body is larger than at the tool joint end points. For this reason, pressure in tool joint can be calculated based on flow area change. Tool joints will increase pressure loss in annulus.

4.5 Equivalent Circulating Density (ECD)

Pressure imposed upon subsurface formation while drilling is equal to annular frictional pressure losses from the depth of interest to annular outlet plus hydrostatic pressure exerted by effective mud weight. Resultant bottom-hole pressure is expressed as an equivalent mud weight that will result in the same pressure. This equivalent mud weight is termed as equivalent circulating density and mathematically expressed as

$$ECD = \rho_e + \frac{P_{AF}}{0.052\ TVD} \tag{4.20}$$

Accurate calculation of ECD is required to know bottom-hole pressure and prevent drilling problems caused by excessive bottom pressures.

4.6 Hole-Cleaning

In the following, important elements of hole-cleaning that are relevant for this work will be looked into. Cuttings settling mechanisms and characteristics, flow patterns, mud properties and cuttings concentration will be focused on. Furthermore concentration will be on slip velocity.

4.6.1 Hole-Cleaning Introduction

Hole-cleaning is one of the basic functions of any drilling fluid. Cuttings generated by the bit, plus any cavings and /or sloughings must be carried by the drilling mud to the surface. Failure to achieve effective hole-cleaning can lead to serious problems.

These include stuck pipe, excessive torque and drag, annular pack-off, lost circulation, excessive viscosity, gel strength, high mud costs, poor casing and cement jobs. Cuttings transport is affected by several interrelated mud, cuttings and drilling parameters as shown in Table-4.2. Annular velocity, mud viscosity, wellbore inclination and string rotation are considered to be the most important ones. Primary methods used to improve hole-cleaning are to increase flow rate (annular velocity), mud viscosity and pipe rotation particularly when in laminar flow.

Well profile and geometry	• Hole angle and doglegs • Hole/tubular geometry • Drill string eccentricity
Cuttings and cuttings-bed characteristics	• Specific gravity • Particle size and shape • Reactivity with mud
Flow characteristics	• Annular velocity • Annular velocity profile • Flow regime
Mud properties	• Mud weight • Viscosity • Gel strength
Drilling parameters	• Bit type • Penetration rate • Differential pressure • Pipe rotation

Table-4.2: Parameters affecting hole cleaning[18 (p.618)]

Viscosity and annular velocity are most important and critical parameters. Cuttings and particles that must be removed from the well have three forces acting on them as shown in Figure-4.3a.

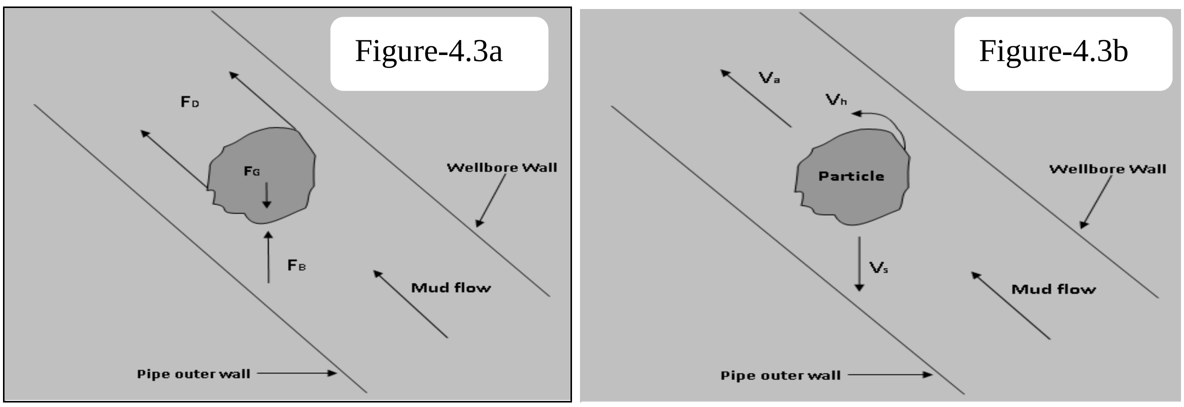


Figure-4.3: Velocity components and forces acting on a particle

The Shown are (1) a downward force due to gravity, (2) an upward force due to buoyancy from the mud, (3) a force parallel to the direction of mud flow due to viscous drag caused by mud flowing around the particle. These forces cause cuttings to be carried in the mud stream in a complex flow path that is often helical because of the combination of upward and circumferential flow. A simplified illustration of velocity components of a particle is displayed in Figure-4.3b. (1) a downward slip velocity due to gravitation force, (2) a helical velocity due to peripheral and axial flow profile and (3) an axial velocity driven by axial mud flow. Vertical hole-cleaning phenomenon is perhaps well understood and easy to visualize and optimize compared to tilted holes. Hole-cleaning is very complex in inclined holes.

4.6.2 Particle Settling Mechanisms

Hole-cleaning process must counteract gravitational down-falling of particles to minimize cuttings settling tendency during both static and dynamic periods. Three basic settling mechanisms have been reported and can apply in hole-cleaning. (1) free fall, (2) hindered settling and (3) Boycott settling. All three can exist in directional wells while first two can also relate to vertical wells.

Free settling: This occurs when a single particle falls through a fluid without interference of other particles or any obstacle. Falling velocity depends on density difference between fluid and particle, fluid rheology, particle size and shape and flow regime of fluid. In turbulent flow settling velocity is believed to depend on rheology while in laminar flow Stokes' law applies for free settling. The larger the difference between the cutting and the fluid densities, the faster the particles will settle. At the same time, bigger particles will settle faster than small particles.

Hindered settling: This mechanism is considered a more realistic settling mode, particularly in slim-hole drilling and where high cuttings concentrations are present. The idea behind this mechanism is that fluid displaced by a falling particle creates upward force on adjacent particles and thereby mitigate slip velocity of one another. During a continuous drilling process the annulus is full of cuttings. The likelihood for hindered settling to occur is high in these circumstances. Net result is still an overall downward movement. However, settling rate will be less (hindered) than single particle (free fall).

Boycott settling: This is an accelerated settling pattern that can occur in deviated holes and bears the name of the physician who first reported that solids in tilted tubes tend to settle 3 to 5 times faster than they can in vertical tubes. Boycott settling is a consequence of rapid settling to the adjacent and lower side of deviated holes. This process causes pressure imbalance that leads to the upward flow of lighter fluid on the upper side of wellbore and downward movement of particles to the lower side of hole. At low flow rates mud flows mainly along the high side of hole and enhances the Boycott effect. Pipe rotation and high flow rates are recommended that will disrupt the pattern and result in better hole-cleaning.

4.6.3 Drill Cuttings and Their Characteristics

Specific gravity, particle size and shape and reactivity with drilling fluid are some of the important drill-cutting and cuttings-bed characteristics. Specific gravity depends on formations drilled and ranges from about 2.0 to 2.8, somewhat denser than most drilling fluids.

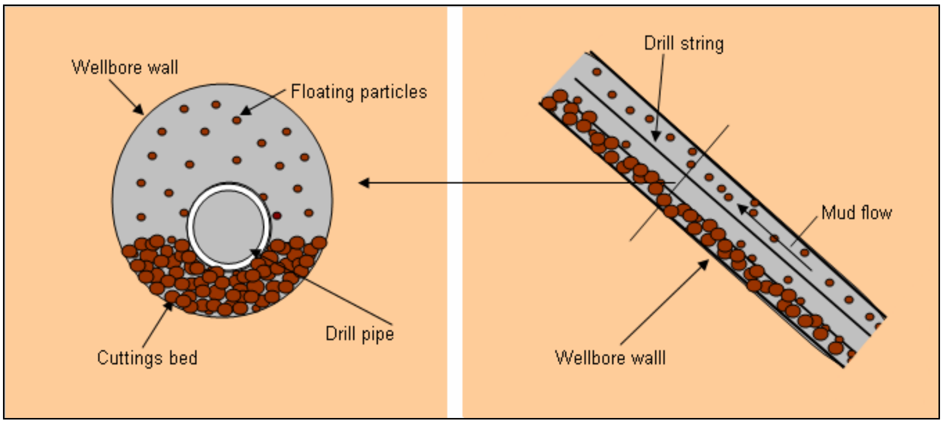


Figure-4.4: Cuttings bed in a highly tilted well

Bit type, penetration rate and bottom-hole differential pressure determine initial size and shape. Larger cuttings are generated by long-tooth bits, high penetration rates and lower differential (or underbalanced) pressures.

If not properly supported and removed cuttings can accumulate at the bottom of the well (fill). They also may accumulate in doglegs, washout zones (bridges) and on the low side of inclined intervals (beds). Figure-4.4 shows a cuttings bed formed on a highly deviated well. This kind of cuttings accumulations can be difficult to erode or re-suspend. Therefore mud properties and drilling practices that minimize cuttings bed formation should be emphasized. Cuttings remaining in flow stream do not become part of a bed of accumulation. Mud suspension properties are important, especially at low rates and under static conditions.

4.6.4 Flow Characteristics

Cuttings transport efficiency is strongly dependant on annular velocity and its profile. Increasing annular velocity will always improve hole-cleaning. In a concentric annulus flow is evenly distributed around drillstring as shown in Figure-4.5. There is an equal distribution of flow energy for cuttings transport regardless of fluid rheology. This profile is generally assumed while drilling vertical wells. However, wells are rarely vertical even planned and drilled as vertical. TTRD well typically has a deviated well path. In this case, drillstring tends to lie on the low side of hole and thereby disrupt annular velocity pattern as shown in Figure-4.6.

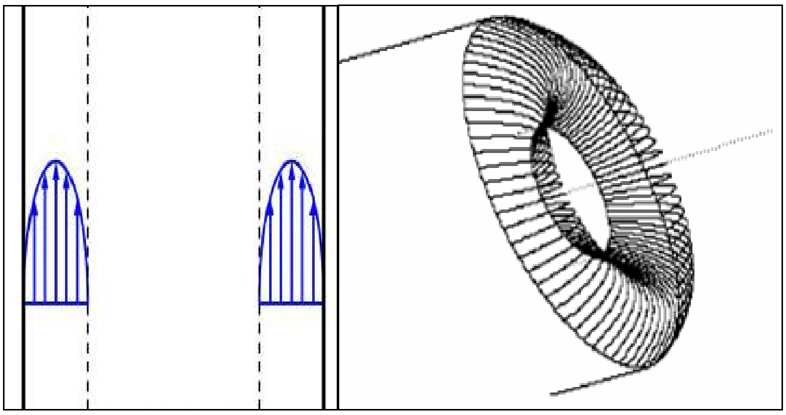


Figure-4.5: Concentric drill pipe and annular velocity distribution[39 & 40]

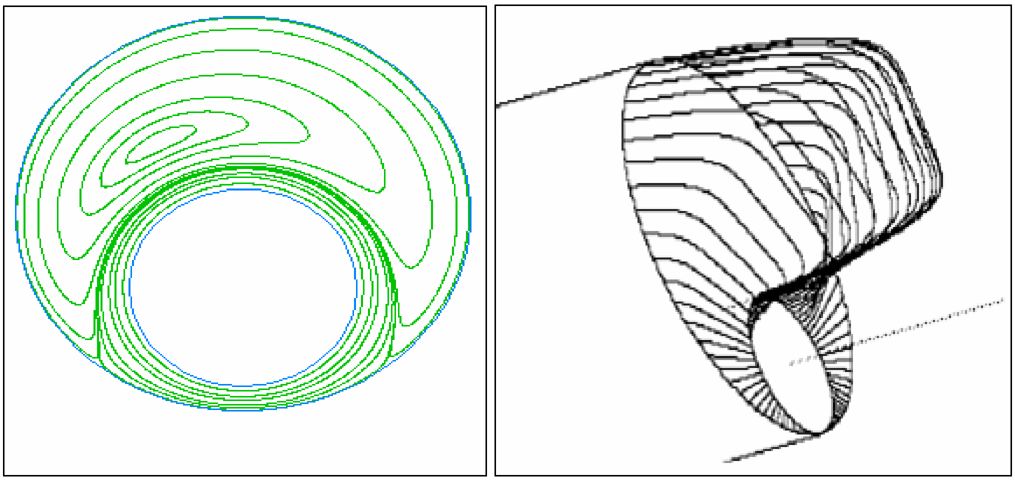


Figure-4.6: Eccentric drill pipe and annular velocity distribution[41 & 42]

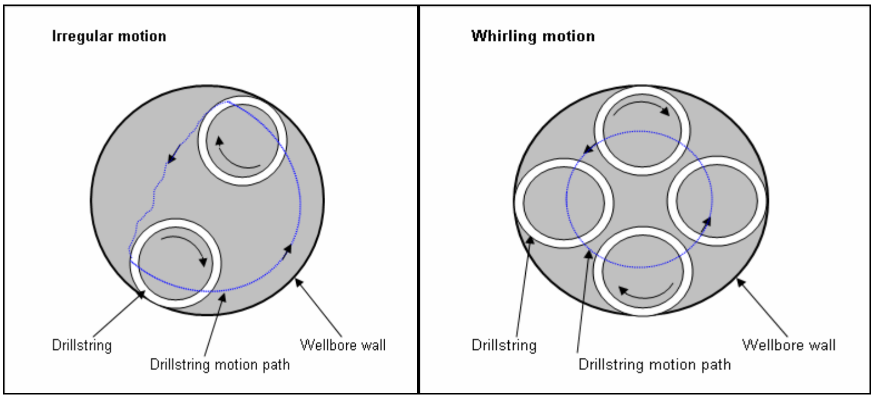


Figure-4.7: Drillstring motion within wellbore while rotating

Resultant velocity profile is not instrumental for cuttings transport. Cuttings accumulate on the low side of hole where annular velocity is minimal. In this situation, rotation of drillstring is critical for achieving efficient transportation of cuttings and effective hole-cleaning.

Drillstring rotation lifts cuttings from the low side of hole back into flow stream and promotes helical flow pattern. This sort of flow shape can be very effective for hole-cleaning even at low annular flow velocities. In high angle wells drillstring does not remain stable on the low side of hole while rotation. The string tends to climb the wall of wellbore and fall back as shown in Figure-4.7. This sort of motion even helps in hole-cleaning

Rotation may not be possible as in coiled tubing drilling and sliding mode of directional drilling. Turbulent flow is considered by some to be a prerequisite for good hole-cleaning in such applications.

4.6.5 Mud Properties

Three main categories of drilling fluids are (1) water-based muds, oil-based muds and gaseous drilling fluids in which a wide range of gases can be present. Primary functions of drilling fluids include

- Cool and lubricate bit and drillstring
- Clean the bottom of hole beneath the bit
- Transport cuttings to the surface
- Suspend drill cuttings in the annulus when circulation is stopped
- Support the wall of wellbore
- Control subsurface pressure
- Stabilize wellbore

Various drilling fluids provide similar cuttings transport if their down-hole properties are also similar. Selection of optimum properties requires careful consideration of all concerning parameters. Important parameters especially for hole-cleaning include mud weight, viscosity, gel strength and carrying capacity. In the following mud weight and viscosity are briefly touched

Mud Weight: Exceptional significance of drilling fluid mud weight for hole-cleaning is that it helps buoying drill cuttings and thereby slowing down their settling velocity (as dictated by Stokes' law). It is really not used to improve hole-cleaning. Instead, mud weight is to serve its primary function of exerting hydrostatic pressure and should be adjusted based on pore pressure, fracture gradient and wellbore stability requirements. Wellbore instability is a special case where the mud weight targets the cause rather than the symptoms of hole-cleaning problems.

Mud Viscosity: Viscosity plays particular role in hole-cleaning and aids defining the carrying capacity. As an old practice, rotational viscometer readings at 600 and 300 rpm are used to define the plastic viscosity and yield point of mud. Details of these equations can be in Bingham plastic model given at Appendix-D.

Viscosity of drilling fluid is affected by down-hole conditions especially in circumstances where high pressures and temperatures are present. Viscosity decreases as temperature rises.

4.6.6 Cuttings Concentration

Cuttings concentration is perhaps the best indicator for cuttings transport. Drilling problems start escalating when cuttings concentration exceeds a threshold value. General drilling practice is that cuttings concentration should not exceed 5 % to ensure good hole-cleaning. Cuttings concentration is calculated by

$$C_a = \frac{1{,}667\, ROP\, D_b^{\,2}}{60\,(D_b^{\,2} - D_p^{\,2})\,(V_a - V_s)} \tag{4.21}$$

During drilling effective mud weight differs from original mud weight. Change in hydrostatic head depends upon density of cutting, original mud weight and concentration of cuttings. Effective mud weight due to cuttings concentration can be given by

$$\rho_{e(c)} = \rho_p \frac{C_a}{100} + \rho_f \left(1 - \frac{C_a}{100}\right) \tag{4.22}$$

Practical parameter to control cuttings concentration is annular velocity. There is an annular critic velocity in annulus at which cuttings concentration reaches its threshold value. Annular critic velocity to maintain a specific cuttings concentration is obtained by solving Eq. (4.21) in terms of annular velocity. Equation to calculate numerical value of annular critic velocity is obtained as

$$V_{ac} = \frac{1{,}667\, ROP\, D_b^{\,2}}{60\,(D_b^{\,2} - D_p^{\,2})\, C_a} + V_s \tag{4.23}$$

Annular critic velocity is one of the most important parameters for hole-cleaning. Annular velocity should always be higher than the critic velocity. As seen from Eq. (4.23), slip velocity of participles is a part of equation. To calculate annular critic velocity slip velocity of cuttings should be computed too.

4.6.7 Cuttings Transport Ratio

The difference between annular velocity and slip velocity is known as the transport or rise velocity that is

$$V_r = V_a - V_s \tag{4.24}$$

Eq. (4.24) applies for vertical wells but not inclined holes. Best hole-cleaning is achieved when rise velocity approaches annular velocity. Poor hole-cleaning occurs if rise velocity is low. Cuttings Transport Ratio (CTR) is an applicable and a significant technique to normalize rise velocity. As a function of slip and annular velocities, the CTR is expressed as

$$CTR(\%) = \frac{(V_a - V_s)}{V_a} 100 \tag{4.25}$$

Hole-cleaning performance in different parts of wellbore can be directly compared by use of CTR. CTR ranges from 0 % (for very poor) to 100 % (for perfect) hole-cleaning. For vertical and near vertical wells, having CTR values greater than 50 % can be sufficient for hole-cleaning.

4.7 Slip Velocity

Several particle slip velocity correlations have been developed for predicting hole-cleaning performance of drilling fluids. Except the one developed by Walker and Mayes, the rest of these correlations are based on Stokes' law. In 1851, George Gabriel Stokes expressed slip velocity of an object (a particle) falling (creeping down) through a viscous fluid as

$$V_s = 138 \frac{d_p{}^2 (\rho_p - \rho_f)}{\mu} \tag{4.26}$$

Particle Reynolds number is determined by

$$\mathrm{Re}_p = 928.2 \frac{\rho_f \, d_p V_s}{\mu} \tag{4.27}$$

If flow pattern is different from free fall cutting-slip velocity determination can be based on empirical correlations. The known correlations are based upon dimensionless quantity known as the friction factor which is defined by

$$f = \frac{F}{A_c \, E_k} \tag{4.28}$$

Slip velocity correlations can be split into two groups, the first of which assumes drill cuttings to be spherical while the second assumes drill cuttings to have a shape of circular disk. Friction factors for spherical and circular disk shaped drill particles are given as

$$f_p = 3.57 \frac{d_p}{V_s^2} \left(\frac{\rho_p - \rho_f}{\rho_f} \right) \qquad \text{for spherical shape} \tag{4.29a}$$

$$f_p = 5.36 \frac{T_p}{V_s^2} \left(\frac{\rho_p - \rho_f}{\rho_f} \right) \qquad \text{for circular disk shape} \tag{4.29b}$$

Slip velocity correlations proposed utilize one of the above friction factors.

4.7.1 Moore Correlation

Preston Moore used Eq. (4.27) & (4.29a) for a spherical grain falling through a Newtonian fluid. To account for the non-Newtonian behaviour of drilling fluids, Moore suggested use of apparent viscosity concept. Apparent viscosity is attained by equating annular frictional pressure loss expressions for Newtonian and Power law fluid models. The apparent viscosity derived in this regard is expressed by

$$\mu_a = \frac{k}{144} \left(\frac{D_2 - D_2}{V_a} \right)^{(1-n)} \left(\frac{2 + 1/n}{0.0208} \right)^n \tag{4.30}$$

If particle Reynolds number is equal to or less than 1.0 flow regime is considered laminar and friction factor is approximated to be

$$f_p = \frac{40}{\mathrm{Re}_p} \tag{4.31}$$

Solving Eq. (4.27), (4.29a) & (4.31) together in terms of cutting-slip velocity leads to

$$V_s = 82.86 \frac{d_p^2 (\rho_p - \rho_f)}{\mu_a} \qquad (\mathrm{Re_p} \leq 1.0) \tag{4.32}$$

For transition flow regime friction factor was approximated by

$$f_p = \frac{22}{\sqrt{\mathrm{Re}_p}} \tag{4.33}$$

In transition flow regime where particle Reynolds number falls between 1.0 and 2000 particle's slip velocity can be calculated by

$$V_s = 2.90 \frac{d_p(\rho_p - \rho_f)^{0.667}}{\rho_f^{0.333}\mu_a^{0.333}} \qquad (1.0 < Re_p < 2000) \tag{4.34}$$

If particle Reynolds number is greater than 2000 friction remains essentially constant at a value of around 1.5. For this condition, flow pattern is considered to be fully turbulent and slip velocity of particle is given by

$$V_s = 1.54\sqrt{\frac{d_p(\rho_p - \rho_f)}{\rho_f}} \qquad (Re_p \geq 2000) \tag{4.35}$$

4.7.2 Chien Correlation

Chien correlation is similar to Moore correlation so that it also implies calculating apparent viscosity to determine the Reynolds number. Chien correlation utilizes Bingham plastic fluid model. For polymer-type drilling fluids, Chien suggested computing apparent viscosity by

$$\mu_a = \mu_p + 5\frac{\tau_y d_s}{V_a} \tag{4.36}$$

For bentonite mud systems, he recommended use of plastic viscosity instead of apparent viscosity. Slip velocity equation proposed by Chien is

$$V_s = 0.0075\left(\frac{\mu_a}{\rho_f d_p}\right)\left[\sqrt{\frac{36800 d_p}{\left(\frac{\mu_a}{\rho_f d_p}\right)^2}\left(\frac{\rho_p - \rho_f}{\rho_f}\right) + 1} - 1\right] \tag{4.37}$$

Use of this equation is recommended only when the viscous properties of drilling fluid are abnormally high, i.e. when $\mu_a/\rho_f d_p > 10$.
Chien also proposed much simpler equation to calculate slip velocity of cuttings in normal drilling fluids used in practical applications which is expressed as

$$V_s = 1.44\sqrt{\frac{d_p(\rho_p - \rho_f)}{\rho_f}} \tag{4.38}$$

This equation is the same with Eq. (4.35) except the numerical factor involved. This corresponds to using friction factor of 1.72 in Moore correlation for turbulent flow regime.

4.7.3 Walker and Mayes Correlation

Slip velocity correlation proposed by Walker and Mayes assumes drilling cuttings to have shape of circular disk and fall through drilling fluid on flat face horizontal. Particles are believed to have two settling regimes, laminar and turbulent. Shear rate called as boundary shear rate at which a particles' movement switches from laminar to turbulent is calculated by

$$\gamma_b = \frac{186}{d_p \sqrt{\rho_f}} \tag{4.39}$$

The shear stress developed by particles while fall through drilling fluid is expressed as

$$\tau_p = 7.9\sqrt{T_p(\rho_p - \rho_f)} \tag{4.40}$$

Once the shear stress created by particles is established, the corresponding shear rate can be calculated by using annular power law constants as

$$\gamma_p = \left(\frac{\tau_p}{k_a}\right)^{1/n_a} \tag{4.41}$$

Annular power law constants are calculated as in API rheological model (RP 13D).
If $\gamma_p < \gamma_b$, where slip velocity of a particle is in the laminar zone and is determined by

$$V_s = 0.02\tau_p\left(\frac{\gamma_p d_p}{\sqrt{\rho_f}}\right)^{0.5} \tag{4.42}$$

If $\gamma_p > \gamma_b$, where slip velocity of a particle is in the turbulent zone and is given by

$$V_s = 0.28\frac{\tau_p}{\sqrt{\rho_f}} \tag{4.43}$$

Based on the Reynolds number when it is greater than 100, Eq. (4.43) is used to calculate slip velocity of a particle. Otherwise, slip velocity is computed by Eq. (4.42) if Reynolds number is less than 100.

4.8 Bit Hydraulics

In the following, relevant bit hydraulics for the work will be briefly highlighted. Focus will be on bit pressure loss, nozzle velocity and hydraulic impact force. The equations to be given in the following will be used in Section-6 for purpose of calculation.

4.8.1 Bit Pressure Drop

Objective of any hydraulics programme is to optimize pressure drop across the bit such that maximum cleaning of bottom-hole is achieved. Pressure drop across the bit is greatly influenced by size of bit nozzles. The smaller the bit nozzles the higher the pressure drops through it. Pressure drop across drill bit is computed with

$$\Delta P_b = \frac{156.5\,\rho_f\,Q^2}{(D_{n1}{}^2 + D_{n2}{}^2 + D_{n3}{}^2 + ...)^2} \tag{4.44}$$

If coring or diamond bits are used the above equation is modified by introducing the total flow area (TFA) and fitting conversion factor. Pressure drop equation for diamond and coring bits is

$$\Delta P_b = \frac{\rho_f\,Q^2}{10858\,(TFA)^2} \tag{4.45}$$

Percentage of pressure loss occurring across the bit is simple expressed by

$$\Delta P_b(\%) = \frac{\Delta P_b}{\Delta P_t}100 \tag{4.46}$$

In addition to bit pressure loss, several other hydraulics calculations are done to optimize drilling performance. These include hydraulic horsepower, impact force and nozzle velocity computations. In the following, only hydraulic impact force and nozzle velocity are defined.

4.8.2 Nozzle Velocity

Despite the fact that more than one nozzle can be in the bit, nozzle velocity will be the same for all nozzles unless sizes are different. Nozzle velocity ranges between 76 to 137 m/sec for most drilling operations. Nozzle velocities higher than 137 m/sec may be aggressive for bit cutting structure. Flow velocity through nozzles of the bit is known as nozzle velocity and computed as

$$V_n = \frac{417.2\,Q}{D_{n1}^{\;2} + D_{n2}^{\;2} + D_{n3}^{\;2} + ...} \tag{4.47}$$

Or it can be simply expressed as flow rate divided by TFA of the bit.

4.8.3 Hydraulic Impact Force (HIF)

Per unit time momentum rate change of fluid flowing through the bit nozzles expresses hydraulic impact force. Hydraulic impact is a force generated by fluid exiting nozzles. The equation for calculating impact force is easily derived from Isaac Newton's second law. His second law tells that velocity change per unit time multiplied by mass results in force. If mass replaced by density multiplied by volume then we end up with hydraulic impact force as

$$HIF = \frac{Q\,\rho_f\,V_n}{1930} \tag{4.48}$$

If expressed per square inch of bit area impact force is written as

$$(HIF / in^2) = \frac{1.27\,HIF}{D_b^{\;2}} \tag{4.49}$$

5 Reservoir Depletion and Drilling Window

Over time the pore pressure of reservoir decreases because of the production. This reduction of reservoir pressure is known as reservoir depletion and causes change of down-hole pressure and stress environment. From drilling perspective, reservoir maturation leads to tighter ''Drilling Window''. In mature fields drilling has been challenged by tightness of available margins. Reservoir depletion resulting in narrow drilling window is not well understood and misinterpreted at times. In the following, thorough explanation of this process is given from drilling and rock mechanics perspective.

5.1 Drilling Window

Drilling Window is known as a pressure margin between fracture and pore pressures as shown in Figure-5.1. As a drilling practice wellbore pressure should always be greater than pore pressure both in static and dynamic conditions. Like, wellbore pressure shall not surpass fracture gradient otherwise costly drilling problems such as loss circulation and formation breakdown will occur.

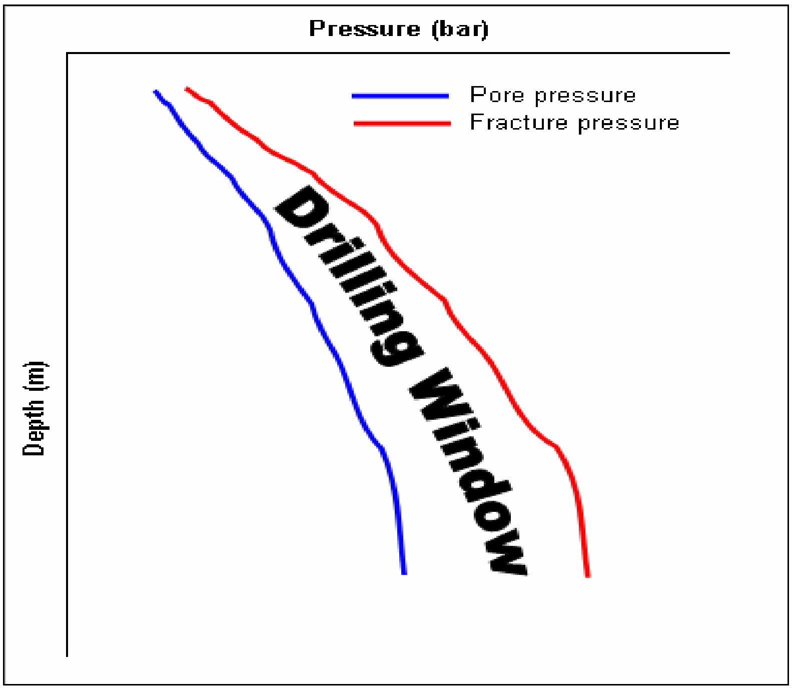


Figure-5.2: Drilling window illustration

During drilling, ECD varies and curve of which moves back and forth between pore and fracture pressures. To drill a well as safely and efficiently as required a certain margin is a need. In virgin fields and reservoirs there exist enough margins for drilling unless abnormal and subnormal pressures are encountered. Reservoir maturation results narrower drilling window that will challenge drilling. The tighter the drilling window the tougher the drilling will be.

5.2 Rock Mechanics Aspect of Drilling Window

Some may interpret the situation as if while production, fracture pressure reduces faster than pore pressure so that the result is narrow drilling window. The opposite is true i.e., during production fracture gradient reduces slower than pore pressure. The result will be enlarged drilling window.

To prove this and clarify the situation we look into the matter from a scientific and practical aspect. A reservoir in production compacts over time since pressure within pores decreases. For an isotropic material deformation along one axis will also result in deformation along other axes. Generalizing Hooke’s law into three dimensions the following equations are obtained.

$$\varepsilon_x = \frac{1}{E}\left[\sigma_x - \nu(\sigma_y + \sigma_z)\right] \tag{5.1a}$$

$$\varepsilon_y = \frac{1}{E}\left[\sigma_y - \nu(\sigma_x + \sigma_z)\right] \tag{5.1b}$$

$$\varepsilon_z = \frac{1}{E}\left[\sigma_z - \nu(\sigma_x + \sigma_y)\right] \tag{5.1c}$$

These expressions can be used for any material that behaves linearly elastic and represents strains induced along *X*, *Y* and *Z* axes. For a formation the set of Eq. (5.1a, b, and c) can be written as

$$\varepsilon_h = \frac{1}{E}\left[\sigma_h - \nu(\sigma_H + \sigma_o)\right] \tag{5.2a}$$

$$\varepsilon_H = \frac{1}{E}\left[\sigma_H - \nu(\sigma_h + \sigma_o)\right] \tag{5.2b}$$

$$\varepsilon_o = \frac{1}{E}\left[\sigma_0 - \nu(\sigma_h + \sigma_H)\right] \tag{5.2c}$$

For a subsurface reservoir lateral strains are assumed to be equal and zero. For this reason, equal horizontal stresses can be assumed. Solving Eq. (5.2a) and (5.2b) together horizontal stress is obtained as

$$\sigma_h = \frac{\nu}{1-\nu}\sigma_o \tag{5.3a}$$

Eq. (5.3) is usually written as

$$\Delta\sigma_h = \frac{\nu}{1-\nu}\Delta\sigma_o \tag{5.3b}$$

For the purpose of calculation Eq. (5.3b) is used to estimate change in horizontal stress due to change in overburden stress. In the following, Eq. (5.3a) will be used.

Vertical strain is different from zero since there exists a compaction and taking into account that horizontal stresses are equal from Eq. (5.2c) and (5.3a) the following is obtained.

$$\varepsilon_o = \frac{\sigma_o}{E}\left(\frac{1-\nu-2\nu^2}{1-\nu}\right) \tag{5.4}$$

Reservoir compaction during production can be calculated by Eq. (5.4). Stresses introduced so far are total stresses. Effective stresses are given as (index *e* stands for effective)

$$\sigma_{h(e)} = \sigma_h - p_o \tag{5.5a}$$

$$\sigma_{o(e)} = \sigma_o - p_o \tag{5.5b}$$

Effective horizontal stress can also be written as

$$\sigma_{h(e)} = \frac{\nu}{1-\nu}\sigma_{o(e)} \tag{5.6}$$

Substituting Eq. (5.5a) and (5.5b) in Eq. (5.6) the following expression is obtained.

$$\sigma_h - p_o = \frac{\nu}{1-\nu}(\sigma_o - p_o) \tag{5.7}$$

Fracture propagation of reservoir takes place in direction of maximum horizontal stress so that its magnitude is equal to minimum horizontal stress. Since equal horizontal stresses were assumed, Eq. (5.7) can be expressed as

$$p_f - p_o = \frac{\nu}{1-\nu}(\sigma_o - p_o) \tag{5.8}$$

The right hand side of Eq. (5.8) expresses drilling window then Eq. (5.8) may be written as

$$Drilling\ window = \frac{\nu}{1-\nu}(\sigma_o - p_o) \tag{5.9}$$

Eq. (5.9) shows that pore pressure decrease in producing reservoir leads to enlargement of available drilling window within reservoir. The reason is that fracture gradient reduction occurs slower than pore pressure decline.

Compaction model given by Aadnøy[26] also shows that reservoir depletion results in larger drilling window rather than smaller. Equation proposed by him to calculate fracture pressure change based on the Poisson's ratio and pore pressure change is

$$\Delta p_f = \Delta p_o \frac{1-3\nu}{1-\nu} \tag{5.10}$$

As Eq. (5.10) supports, drilling window within reservoir in production enlarges. The question how drilling window becomes narrow as a result of reservoir depletion is clarified in the following.

5.3 Process of Drilling Window Contraction

During drilling all the overlying reservoirs regardless of their productivity and non-productivity are penetrated through to reach the target reservoir. After being completed, well is put on production through the commercial reservoir while other non-commercial formations are isolated from wellbore. Before any production begins there exists certain distribution of pore and fracture pressures.

After production commences pore pressure of producing reservoir starts declining over time and so does fracture pressure. Overlying and underlying formations stay undrawn and virgin thus no pore pressure and fracture pressure change occurs in these formations.

Fracture pressure profile of reservoir being produced moves against pore pressure curve of formations being undrawn as shown in Figure-4.1. It demonstrates down-hole pressure distribution in well 34/11-A-13 of Kvitebjørn field (North Sea, Norwegian continental shelf) after being in production for a while.

As seen, fracture pressure profile within the drained reservoirs has moved towards the pore pressure curve of the undrawn formations. As a result, the available drilling widow has substantially narrowed. This is what happens when the productive reservoirs are exploited and depleted over time.

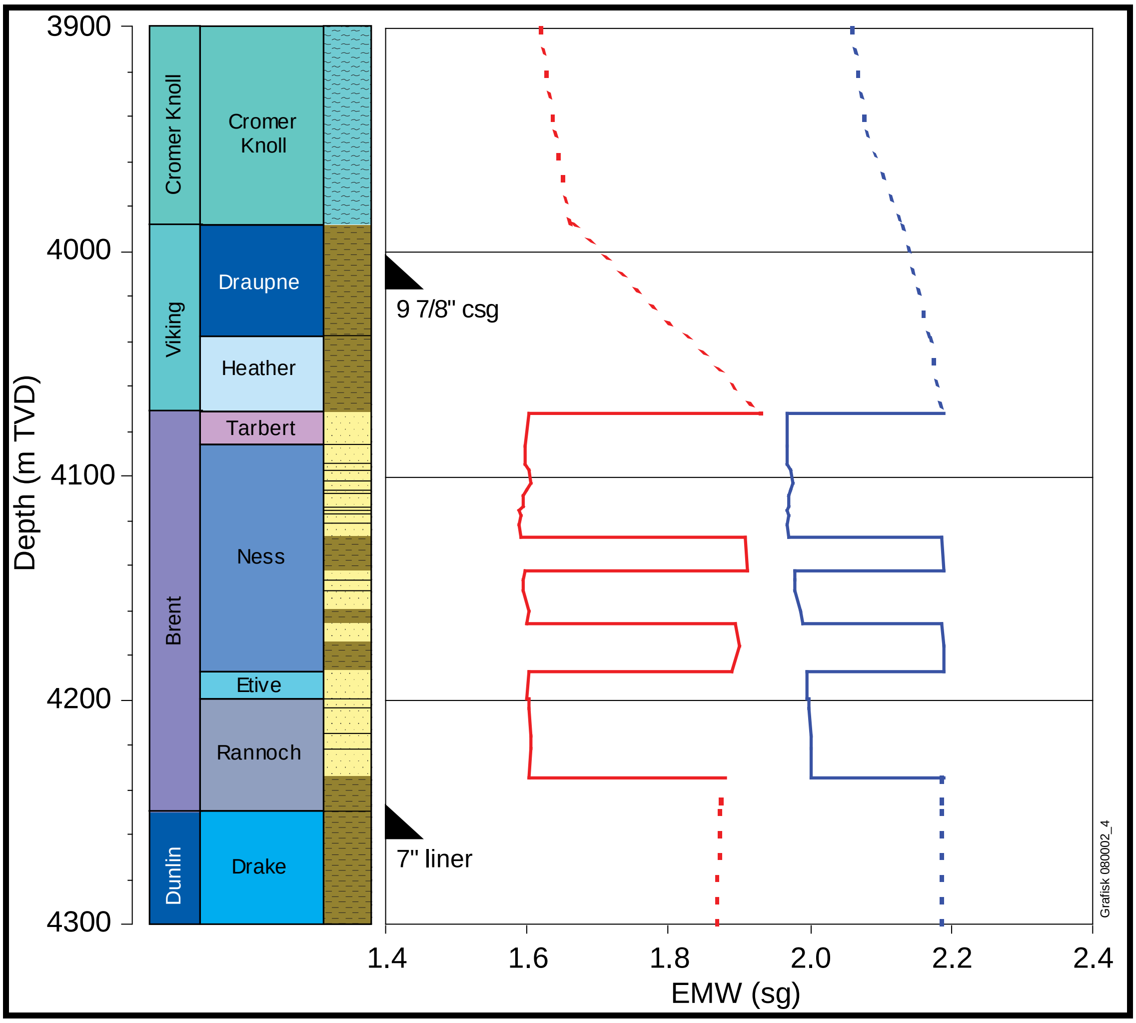


Figure-4.1: Down-hole pressure distribution in Kvitebjørn well: 34/11-A-13 after being on production for a while[45]

6 Hydraulic Issues of Conducting Through Tubing Rotary Managed Pressure Drilling

6.1 About This Section

StatoilHydro has a valuable experience with TTRD in its mature assets in the North Sea. TTRD campaigns have experienced several drilling problems. One of the problems seen in TTRD has been with ECD and its management. ECD control is challenged by narrow annular clearance present in TTRD. For example, TTRD well 34/10-B-4B drilled on Gullfaks field experienced severe loss circulations caused by tight drilling window and therefore didn’t reach its drilling target. In the following, possible application of MPD in TTRD wells will be discussed from drilling hydraulics standpoint. Focus will be on the ability of MPD for reducing mud weight and its effects on drilling parameters.

For this purpose, well 34/10-B-4B has been chosen as a field case to describe problem and highlight solutions. The following investigation and analysis will use field data of this well.

6.2 Problem Description

The TTRD well 34/10-B-4B was planned and drilled at Gullfaks field on the date of 09.05.2007 - 21.05.2007. Well was kicked off from 7’’ liner of the mother wellbore 34/10-B-4A at 2578 m MD / 1780 m TVD RKB. The plan was to drill 5 7/8’’ hole to the 3268 m MD / 1960 m TVD as shown in Figure-6.1.

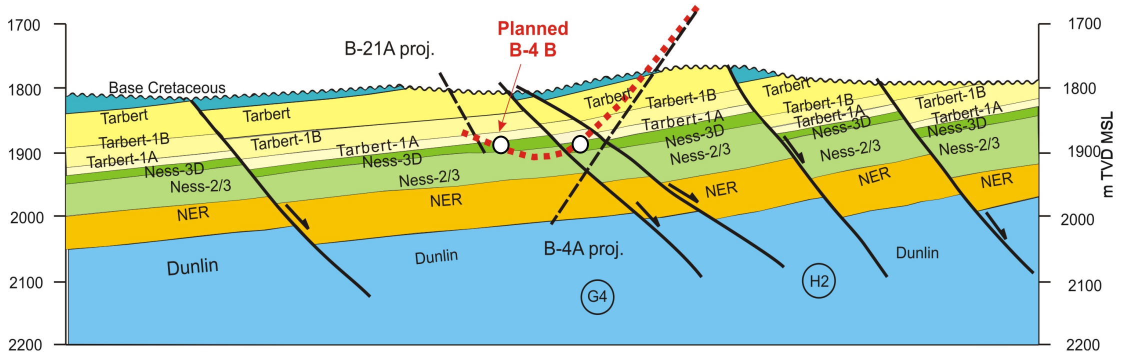


Figure-6.1: Planned wellpath (dashed red line) and expected stratigraphy before drilling. Targets have been marked with white circles[44]

The primary objective of B-4 B was to prove and produce oil in Ness-3D formation in the segment G4 on Gullfaks field. The secondary objective was to prove and produce oil in Tarbert-1A formation in the segment H2 and Tarbert-1A and Ness-3D formations in the G4 segment. Drilling was performed using Warp oil based mud with a mud weight of 1.68 s.g.

Unfortunately, from 2680 m MD down to 2920 m MD loss circulation incidents challenged drilling and at the depth of 2920 m loss rate intensified.

In Table-6.1 is the quotation from well report that tells about the lost circulation incident experienced in well B-4B

Wellbore ID	Interval	Rig name	Start time	End time	Duration (hours)	Depth MD (m)	Description
NO 34/10-B-4B	5 7/8'' TTDRIL	Gullfaks B	15.05.2007 (02:00)	15.05.2007 (05:30)	3.5	2920	Drilled/oriented 5 7/8" hole from 2918 m to 2920 m with 658 l/min, 243-247 bar, 1-5 ton WOB, ECD 1.760-1.765. Still having problems getting weight down to bit. Manage to drill 0.1-0.2 m each time we picked off bottom and slide back to bottom. Average loss during this report 0.4 M3/hr and total loss 10 M3.

Table-6.1: Quotation from DBR (StatoilHydro's internal drilling data base)

Any attempt to re-establish drilling parameter at this depth was unsuccessful due to increased losses with increased flow rate. For instance, when pumping rate was raised up to 155 lpm 83 % loss was experienced and thereafter it was decided to set TD at 2920 m MD as shown in Figure-6.2.

Reducing mud weight was not an alternative option since mud weight was higher than pore pressure just by 0.02 s.g. and because of the factor that gas content was observed in mud return.

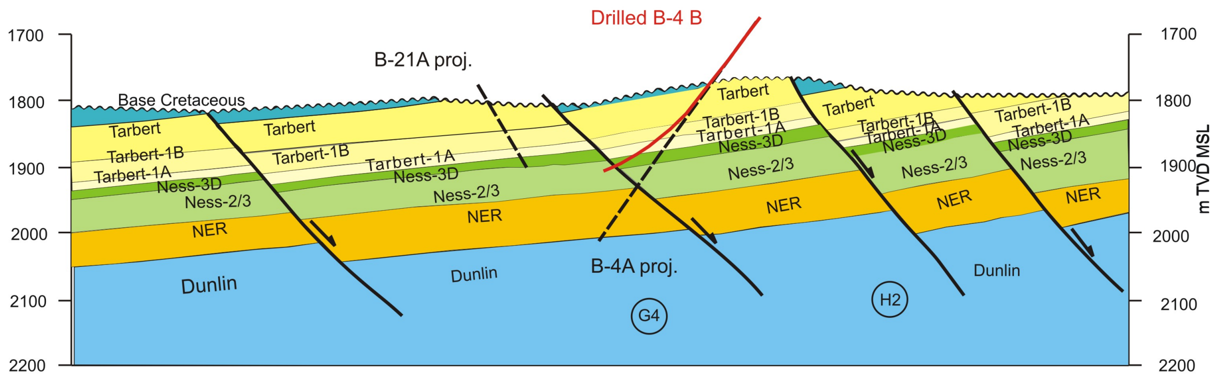


Figure-6.2: Actual wellpath (red line) of well 34/10-B-4B on Gullfaks[44]

The reason for loss circulation was that ECD had exceeded minimum fracture gradient between 2780 m MD and 2920 m MD. This was noticed neither during planning phase nor drilling because of overestimated (prognosed) fracture gradient. Post drilling re-evaluation showed that actual values of fracture gradient were less than the prognosis. Actual available drilling window was much narrower than the prognosed as shown in Figure-6.3.

As seen from the plot actual pressure margin has been 0.08 s.g. for drilling from 2680 m MD / 1977 m TVD down to TD. ECD management within this tight margin goes beyond the ability of conventional drilling. In particular, in long wells drilling conventionally inside this narrow operational envelope gives many drilling problems.

In Figure-6.4, ECD values calculated by different rheological models are given with the presence of actual field data. Observation is that ECD had exceeded minimum fracture pressure gradient below the depth of 1977 m TVD since both calculated and actual ECD values shows this. The other observation from Figure-6.4 is that field data points of ECD are more closely matched with result obtained by power law rheological fluid model. However, Robertson Stiff model that is a three-parameter model as of Herschel-Bulkley model also shows a satisfactory match with field data.

Note that actual ECD values experienced during drilling have been reported in the daily drilling reports that can be found in DBR, StatoilHydro's internal drilling data-base.

In conventional drilling it is a must to statically overbalance well throughout drilling. It is never acceptable to be balanced or underbalanced. However, successful drilling of the well in question could have been achieved by employing MPD.

The problems faced during drilling this well directly concerns drilling hydraulics, pressure and ECD management. These sorts of challenges can be eliminated by applying MPD since the strength of MPD is to address problems relating to pressure management.

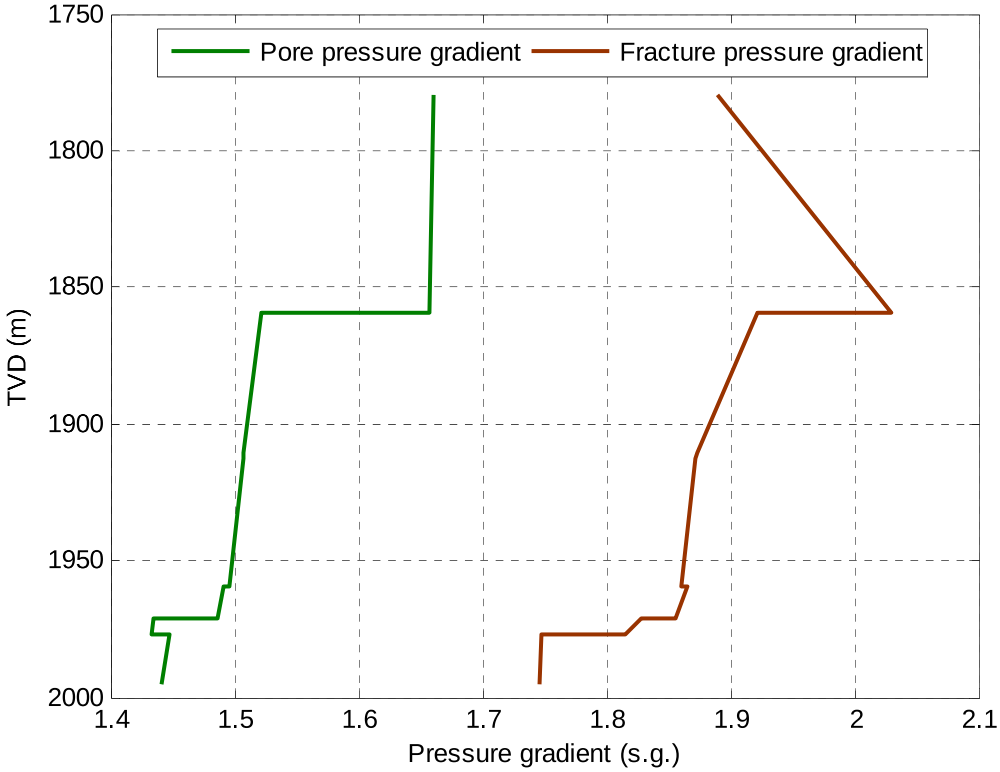


Figure-6.3: Actual pore and fracture pressure gradient distributions for OH section of well: 34/10-B-4B

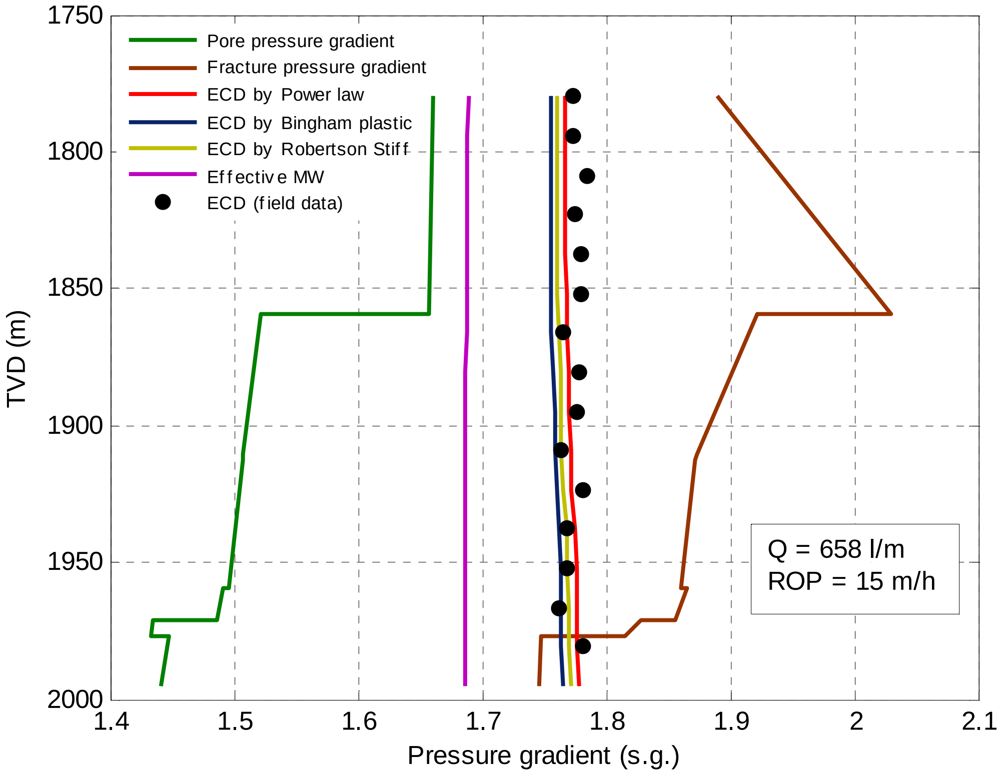


Figure-6.4: Calculated and actual ECD for OH section (well: 34/10-B-4B)

Note: All data (drillstring, wellbore geometry, survey and etc.) concerning the well: 34/10-B-B4 can be found in Appendix B.

6.3 Application of MPD from Hydraulics Point of View

TTRD is applied in fields being in decline (and/or plateau) period of their production phases. As reservoirs mature down-hole pressure environments become tough, leaving small margins for drilling. In StatoilHydro TTRD wells have been drilled conventionally.

Bringing in an example in the foregoing part it was shown that there are circumstances where TTRD may not be applicable due to tight drilling windows. Inability of conventional drilling to deal with drilling problems in such circumstances can make TTRD less economic. In some cases stopping drilling before reaching target as in well 34/10-B-4B can not be avoidable.

Alternative solution is MPD that can be applied to solve drilling problems in mature fields and allow StatoilHydro to maximise recovery in its assets by integrating TTRD and MPD. Two techniques of MPD may be coupled with TTRD on platform wells. These are back pressure technique and continuous circulation system. Dual gradient drilling can also be applied in subsea TTRD.

This work focuses on BPT and CCS, in both of which reducing static mud weight is an option to reduce ECD. From drilling hydraulics point of view, reducing mud weight will affect the following parameters

- ECD
- Frictional pressure drop across system
- Hydraulic impact force
- Hole-cleaning performance
    1. Cuttings slip velocity
    2. Cuttings transport ratio
- Extended reach ability
- Wellbore stresses (stability)

Throughout this section, the field case will be studied and investigated to show how substantial impact of static mud weight reduction can be on these parameters. These analyses will serve as a basis to highlight potential possibility of integrating TTRD and MPD.

6.3.1 Impact of Mud Weight Reduction on ECD

The largest proportion of ECD is constituted by mud weight while a small proportion is contributed by AFP losses. Any decrease in mud weight has a direct impact on ECD so that it decreases.

On another hand, as will be addressed in the following section that mud weight decrease also causes decrease of AFP loss. Thus, applying MPD will help to reduce mud weight and thereby ECD can be lowered to a level at which drilling through any narrow window becomes possible.

The well B-4B was drilled with mud weigh of 1.68 s.g. where ECD at flow rate of 658 l/min and ROP of 15 m/h had exceeded minimum fracture pressure gradient below 1977 m TVD.

Assume MPD were applied and mud weight to drill well was chosen to be 1.61 s.g. Based on observations from this study and a discussion with MI-SWACO tells that such a reduction of mud density will not change fluid rheology. Maintaining all other operating parameters as before except mud weight, new ECD profile becomes as shown in Figure-6.5.

As seen from Figure-6.5, ECD has overbalanced pore pressure curve so that any reservoir influx is secured. Likewise, ECD is far below minimum fracture gradient. No loss circulation risk is observed.

If BPT of MPD utilized, well is dynamically overbalanced throughout drilling. When circulation is stopped to make connection the lost AFP is automatically replaced by back pressure at the surface. If CCS used, there is no need for back pressure to be applied since circulation is not stopped either while drilling and connection time.

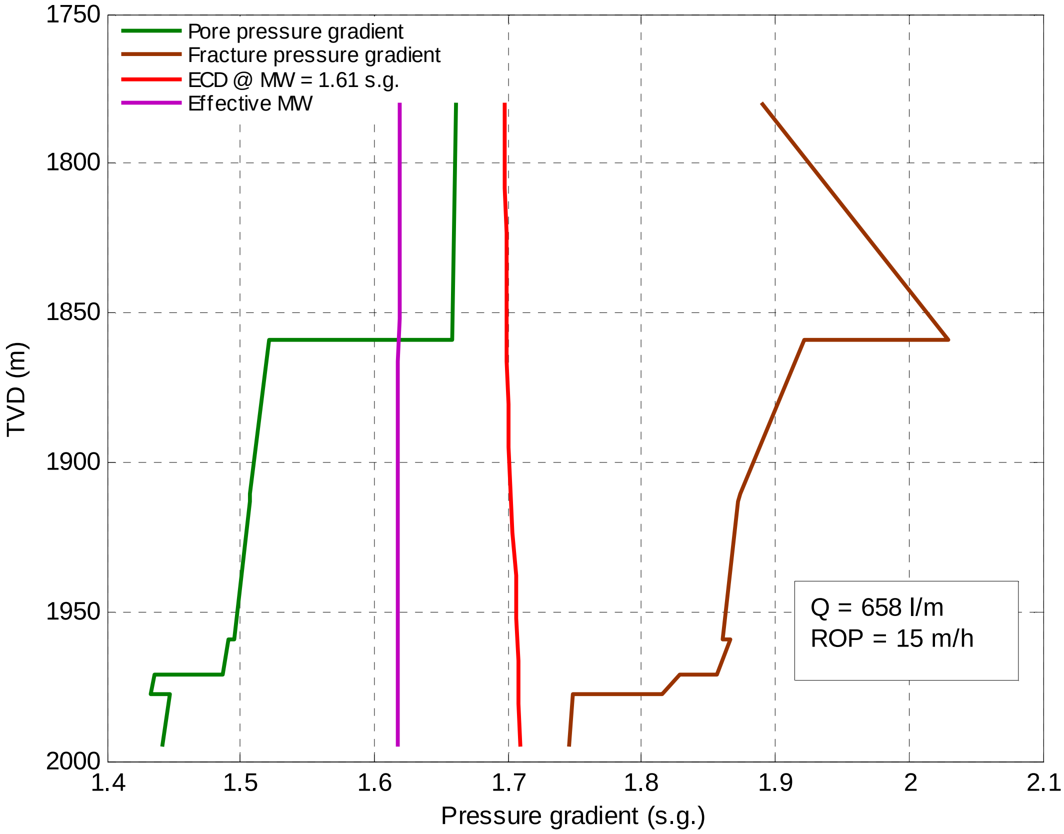


Figure-6.5: ECD for OH section in MPD mode for static MW = 1.61 s.g.

As to how much to reduce mud weight, this is situation specific: it will depend on narrowness of drilling window, length of open-hole section, well-bore stability and hole-cleaning performance.

ECD behaviour with pumping rate at both mud weights is given in Figure-6.6. The right side of arrow indicates sufficient hole-cleaning zone while the left side shows insufficient hole-cleaning zone.

Observation is that there is a point in ECD curve that corresponds to minimum bottom-hole pressure. Probably, that is this reason that in some sources flow rate at this point has been called as optimum flow rate. However, this approach is not true from practical perspective particularly because of hole-cleaning. At flow rate 200 lpm cuttings concentration reaches a value above that concentration of cuttings will contribute to ECD increase. For this reason 200 lpm is citric flow rate. In fact, minimum operational optimum flow rate will be much higher than this.

Experience from TTRD wells shows that minimum operation pumping rate is 600 lmp. Below 600 lpm hole-cleaning becomes a problem. The reason why result from simulations performed shows such a low critic flow rate (critic annular velocity) will be clarified in Part 6.3.4.

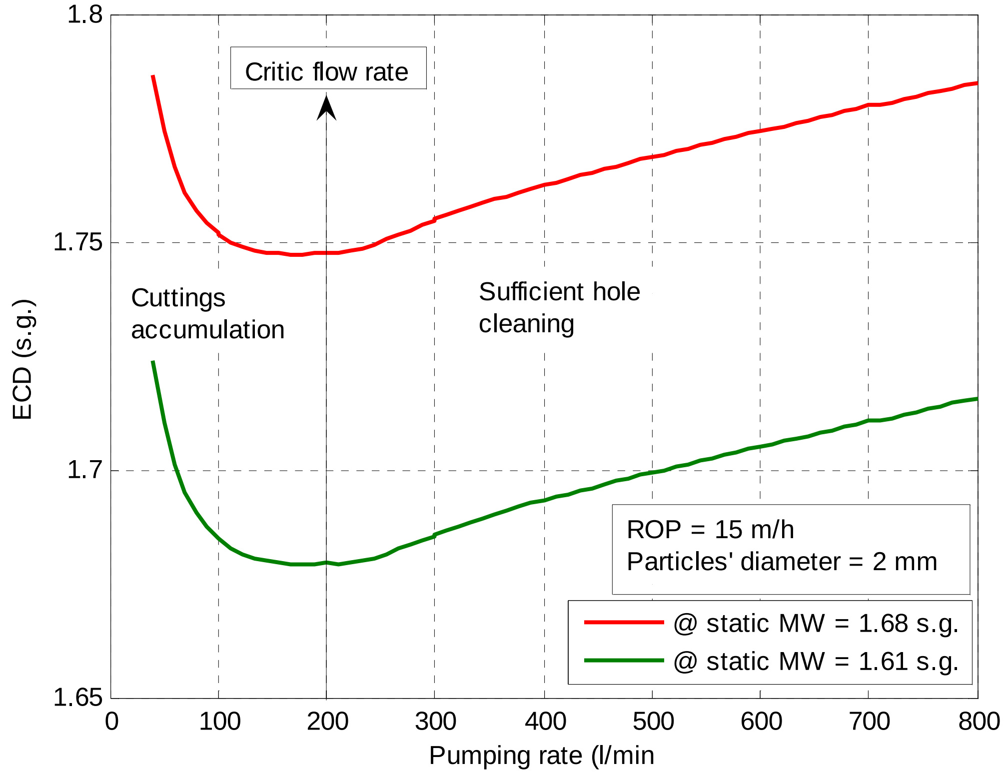


Figure-6.6: For two different mud weights, ECD vs. pumping rate curves

6.3.2 Affect of Mud Weight Reduction on AFP

Frictional pressure loss equations are proportional function of mud density. Decrease in density will contribute to reduction of pressure losses through flowlines, drillstring, bit and annulus if viscosity is kept constant.

This will result in an overall drop of system pressure loss and thereby the energy used to circulate mud through drilling system will be lowered. To calculate and compare pressure losses at different fluid densities, a Matlab program was developed by use of the theory given in Section-4. The actual well data was used and result obtained for drillstring pressure loss is shown in Figure-6.7.

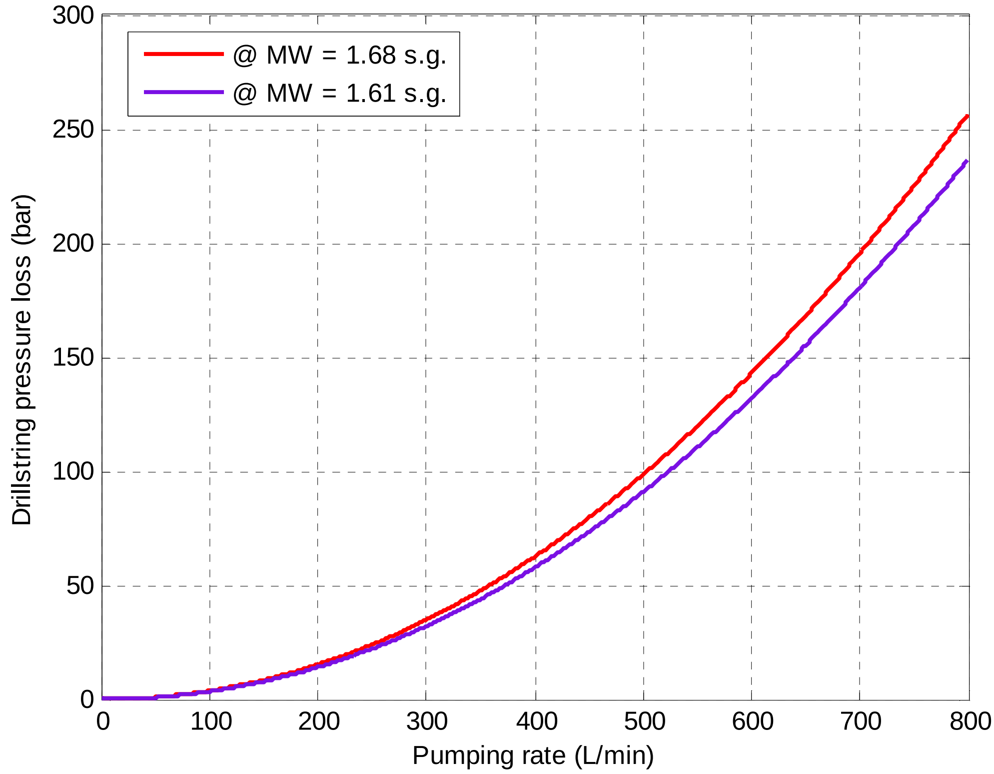


Figure-6.7: Pressure loss in the drillstring for two mud weights. (Well: 34/10-B-4B)

From StatoilHydro's experience, TTRD wells drilled through 7'' tubing/liner by 3.5'' drillpipe maximum flow rate achieved has been up to 850 lpm. Operational and sufficient flow rates for good hole-cleaning usually change around (650-700) lpm.

As seen from Figure-6.7 small decrease of mud density results in considerable reduction of drillstring pressure loss at practical flow rates. Difference between two curves becomes even substantial as pumping rate rises. At 700 lpm difference is around 10 bar that may be a contribution to reducing total system pressure loss.

Pressure loss across drill bit is shown in Figure-6.8. Difference in pressure loss across bit when mud density reduced is 1 bar at 700 lpm. Nevertheless, difference is very small but can be more substantial depending on TFA of bit and decrease in mud density.

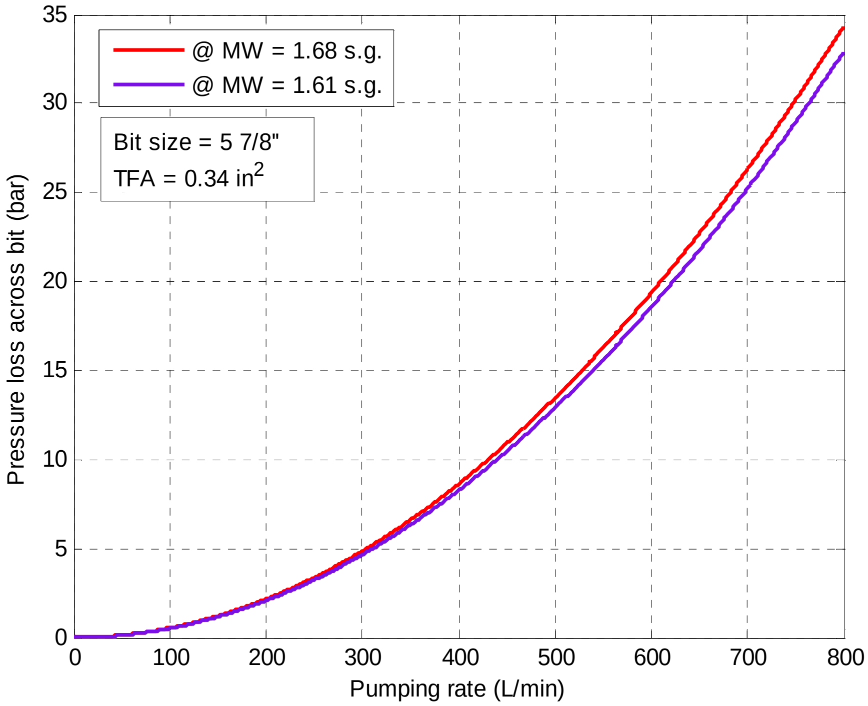


Figure-6.8: Pressure loss across drill bit for two mud densities. (Well: 34/10-B-4B)

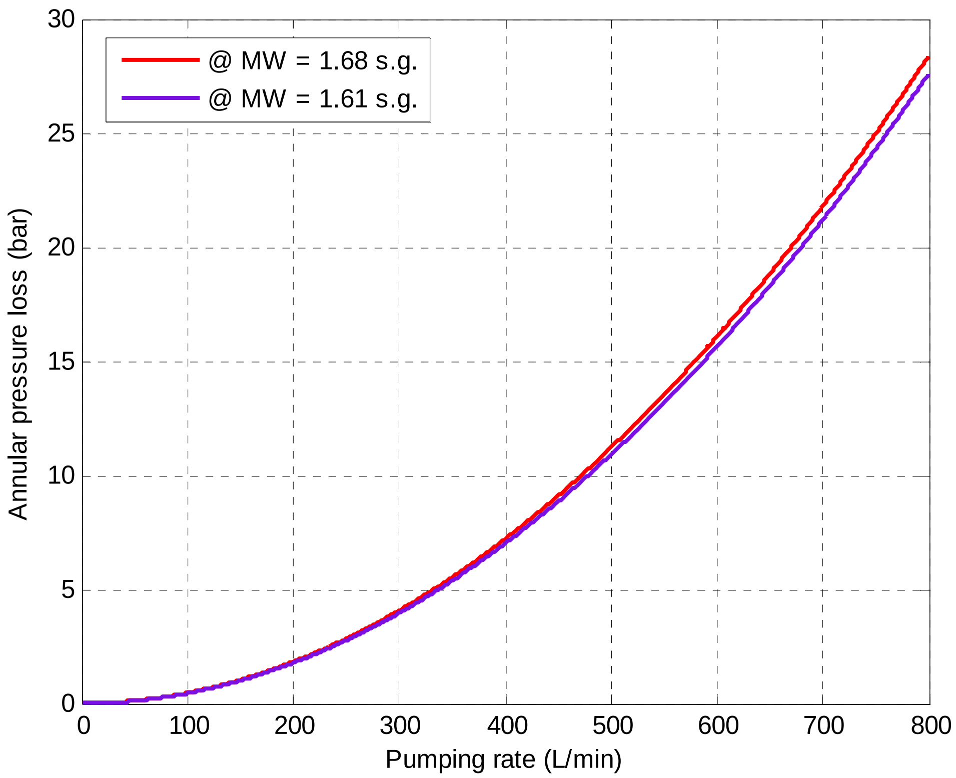


Figure-6.9: Pressure loss in annulus for two mud densities. (Well: 34/10-B-4B)

Annular frictional pressure loss is one of the most important drilling parameters so that allowable ECD, achievable flow rate (annular velocity) as well as ROP are linked to it. Any practical and acceptable technology giving less AFP is encouraged. Pressure loss in annulus for two mud densities is given in Figure-6.9.

Similar trend to bit pressure loss is observed and even less difference than in bit is seen. There can be a situation where effect may be substantial for instance if 3.5’’ drillpipe is used for drilling through 5’’ tubing.

Lowering mud density doesn’t result in a dramatic decrease of pressure loss in some parts of drilling system such as bit and annulus. However, it has a substantial effect on total system pressure loss. Frictional pressure loss for drilling system of the well B-4B is given in Figure-6.10. The shown is that pressure loss in system can be lowered up to 15 bar for this particular case. Note that pressure loss in surface flowlines is not included only drillstring, bit and annulus pressure losses are present.

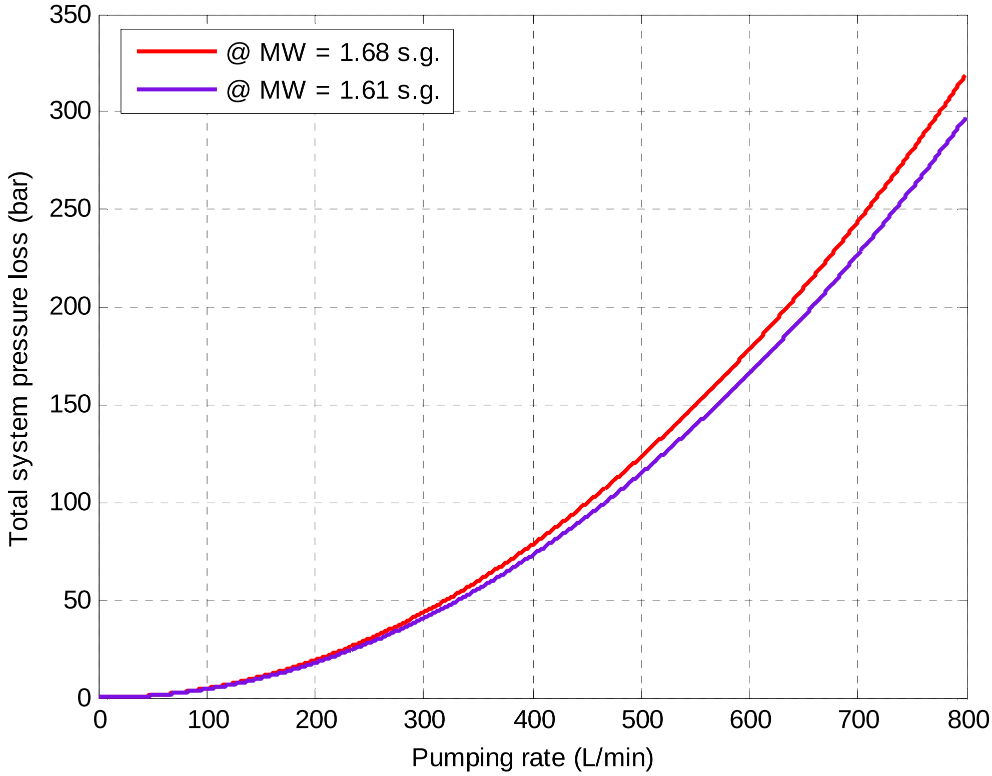


Figure-6.9: Total system pressure loss for two mud weights. (Well: 34/10-B-4B)

The similar results shown in Figure -6.11 are obtained from Wellplan software. Both outcomes show possible frictional pressure loss decrease due to mud weight decrease.
In slim-hole drilling like TTRD, pressure losses usual are higher than that of normal drilling operation if compared at the same pumping rate. The longer the well the higher the pressure losses are, and in these cases MPD can make improvement.

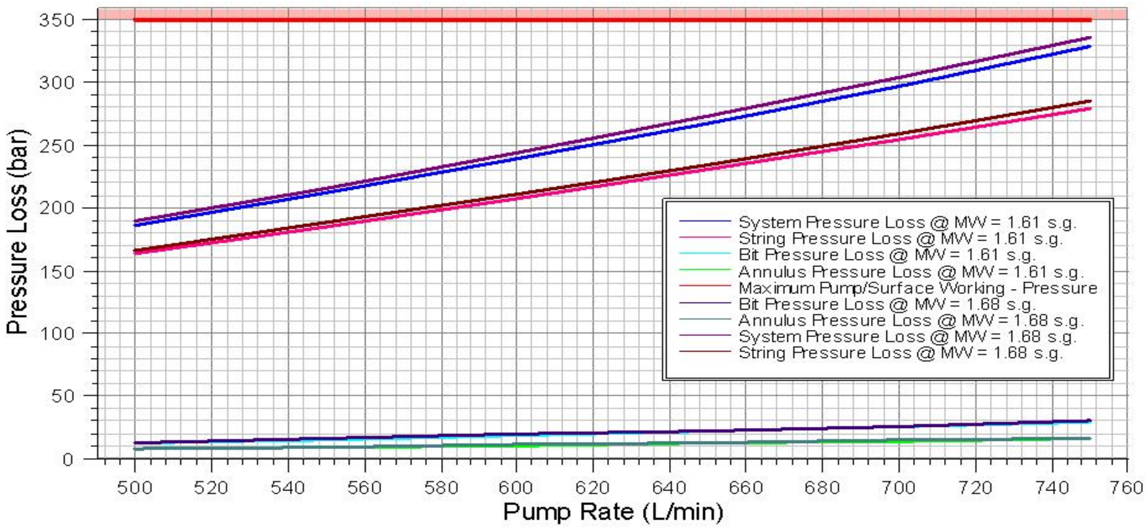


Figure-6.11: Pressure losses in drilling system and its components for two mud densities, the result from wellplan. (Well: 34/10-B-4B)

6.3.3 Mud Density Effect on Hydraulic Impact Force

Jet impact force is significant parameter used in hydraulic optimization issues. In bit optimization, common assumption is that the best and fast removal of cuttings from the beneath of bit is achieved at maximum impact force.

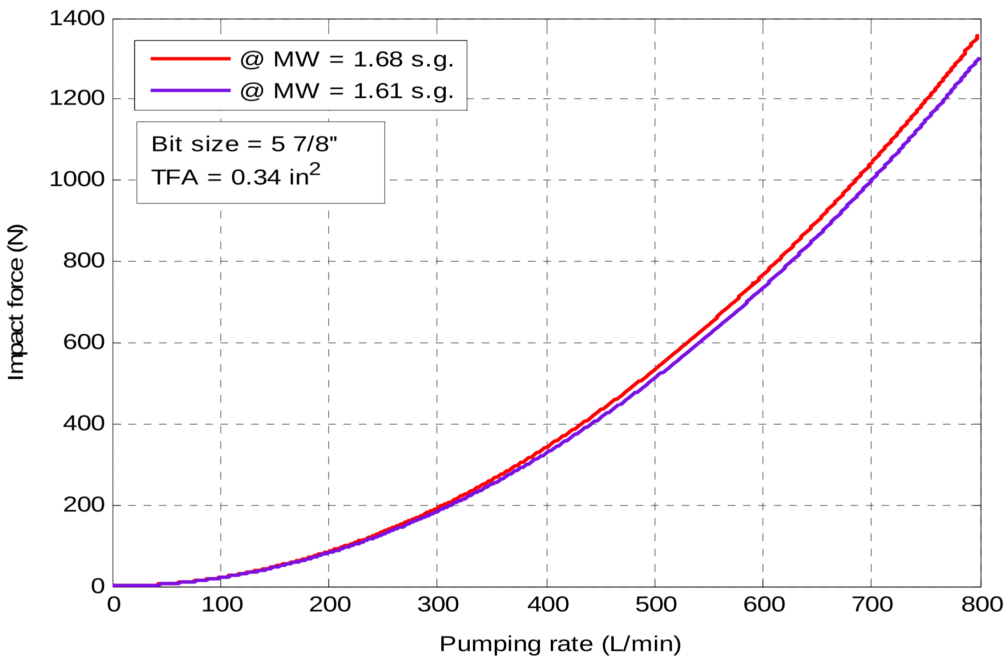


Figure-6.12: Hydraulic impact force vs. pumping rate for two mud weights

This force is proportional function of fluid weight. Jet force will be reduced when density is lowered by applying MPD. Using Eq. (4.48), hydraulic impact force is calculated at two fluid densities. The results are plotted and given in Figure-6.12

There exists a small difference in results. Difference between two curves at 700 l/min is roughly 50 Newton of force that is equivalent to about 5 kg mass. This effect may be ignored since it is very small.

6.3.4 Impact of Mud Weight Change on Hole-Cleaning Performance

As a drilling practice, operating parameters and properties of drilling fluid are designed and kept so that sufficient hole-cleaning can be attained and maintained. From StatoilHydro's experience, hole-cleaning in TTRD has not been reported as a serious challenge except cases where annular velocity was limited.

Any change of mud properties can influence hole-cleaning that may be positive or negative. When applying back pressure or CCS technique of MPD, usually reducing weight of drilling fluid is considered as an ability to drill in tight pressure margins.

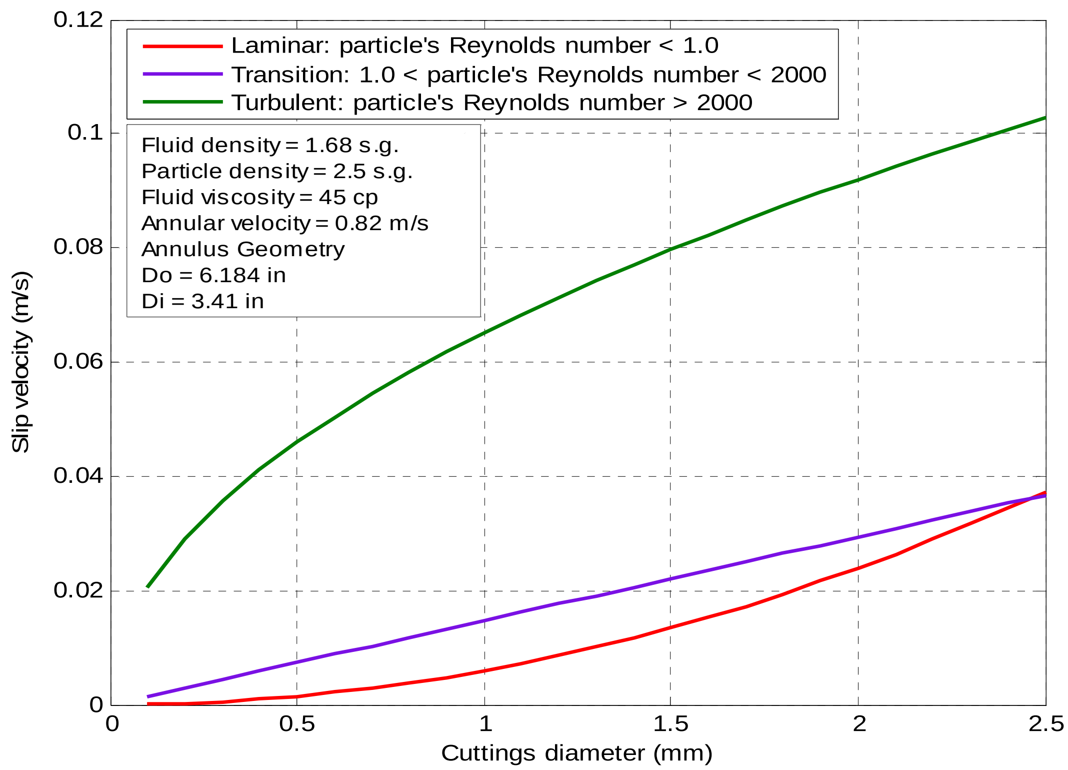


Figure-6.13: Cuttings slip velocity vs. their diameter

In hole-cleaning importance of buoyancy effect appears that depends on density difference. Buoyancy effect assists in having cuttings floating and reduces their slip velocity.

The higher the density difference between fluid and particle the faster the particles will settle. Here cuttings diameter plays a role as well. From reports of TTRD wells (StatoilHydro) observation is that largest particles are typically 2.5 mm and on average it has been roughly 1.5 mm.

Slip velocity of particles based on their diameter and particle's Reynolds number is given in Figure-6.13. Slip velocities of cuttings increase over size increase as expected. In the example well chosen, particles' slip velocity follows the trend shown by red line. Namely particles' Reynolds number is less than 1.0.

Concern here is to see how this trend will change if fluid density decreased. At two various mud weights, resulting curves for slip velocities are given in Figure-6.14

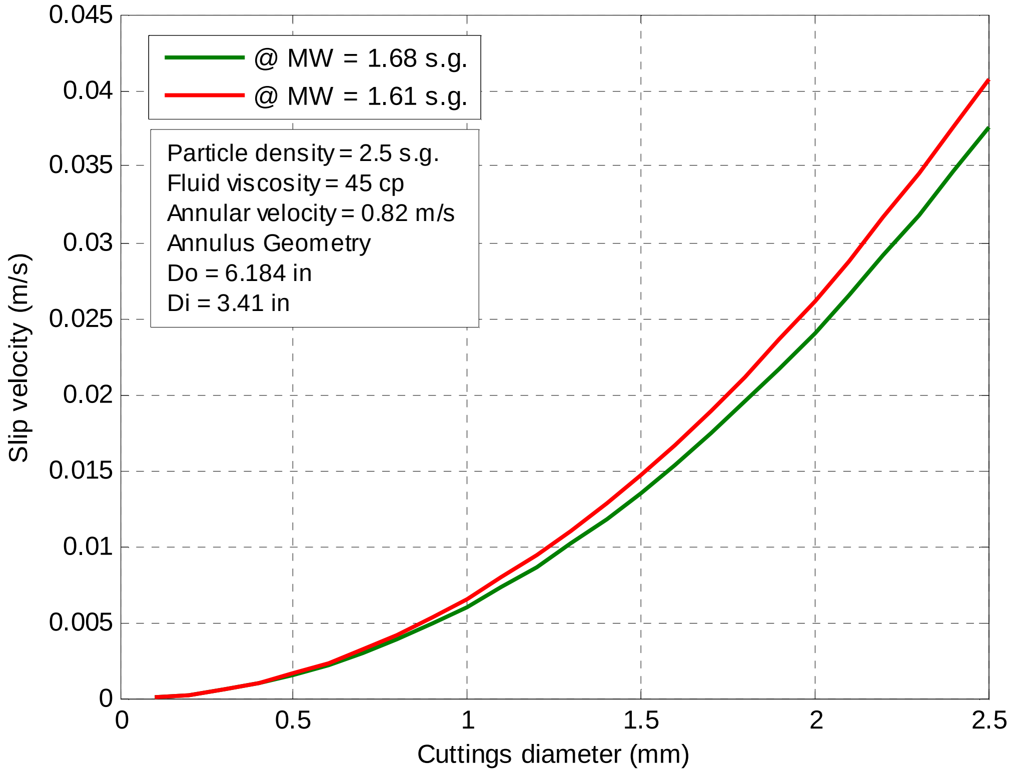


Figure-6.14: Slip velocity behaviour for two drilling fluid densities

Difference between two curves is very small e.g., at largest particle expected the magnitude of this difference is 0.003 m/s. This value is impractical to consider.

To perform further analysis concerning hole-cleaning, 2.5 mm largest particle size anticipated in TTD is chosen.

In the following, cuttings rise velocity in various parts of well with presence of annular, slip and annular critic velocities are looked into. Rise velocity is net upward travel velocity of cuttings that is usually below annular average velocity.

Slip velocity of cuttings is different from zero. When drilling the well B-4B operating flow rate was 658 lpm with average ROP ranged between 10 and 15 rpm. Based on these data velocity profiles versus measured well depth are obtained as shown in Figure-6.15.

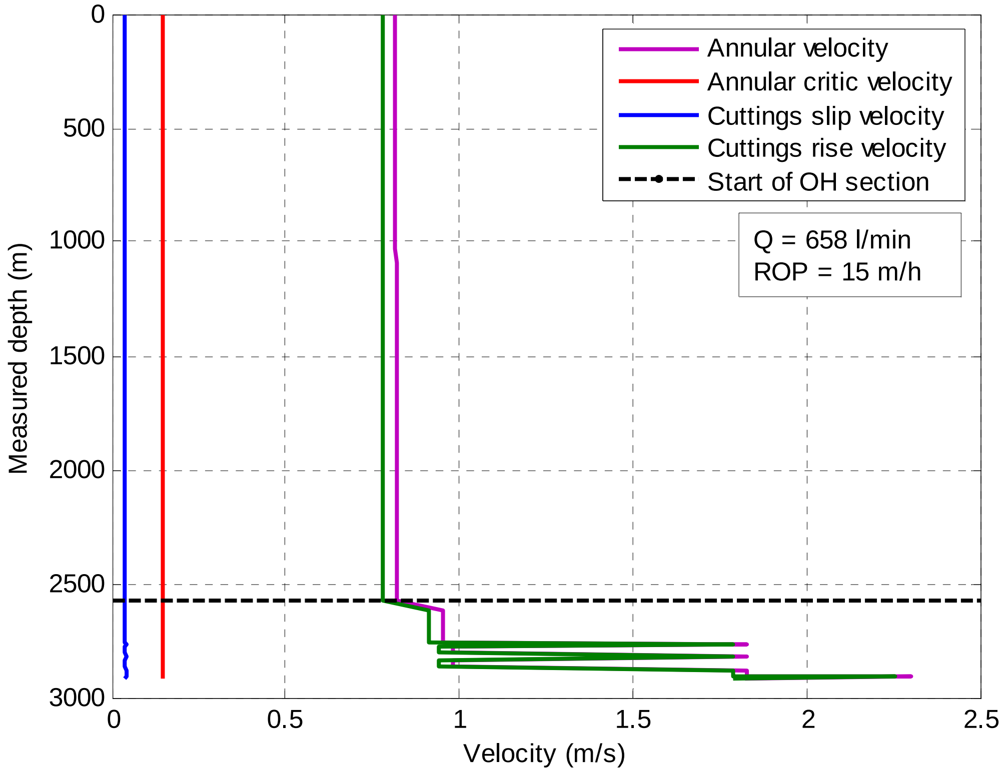


Figure-6.15: Velocity profiles in throughout the wellbore

Note that, annular critic velocity is very small compared to what has been observed in practice. Underlying reason is that slip velocity calculations assume vertical hole. However, the well has highly deviated well path. Practical annular critic velocity observed in TTRD operations has been around 0.5 m/s.

Pink and green lines are representing annular and cuttings rise velocities, respectively. Difference between these two is due to slip velocity. Slip velocity in open hole section has shown an increasing tenancy due to reduced viscosity in narrower annulus.

Figure-6.5 showed that well B-4B would have been drilled by employing MPD and reducing static fluid weight. Velocity profiles through well-path for two mud densities are given in Figure-6.16.

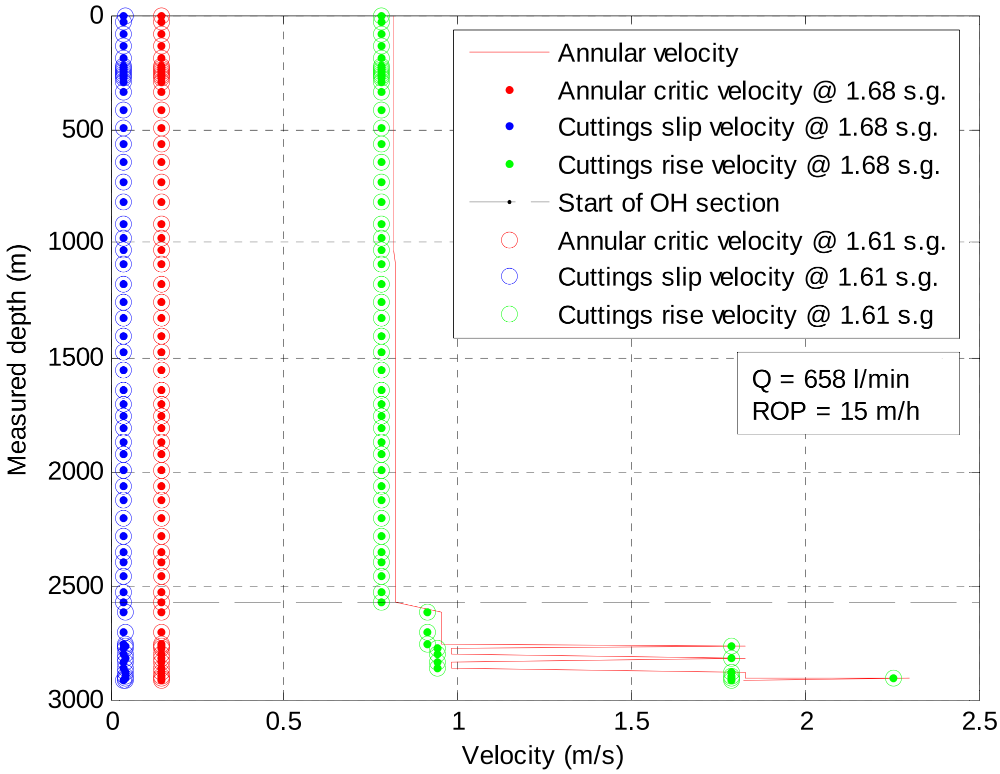


Figure-6.16: Velocity profiles for two drilling fluid densities

Expected differences between slip, rise and annular critic velocities are very small so that they are not observable in big scale plot. To see the difference, velocity profiles are separately plotted on relevant scales as shown in Figure-6.17, 6.18, 6.19. Figure-6.17 highlights change in slip velocity of particles with reduced mud weight.

One thing being even clear here is the increase of slip velocity in open-hole section and in various intervals of open-hole section. This occurs because of the thinning of drilling fluid due to less flow area in open-hole section.

Behaviour of cuttings rise velocity with respect to mud density change is given in Figure-6.18. Quite slight decrease of rise velocity is seen with decreased fluid density. Figure-6.19 shows annular critic velocity profiles for two densities.

Slip velocity increase results in increase of cuttings concentration that yields to higher annular critic velocity. This means that the lighter the mud the higher the annular critic velocity will be.

The overall assessment of what happen with hole-cleaning can better be given by cuttings transport efficiency. Based on change of slip and annular velocity profiles the cutting transport ratio is given in Figure-6.20.

The difference between two transport efficiency profiles is as low as 0.3-0.4 %. Such a small drop in transport efficiency is neglected in practice.

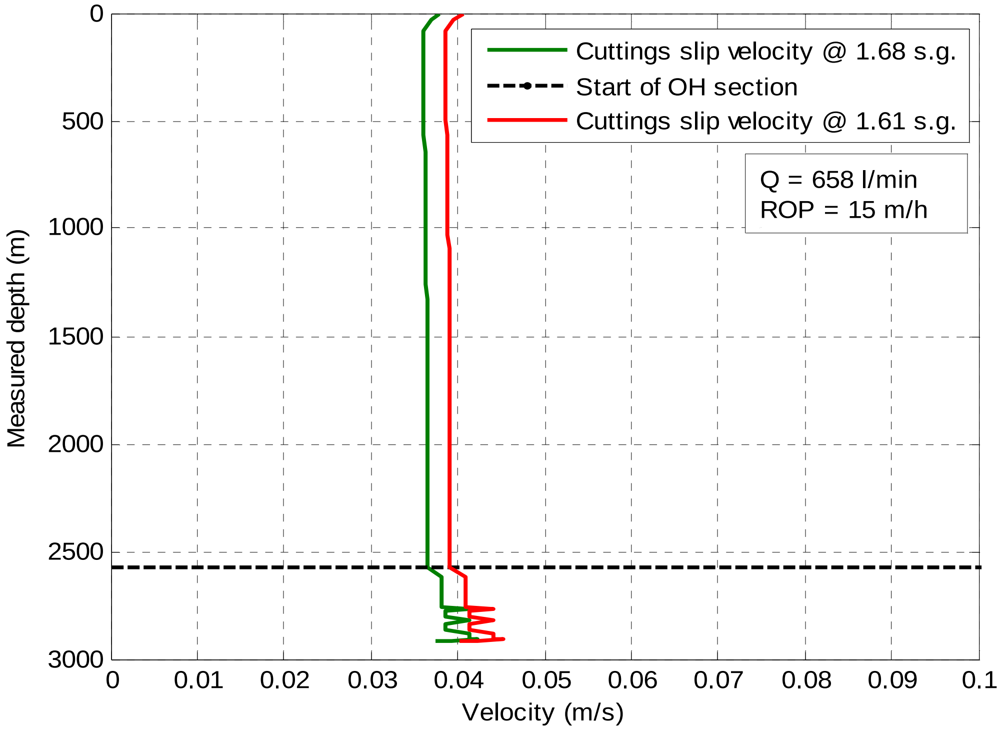


Figure-6.17: Slip velocity behaviour for two mud weights

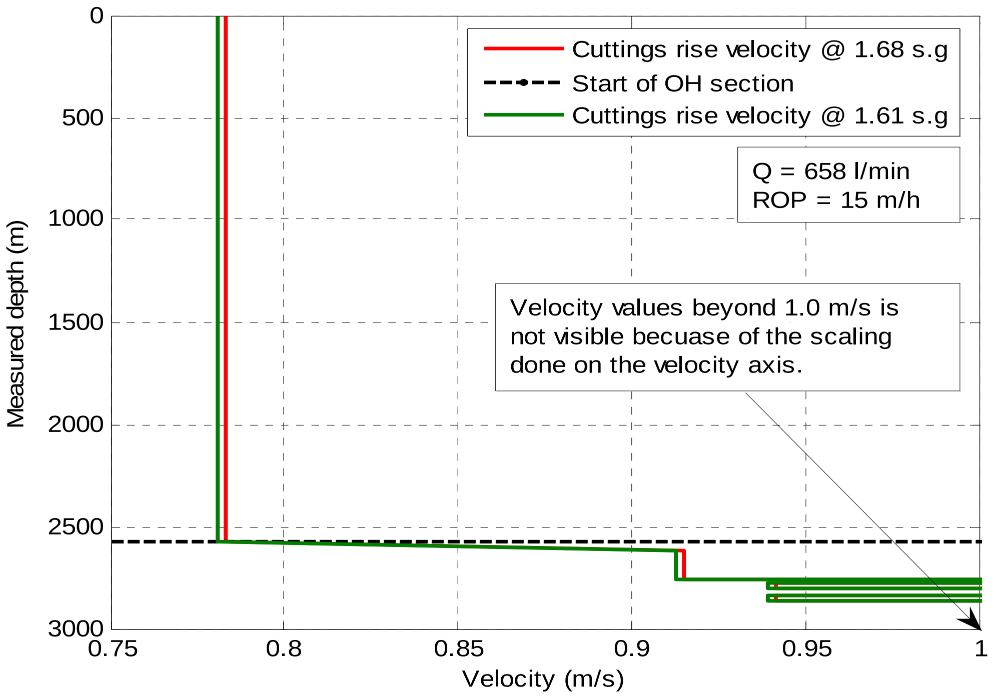


Figure-6.18: Cuttings rise velocity behaviour at two different mud weights

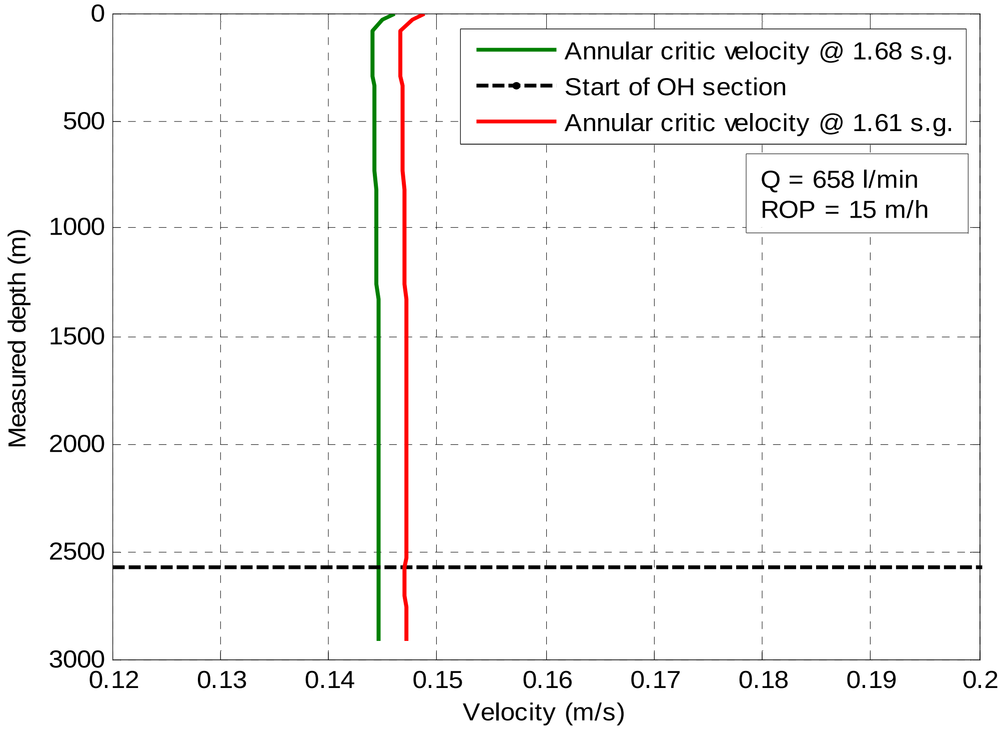


Figure-6.19: Annular critic velocity behaviour for two mud weights

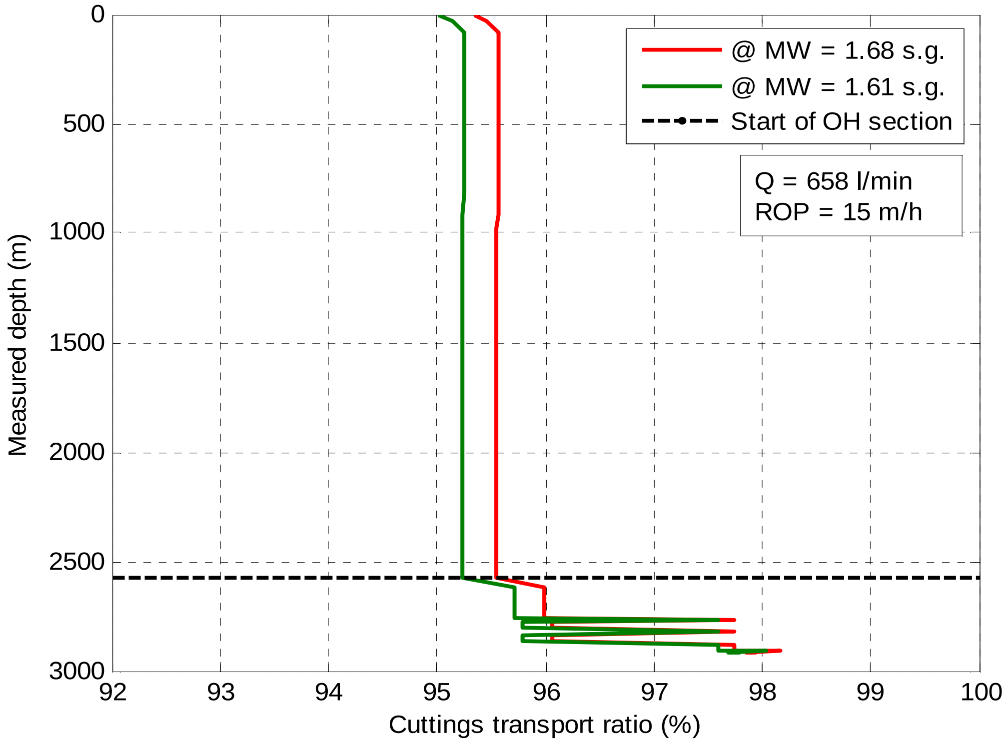


Figure-6.20: Cutting transport efficiency behaviour for two mud weights

6.3.5 Extended Reach Ability of MPD

MPD opens ways for drilling campaigns in circumstances where conventional drilling can not be applicable. In reach drilling, wells may not be drilled to their target unless extra casing points are set. Extra casing points are not accepted in slim-hole drilling as TTRD. Application of MPD helps to address this situation so that drilling reach can be extended.

In Figure-6.5 it was showed if a lighter mud were utilized it could have been possible to manage ECD within drilling window. AFP increases over extended length and so increases ECD.

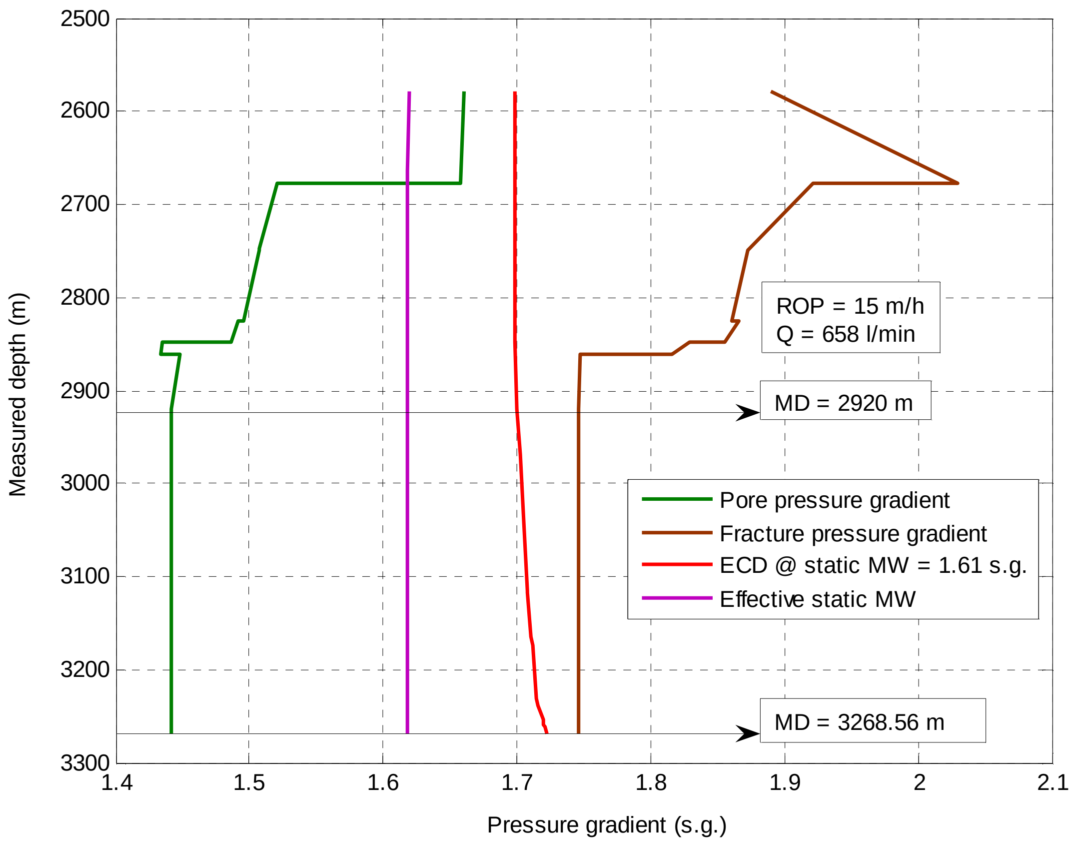


Figure-6.21: ECD profile for mud weight = 1.61 s.g. over planned well-path (B-4B)

As an example case 1.61 s.g. was used in above analysis done. Assume MPD were employed to drill the well B-4B with this mud weight and the same pressure margin applies for undrilled section (2920-3268 m MD). Concern is about ECD profile behaviour with respect to extended wellpath to the planned TD.

In Figure-6.21 the shown is demonstration of ECD profile from exit point (KOP) to the total planned MD. The observation is that undrilled 348 m open-hole section could have been drilled to hit the target. The extended wellpath is represented by red line in 3D plot given in Figure-6.22. This wellpath in fact was the part of planned wellpath.

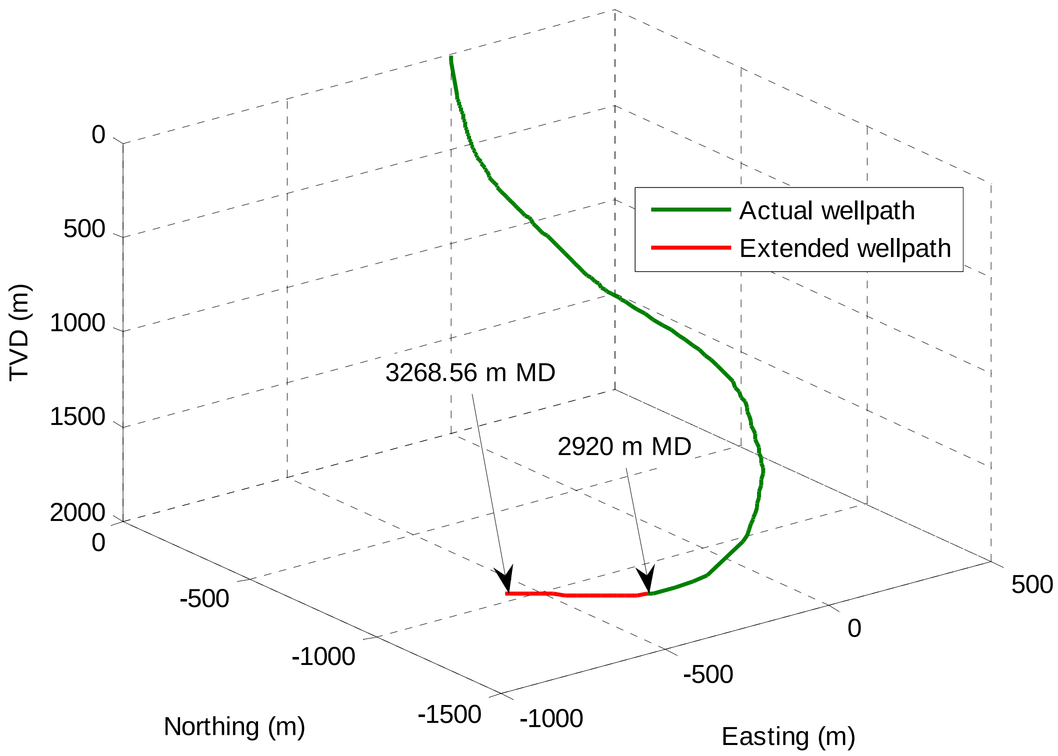


Figure-6.22: Actual wellpath and extended wellpath by application of MPD

6.3.6 MW Impact on Wellbore Stresses

To determine a safe operable window for mud weight to be used is an importance matter. Mud weight being out of this safe margin can result in wellbore stability problems. These problems include

- Wellbore breakout, further leading to collapse caused by low mud weight
- Mud loss, lost circulation and formation fracturing caused by high mud weight
- Tight hole caused by low mud weight

During drilling pre-existing stresses are redistributed as the supporting rock is removed through drilling and replaced by drilling mud. Resulting stresses can lead to both shear and tensile failure within wellbore.

If mud pressure is too low, the stress on surrounding rock becomes too high and shear failure occurs. The opposite can lead to tensile failure.

Mismanagement of wellbore pressure yields to hole instability. In conventional drilling, tackling stress related drilling problems is a challenging due to improper borehole pressure control.

MPD application will enable to manage wellbore pressure more flexibly and properly. As talked about in Section-3, the hydraulic model engaged in automated MPD system helps in accurate pressure control.

Unlike conventional drilling, automatic pressure control both in BPT and CCS can maintain wellbore pressure within a safe margin. In this regard, MPD will reduce and may even fully eliminate wellbore instability.

7 Discussion

The results from performed analysis were given and hydraulics of TTRD was investigated from a perspective of integrating it with MPD. Problem was addressed in terms of drilling hydraulics parameters.

Analysis assumed back pressure or CCS techniques of MPD. Aim has been to find out feasibility of MPD in TTRD campaigns. Both CCS and BPT are well suited for platform based TTRD campaigns.

Primary concern has been over ability of MPD allowing for mud weight reduction. In the foregoing, mud weight of 1.61 s.g. was chosen to study a field case.

As seen from analytical results obtained use of lighter drilling fluid does have an effect on drilling hydraulics. Effect of reducing mud weight was observed on system pressure losses and hole-cleaning. Use of MPD will not only enable us to drill through tight pressure margins but also promises reduction of pressure losses in system.

Analysis concerning hole-cleaning showed that reducing mud weight can influence hole-cleaning, primarily cuttings removal. Cuttings slip and rise velocities, annular critic velocity and cuttings transport efficiency were analysed.

Increase of particle slip velocity and reduction of rise velocity of cuttings with reduced mud weight were witnessed. Likewise, annular critic velocity was shown to rise with respect to decreased mud density.

The overall impact of using relatively light drilling fluid on hole-cleaning can be viewed in terms of cuttings transport efficiency. Variation in slip velocity directly influences hole-cleaning performance. Removal efficiency is dependant on slip velocity of fragments and annular velocity. In the foregoing analysis, annular velocity of fluid was kept constant to see net effect due to change of mud density.

The results gained from simulations performed in Drillbench software showed that removal efficiency falls with reduced mud weight as shown in Figure-5.20. The difference appearing between cuttings transport ratios is small for this specific case. It can be significant depending on amount of density decrease and annular stream velocity.

Pumping rate can be increased to compensate for decrease in cuttings transport efficiency. In this regard, being able to have pressure losses reduced due to reduced mud density is an advantage.

For this reason, a small amount of increase in pumping rate is necessary to keep the same removal efficiency. The comparison of this result with original transport ratio (TTRD without MPD) shows almost no difference as given in Figure-7.1.

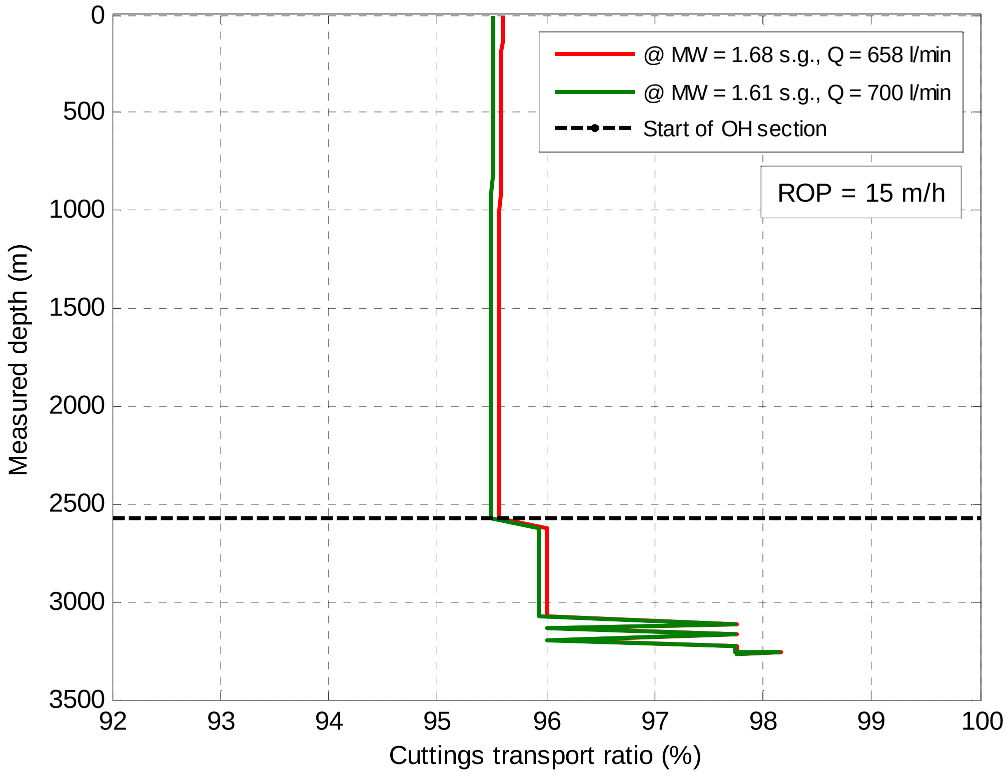


Figure-7.1: Cuttings transport ratio at two different flow rates and MWs

All these analysis were conducted based on largest cuttings size expected in TTRD. Cuttings sizes vary during drilling and smaller sized particles form the largest proportion of overall cuttings. Likewise, slip velocity of small cuttings will be less than that of biggest particles. For this reason, in practice difference in transport efficiencies will be disappearing.

It was shown that extended drilling reach can also be improved by applying MPD. Ability of adding/removing and controlling back pressure at the surface enables better management of wellbore pressures and better control over borehole instability. Both CCS and BPT will provide accurate pressure control. This will help to maintain wellbore pressure as close as possible to the in-situ stresses and prevent stability problems.

Cost, footprint, equipment shipment, well control and accuracy of wellbore pressure management are important issues when considering which of the discussed two MPD techniques would be more feasible. StatoilHydro has used both techniques in the North Sea (E.g. Kvitebjørn application). StatoilHydro’s experience shows that the cost of conducting BPT of MPD is roughly the same as for CCS.

From the discussions with MPD engineers at StatoilHydro it was known that there is an alternative CCS that is under development and will offer more competition in price issue. As for footprint it is difficult to mention a clear advantage or disadvantage between CCS and BPT. Both are different, CCS takes rig floor space while BPT requires nippling up on the well/BOP stack.

For well control, back pressure technique carries advantage in that an active RCD can serve as a well barrier. Passive RCD is neither recommended as main well barrier element nor accepted by StatoilHydro. An active RCD has been used. Engineers argue that combining CCS and BPT will give better well control. I.e., CCS unit will be used together with choke manifold and RCD. However, this may only be required for drilling in highly depleted reservoirs. CCS can't serve as well barrier since it only provides continuous flow down the drillstring.

In MPD operations the rig BOP stack is the main mechanical barrier with the combination of drilling mud and MPD equipment. In some circumstances, MPD can serve as a second common well barrier.

In both techniques conventional well control procedures and equipment will be used together with MPD equipment to handle well control issues. None of the two can address well control without conventional well control equipment and guidelines.

CCS will give a more stable ECD since it doesn't stop circulation during the drilling. BPT will have to stop and resume circulation from time to time that may result in some BHP spikes.

8 Conclusions

Trough-tubing rotary drilling may not always accomplish its goal because of challenging pressure regimes that often exist in mature fields. Integration of managed pressure drilling into TTRD operations could not only increase efficiency, but also enable TTRD operation where it is otherwise not possible to conduct. Combination of these two drilling methods may allow StatoilHydro to access unproduced reservoirs in its mature fields and maximize recovery.

MPD will overcome drilling problems that can not be solved and dealt with by TTRD method itself. TTRD being performed from platform can be conducted together with one of the two MPD techniques discussed, back pressure or continuous circulation system.

Both of these techniques will enable TTRD in wells where a narrow drilling window is present. The application of which of these two techniques depends on hydraulics and pressure management, footprint, cost and well control.

However, this study has not revealed that one is significantly better than the other.
The operation costs for both are approximately the same and none can be said to be advantageous or disadvantageous in terms of footprint. BPT gives better pressure control in a well control situation than CCS and thereby has an advantage over CCS for well control. Conventional drilling well control philosophy will still be the primary. The main benefit of CCS is that it enables more constant ECD however can't control annular pressure. If CCS unit is used together with the choke manifold and RCD it becomes able to control annular pressure with high accuracy.

Both of these techniques allow for reducing static mud weight and thereby reduce ECD while drilling through small pressure margins. Investigation shows that small reductions in mud weight will not strongly influence hole-cleaning performance. Sizes of cuttings in TTRD are typically small. For this reason cuttings transport efficiency will not be much affected by small mud weight decrease.

Using lighter drilling mud will cause pressure losses decrease in drilling system. This can help to increase pumping rate without exceeding ECD limit (fracture pressure). Flow rate increase will also assist in improving cuttings transport efficiency with increased annular velocity. This may help to raise ROP due to increased flow rate. Furthermore, the lighter the drilling mud the lesser the cost of it.

More accurate and proper pressure management and control by MPD will help to maintain wellbore pressure as close to in-situ stresses as possible. This will minimize and may even eliminate wellbore instability. Automatic and precise control will reduce pressure pulsation and maintain constant wellbore pressure. Constant wellbore pressure will reduce wellbore stress disturbance.

9 Recommendations

Performing more research will increase knowledge on MPD and enable secure operations. There is a need for further research for conducting MPD and TTRD together in a well. These include economic analysis on carefully selected wells, well control, equipment efficiency, reliability, cost, and the cementing and completion phases.

MPD operations are expensive since MPD doesn't only consist of equipment but also requires a lot of training. This means that the upfront investment is high and that will in particular reflect on the total cost if only a few wells are planned. For this reason, campaign consisting of many operations should ideally be planned. In that way the operational crews will be fully able to benefit from the experiences and thereby perform more efficient operations.

Since the overall cost of TTRD operation conducted together with MPD will increase. Economic analysis should therefore cover the particular cases and verify that the operations are economically feasible.

Wellhead equipment especially the Christmas tree will be subject to increased loads since some MPD equipment will be rigged up on conventional drilling equipment. Investigation covering this issue is recommended and it should cover all stresses that can be imposed on wellhead equipment.

Because of the narrow drilling window and small annular clearance in TTRD liner cementing and completion have been challenging. A study should be done to find out if employing MPD will improve situation and how will it address the cementing and completion phases.

If MPD equipment fails, the BHP may drop below the pore pressure. In this case, if risk reducing measures aren't introduced well control issues may arise. As risk reducing measures such as the equipment, routines and well control exercises to ensure capability of quickly changing to a conventional well control situation and efficiently circulating a kick out is to be considered.

Studying well control from this perspective will increase knowledge to understand and prevent such incidents. A research can also be done on ECD reduction tool and its possible application in TTRD. However, focus should be on the main influencing factors such as reliability, safety and cost.

Studying dual gradient drilling may open perspective for its application in Subsea TTRD.

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Appendices

Appendix-A

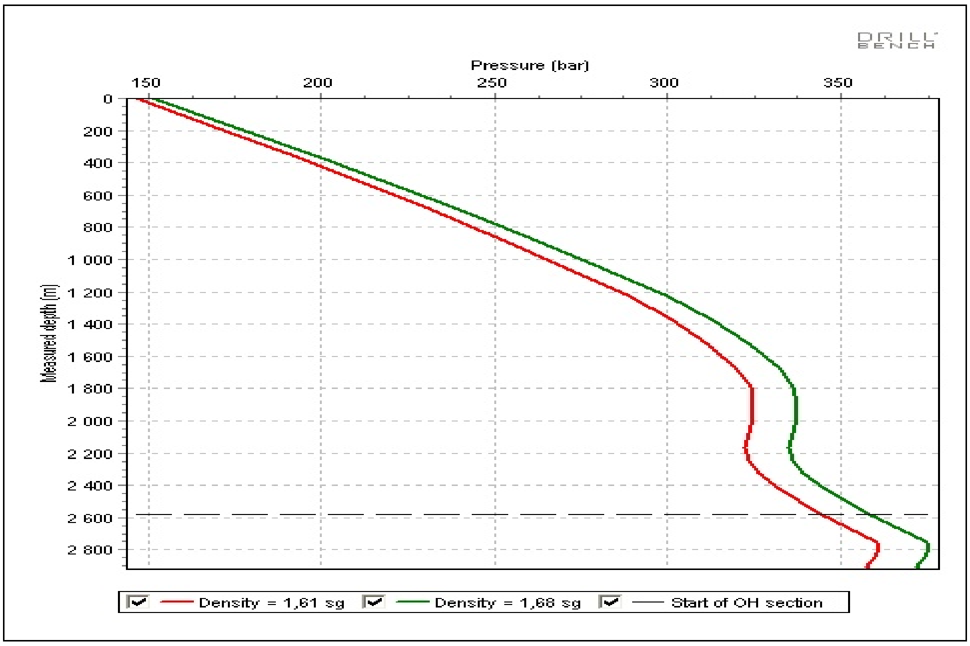

Figure-A.1: Pressure in drillstring for two mud weights.

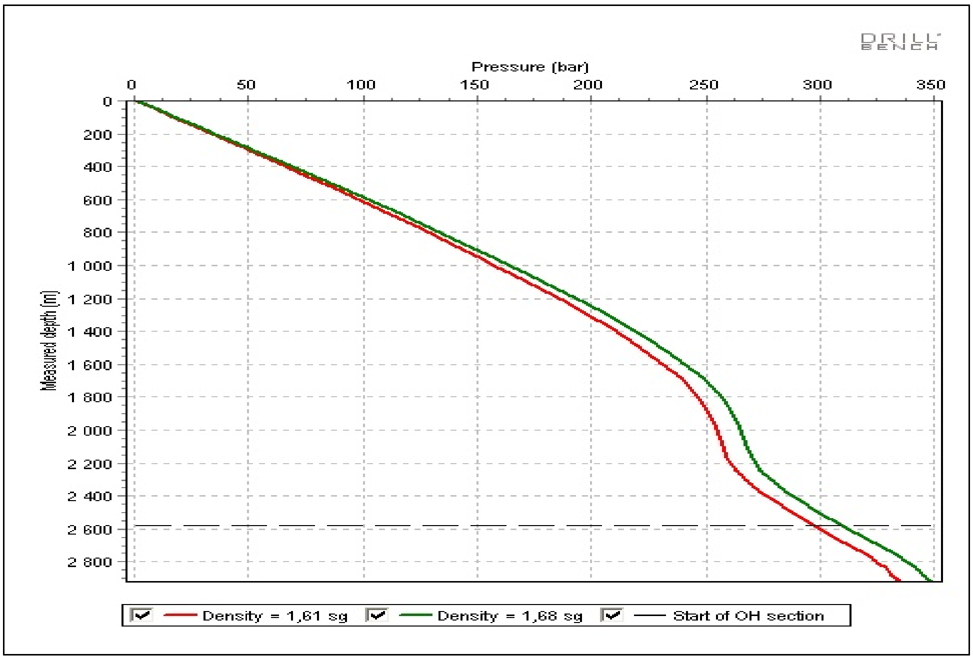

Figure-A.2: Pressure in annulus for two mud weights

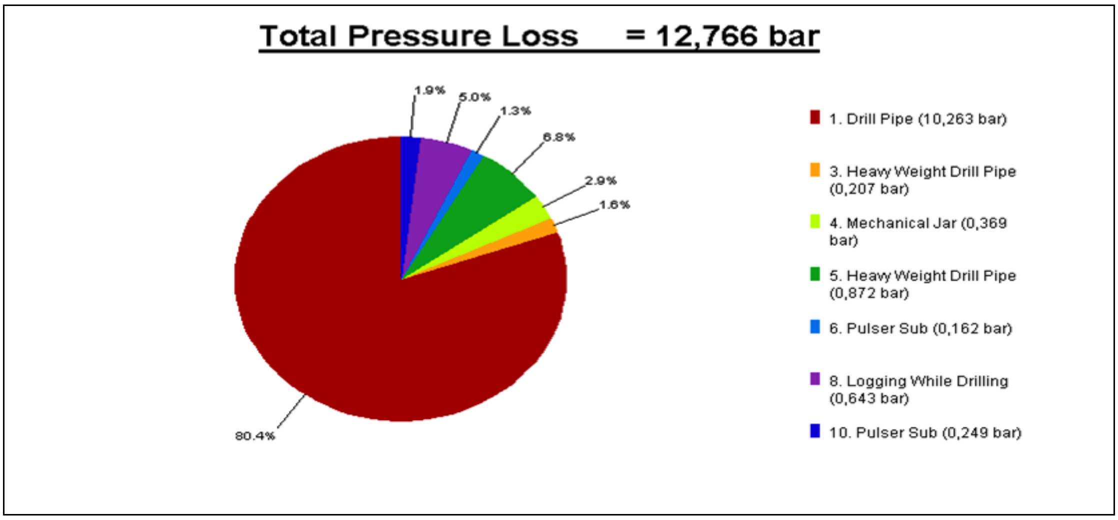

Figure-A.3: Annular pressure loss @ MW = 1.61 s.g. (from Wellplan)

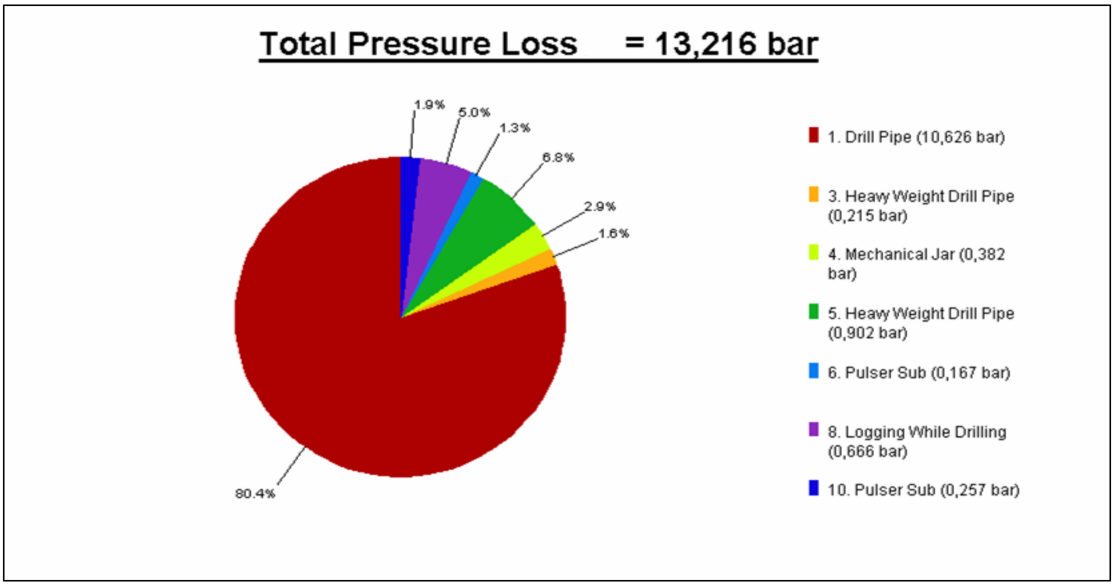

Figure-A.4: Annular pressure loss @ MW = 1.68 s.g. (from Wellplan)

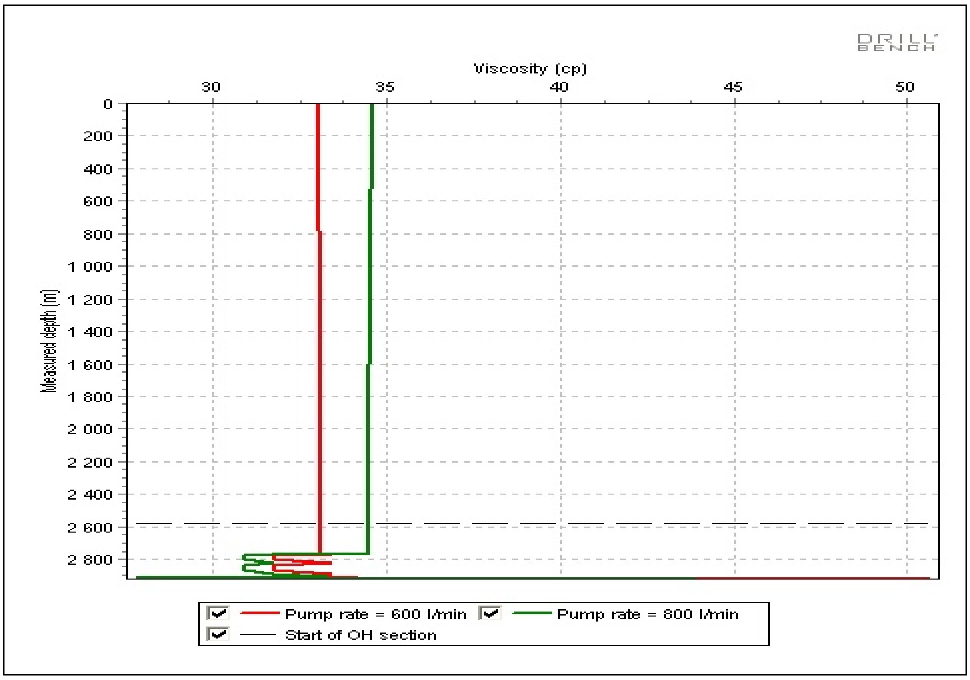

Figure-A.5: Equivalent viscosity in drillstring for two different flow rates

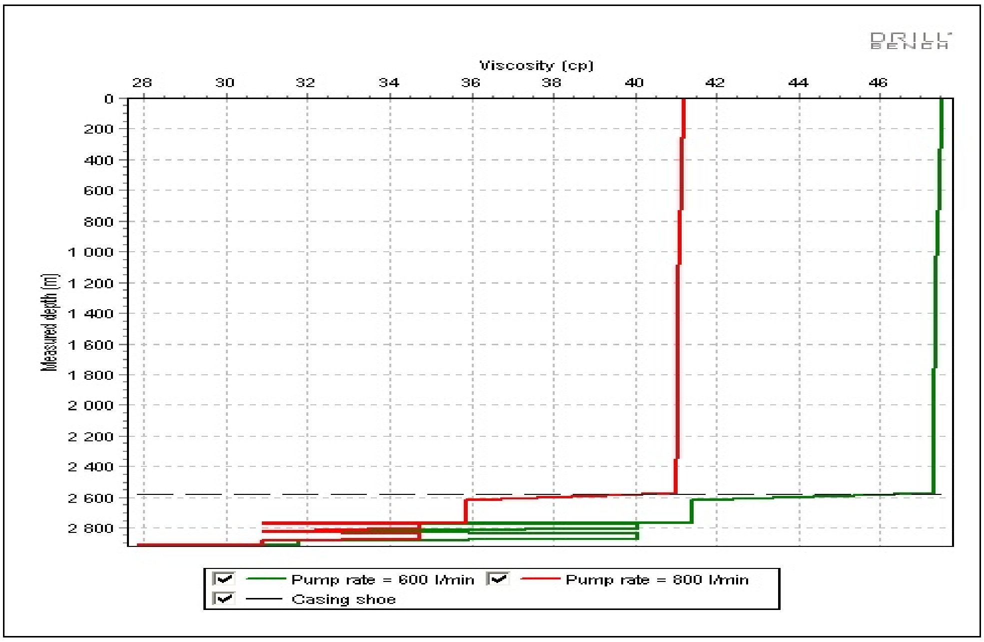

Figure-A.6: Equivalent viscosity in annulus for two different flow rates.

Appendix-B

Drilling data of well 34/10-B-4B

SURVEY LIST
(distance in meter, angle in deg.)

MD	Inc	AZI	TVD	TVDSS	X-Offset	Y-Offset
39.10	0.00	0.00	39.10	-41.60	0.00	0.00
214.50	7.87	125.13	214.00	133.30	8.31	-5.85
224.60	8.28	126.48	224.00	143.30	9.46	-6.68
234.71	8.56	127.44	234.00	153.30	10.64	-7.57
244.82	8.55	127.71	244.00	163.30	11.84	-8.49
254.93	8.48	127.37	254.00	173.30	13.02	-9.40
265.04	8.34	127.65	264.00	183.30	14.19	-10.30
275.15	8.09	128.00	274.00	193.30	15.34	-11.19
285.24	7.77	128.00	284.00	203.30	16.43	-12.04
295.33	7.38	128.42	294.00	213.30	17.48	-12.87
305.41	7.08	128.62	304.00	223.30	18.47	-13.66
315.49	6.91	128.81	314.00	233.30	19.43	-14.42
325.56	6.89	128.96	324.00	243.30	20.37	-15.18
335.63	6.98	129.87	334.00	253.30	21.31	-15.95
345.71	7.11	131.10	344.00	263.30	22.25	-16.76
355.79	7.21	131.63	354.00	273.30	23.19	-17.59
365.87	7.40	132.35	364.00	283.30	24.15	-18.45
375.96	7.65	133.79	374.00	293.30	25.11	-19.35
386.05	7.85	135.00	384.00	303.30	26.08	-20.30
396.14	7.99	135.43	394.00	313.30	27.06	-21.29
406.25	8.29	135.83	404.00	323.30	28.06	-22.31
416.36	8.69	136.06	414.00	333.30	29.10	-23.38
426.48	9.02	136.40	424.00	343.30	30.18	-24.51
436.61	9.42	137.32	434.00	353.30	31.29	-25.69
446.75	9.88	138.02	444.00	363.30	32.43	-26.95
456.91	10.36	138.55	454.00	373.30	33.62	-28.28
467.08	10.89	138.90	464.00	383.30	34.86	-29.69
477.28	11.56	139.06	474.00	393.30	36.16	-31.19
487.50	12.21	139.50	484.00	403.30	37.53	-32.78
497.74	12.72	140.21	494.00	413.30	38.96	-34.47
508.00	13.26	140.77	504.00	423.30	40.42	-36.25
518.29	13.70	140.99	514.00	433.30	41.94	-38.11
528.58	13.98	141.20	524.00	443.30	43.48	-40.03
538.90	14.25	141.39	534.00	453.30	45.06	-41.99
549.22	14.61	141.31	544.00	463.30	46.66	-44.00
559.57	15.02	140.97	554.00	473.30	48.32	-46.06
569.93	15.51	140.92	564.00	483.30	50.04	-48.18
580.32	16.03	141.08	574.00	493.30	51.82	-50.38
590.74	16.67	141.37	584.00	503.30	53.66	-52.66
601.21	17.60	141.72	594.00	513.30	55.57	-55.08
611.73	18.60	142.06	604.00	523.30	57.59	-57.65
622.31	19.45	142.30	614.00	533.30	59.71	-60.37

632.93	20.04	142.52	624.00	543.30	61.89	-63.22
643.59	20.48	143.05	634.00	553.30	64.13	-66.16
654.28	20.91	143.36	644.00	563.30	66.39	-69.18
665.00	21.36	143.42	654.00	573.30	68.69	-72.29
675.76	21.81	143.69	664.00	583.30	71.05	-75.47
686.55	22.34	143.76	674.00	593.30	73.45	-78.74
697.38	22.92	143.75	684.00	603.30	75.91	-82.10
708.26	23.53	143.92	694.00	613.30	78.44	-85.56
719.20	24.28	144.02	704.00	623.30	81.05	-89.15
730.21	25.20	144.16	714.00	633.30	83.75	-92.88
741.31	26.23	144.45	724.00	643.30	86.56	-96.79
752.50	27.12	144.70	734.00	653.30	89.47	-100.89
763.77	27.67	144.70	744.00	663.30	92.47	-105.12
775.07	27.98	144.69	754.00	673.30	95.52	-109.42
786.40	28.08	144.81	764.00	683.30	98.59	-113.77
797.73	27.97	144.81	774.00	693.30	101.66	-118.12
809.05	27.88	144.73	784.00	703.30	104.72	-122.45
820.37	28.03	144.52	794.00	713.30	107.79	-126.78
831.72	28.41	144.06	804.00	723.30	110.92	-131.14
843.11	28.89	143.59	814.00	733.30	114.14	-135.54
854.56	29.27	143.30	824.00	743.30	117.46	-140.01
866.03	29.48	143.16	834.00	753.30	120.83	-144.52
877.52	29.52	143.22	844.00	763.30	124.22	-149.05
889.01	29.53	143.36	854.00	773.30	127.60	-153.59
900.51	29.55	143.28	864.00	783.30	130.99	-158.14
912.01	29.63	143.29	874.00	793.30	134.38	-162.69
923.52	29.71	143.48	884.00	803.30	137.78	-167.26
935.03	29.75	143.50	894.00	813.30	141.18	-171.85
946.55	29.71	143.62	904.00	823.30	144.57	-176.45
958.05	29.46	143.82	914.00	833.30	147.93	-181.02
969.52	29.22	143.84	924.00	843.30	151.25	-185.56
980.97	29.04	144.05	934.00	853.30	154.53	-190.07
992.40	29.01	144.25	944.00	863.30	157.78	-194.56
1003.85	29.15	144.23	954.00	873.30	161.03	-199.08
1015.30	29.15	144.41	964.00	883.30	164.28	-203.61
1026.74	29.00	144.80	974.00	893.30	167.50	-208.14
1038.17	28.96	144.93	984.00	903.30	170.69	-212.67
1049.60	28.90	144.77	994.00	913.30	173.87	-217.19
1061.01	28.66	144.61	1004.00	923.30	177.05	-221.67
1072.39	28.41	144.33	1014.00	933.30	180.21	-226.10
1083.75	28.32	144.17	1024.00	943.30	183.36	-230.48
1095.12	28.38	144.34	1034.00	953.30	186.51	-234.86
1106.49	28.56	144.38	1044.00	963.30	189.67	-239.26
1117.89	28.71	144.25	1054.01	973.31	192.86	-243.70
1129.29	28.74	144.43	1064.00	983.30	196.05	-248.15
1140.70	28.81	144.73	1074.00	993.30	199.24	-252.63
1152.13	29.23	144.75	1084.00	1003.30	202.44	-257.16
1163.64	30.08	144.73	1094.00	1013.30	205.72	-261.81
1175.27	31.24	144.66	1104.00	1023.30	209.15	-266.65

1187.04	32.56	144.43	1114.00	1033.30	212.76	-271.71
1199.00	33.85	144.19	1124.00	1043.30	216.58	-277.03
1211.12	35.09	144.06	1134.00	1053.30	220.60	-282.59
1223.44	36.29	144.22	1144.00	1063.30	224.81	-288.41
1235.95	37.61	144.50	1154.00	1073.30	229.19	-294.53
1248.70	39.06	144.55	1164.00	1083.30	233.78	-300.97
1261.71	40.41	144.22	1174.00	1093.30	238.62	-307.73
1274.92	41.25	143.84	1184.00	1103.30	243.70	-314.72
1288.25	41.49	143.71	1194.00	1113.30	248.90	-321.82
1301.63	41.78	143.78	1204.00	1123.30	254.16	-328.99
1315.13	42.61	143.75	1214.01	1133.31	259.52	-336.31
1328.84	43.72	143.40	1224.00	1143.30	265.09	-343.85
1350.00	45.09	143.60	1239.12	1158.42	273.90	-355.75
1367.00	45.45	144.70	1251.08	1170.38	280.97	-365.54
1397.00	47.50	149.20	1271.75	1191.05	292.81	-383.77
1427.00	48.41	151.20	1291.84	1211.14	303.88	-403.10
1466.00	51.20	157.00	1317.02	1236.32	316.85	-429.89
1492.00	51.70	161.30	1333.23	1252.53	324.09	-448.89
1519.00	53.50	163.90	1349.63	1268.93	330.49	-469.35
1546.00	55.40	168.40	1365.33	1284.63	335.74	-490.67
1573.00	57.30	172.50	1380.29	1299.59	339.46	-512.83
1600.00	55.30	170.30	1395.28	1314.58	342.81	-535.04
1627.00	56.30	174.60	1410.46	1329.76	345.74	-557.17
1654.00	59.00	178.50	1424.91	1344.21	347.10	-579.93
1681.00	61.40	182.20	1438.33	1357.63	346.95	-603.35
1709.00	62.70	185.80	1451.45	1370.75	345.22	-628.02
1762.00	67.00	194.30	1474.01	1393.31	336.80	-675.17
1789.00	69.80	198.00	1483.95	1403.25	329.81	-699.28
1816.00	72.50	200.40	1492.67	1411.97	321.40	-723.40
1842.00	74.80	202.90	1499.99	1419.29	312.20	-746.59
1869.00	76.50	205.70	1506.68	1425.98	301.43	-770.42
1896.00	78.50	208.30	1512.53	1431.83	289.47	-793.90
1923.00	79.00	210.50	1517.80	1437.10	276.47	-816.97
1950.00	78.60	210.70	1523.04	1442.34	262.98	-839.77
1977.00	81.10	210.50	1527.80	1447.10	249.46	-862.64
2004.00	82.90	210.90	1531.56	1450.86	235.81	-885.63
2030.00	83.00	210.90	1534.75	1454.05	222.56	-907.77
2057.00	82.80	210.70	1538.08	1457.38	208.84	-930.79
2084.00	82.20	210.60	1541.61	1460.91	195.19	-953.82
2112.00	81.80	210.50	1545.51	1464.81	181.10	-977.70
2139.00	80.90	210.30	1549.57	1468.87	167.59	-1000.72
2165.00	78.60	210.60	1554.19	1473.49	154.62	-1022.77
2193.00	76.00	211.90	1560.35	1479.65	140.46	-1046.12
2221.00	73.10	214.20	1567.81	1487.11	125.74	-1068.74
2247.00	68.70	216.10	1576.31	1495.61	111.61	-1088.83
2273.00	64.80	219.00	1586.58	1505.88	97.06	-1107.77
2301.00	60.70	221.60	1599.40	1518.70	80.97	-1126.75
2329.00	57.90	223.70	1613.69	1532.99	64.67	-1144.46
2355.00	55.50	224.90	1627.97	1547.27	49.50	-1160.01

2382.00	52.60	226.60	1643.82	1563.12	33.85	-1175.27
2408.00	50.00	228.50	1660.07	1579.37	18.88	-1188.97
2421.00	48.50	229.10	1668.56	1587.86	11.47	-1195.45
2452.00	47.60	229.40	1689.28	1608.58	-5.99	-1210.50
2464.00	47.30	230.30	1697.39	1616.69	-12.75	-1216.20
2478.00	46.60	231.00	1706.95	1626.25	-20.66	-1222.69
2491.00	45.80	231.90	1715.95	1635.25	-28.00	-1228.54
2517.00	44.30	237.90	1734.33	1653.63	-43.03	-1239.12
2545.00	42.60	242.60	1754.66	1673.96	-59.73	-1248.68
2572.00	38.50	242.40	1775.17	1694.47	-75.30	-1256.78
2748.65	45.71	304.84	1911.91	1831.21	-180.49	-1245.65
2788.21	50.50	299.77	1938.33	1857.63	-205.38	-1229.97
2847.18	61.75	298.86	1971.14	1890.44	-248.01	-1206.06
2901.22	75.71	299.82	1990.70	1910.00	-291.79	-1181.43
2920.00	75.71	299.82	1995.33	1914.63	-307.58	-1172.38

Drillstring data			
Components (from bottom to top)	ID (in)	OD (in)	Length (m)
A475M7838XP	3.750	4.750	7.440
Float Sub	1.750	5.000	0.480
5 1/2" NM Stab	2.880	4.750	2.300
ADOS	2.810	4.750	0.750
2*4-3/4" Pony	2.810	4.750	4.500
Impulse MWD	2.250	4.750	10.720
VPWD	2.250	4.750	4.840
ADN-4	2.250	4.750	7.620
3*3 1/2" NMHWDP	2.060	3.500	28.400
3*3 1/2" HWDP	2.060	3.500	28.080
Hydraulic Jar	2.250	4.750	9.390
5 * 3 1/2" HWDP	2.060	3.500	46.980
Crossever NC38 to XT 34	2.250	4.750	1.130
3 1/2" 15.55 DP	2.600	3.410	189.370
3 1/2" 15.55 DP	2.600	3.410	2578.000

Bit data							
Bit size (in)	Bit type	IADC code	Bit manufacturer	Serial no	Nozzles (n/32") noxn	noxn	TFA (in^2)
5.875	HCM405	M333	Hughes Christensen	7206842	2x10	2x11	0.340

Wellbore info
7" tubing to 2578 m, 5.875" open hole section to 2920 m (6,184" x 5.875" @ 2578 m)

Drilling fluid data							
Type	Base oil Density (s.g.)	Water density (s.g.)	Solids density (s.g.)	Oil/water ratio	Mud density (s.g.)	Reference Temperature (^0C)	Reference pressure (bar)
OBM	0.760	1.000	2.600	83/17	1.680	50.000	1.000
Rheogram readings							
600 RPM	300 RPM	200 RPM	100 RPM	60 RPM	30 RPM	6 RPM	3 RPM
63	35	27	16	11	8	4	3

Table-B.1: Drillstring, wellbore and drilling fluid data

MD (m)	TVD (m)	PPG max values (s.g.)	FPG min values (s.g.)
2578.000	1779.830	1.661	1.890
2678.000	1859.266	1.658	2.030
2678.000	1859.266	1.521	1.921
2747.000	1910.706	1.507	1.874
2747.000	1910.706	1.507	1.874
2750.000	1912.802	1.507	1.872
2750.000	1912.802	1.507	1.872
2824.300	1959.509	1.496	1.861
2824.300	1959.509	1.491	1.866
2847.000	1971.010	1.486	1.856
2847.000	1971.010	1.435	1.829
2861.000	1977.253	1.433	1.816
2861.000	1977.253	1.448	1.748
2920.000	1995.287	1.441	1.746

Table-B.2: Pore/fracture pressure data

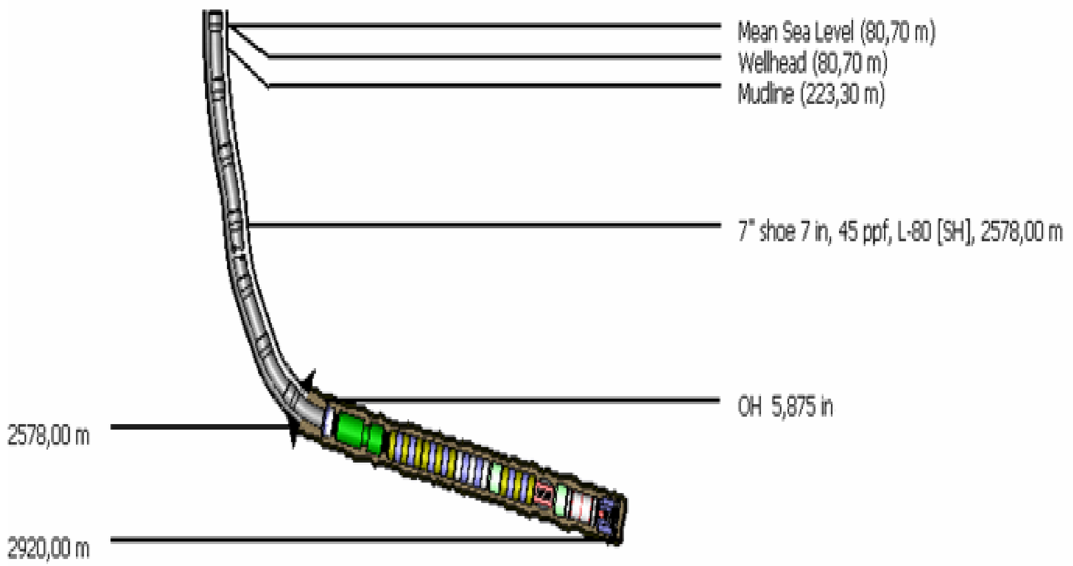

Figure-B.1: Striing and wellbore diagram for well 34/10-B-4B

Appendix-C

Accuracy of Pressure Loss Calculations Given in Section-4

The actual well data given in Appendix-B applies. By use of the pressure loss equations and procedures provided in the Section-4 a spread sheet calculation was performed to calculate pressure losses in different well sections. Result from this computation has been tabulated as follows.

Drillstring Components (from bottom to top)	Annular geometry		Length (m)	ΔP_a (bar)
	OD (in)	ID (in)		
A475M7838XP	5.875	4.750	7.440	0.335
Float Sub	5.875	5.000	0.480	0.041
5 1/2" NM Stab	5.875	4.750	2.300	0.103
ADOS	5.875	4.750	0.750	0.033
2*4-3/4" Pony	5.875	4.750	4.500	0.202
Impulse MWD	5.875	4.750	10.720	0.483
VPWD	5.875	4.750	4.840	0.218
ADN-4	5.875	4.750	7.620	0.343
3*3 1/2" NMHWDP	5.875	3.500	28.400	0.189
3*3 1/2" HWDP	5.875	3.500	28.080	0.187
Hydraulic Jar	5.875	4.750	9.390	0.423
5 * 3 1/2" HWDP	5.875	3.500	46.980	0.314
Crossever NC38 to XT 34	5.875	4.750	1.130	0.050
3 1/2" 15.55 DP	5.875	3.410	189.370	1.155
3 1/2" 15.55 DP	6.184	3.410	2578.000	11.127
			Sum	15.210

Table-C.1: Calculated annular frictional pressure loss

Calculation shows that total pressure drop has been 15 bar as seen in the table above.

Known:

MW	=	1.68 s.g	(effective mud weight during drilling)
TVD	=	1995 m	
ECD	=	1.76 s.g	(actual ECD value from daily drilling report posted in DBR)

Now ECD is calculated using above data and calculated pressure loss for the comparison with actual ECD value.

ECD = MW+P_{AF} /(0.098*TVD) = 1.688+15.210 / (0.098*1995.300) = 1,76 s.g

Note that the result fully matches the actual ECD since digits more than two ignored.

Note: While performing this calculation, we made an assumption that pressure loss reduction due to eccentricity is compensated by pressure loss increase because of tool joints and string rotation. Therefore, these were not included in the calculation above.

Appendix-D

Rheological Models

In the following, the rheological fluid models that have become known during this project will be provided. API, Unified, Robertson-Stiff and Casson Models to be given below have been inspired by Marilyn's work [28]. For further details on these model readers are encouraged to refer this work.

Newtonian Model

A fluid that has a constant viscosity at all shear rates at a constant temperature and pressure is called a Newtonian fluid. The shear stress for a Newtonian fluid is related follows as

$$\tau = \mu\gamma \tag{D.1}$$

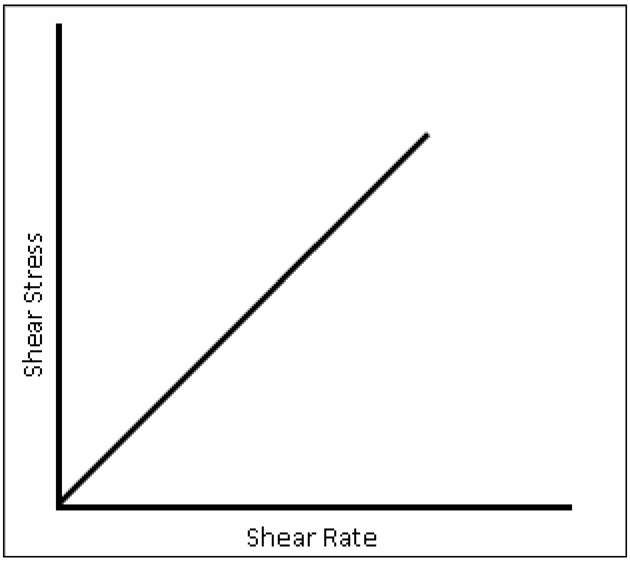

Figure-D.1: Newtonian Fluid Rheogram

Figure-D.1 analytically displays the behaviour of the Eq. (D.1). The seen is direct proportional of shear stress with shear rate. The Newtonian viscosity is the slope of this resultant curve that is straight line. The model serves as a basis from which other fluid models are developed.

Bingham Plastic Model

The Bingham plastic model was the first two-parameter model that earned widespread acceptance in the drilling industry and it is fairly simple to visualize. However, it doesn't accurately represent behaviour of drilling fluids at very low and high shear rates. The mathematical relationship for model is

$$\tau = \tau_y + \mu_p \gamma \tag{D.2}$$

The parameters indexed with *y* and *p* in Eq. (D.2) are yield point and plastic viscosity. They are sometimes called Bingham parameters that can be read from a graph representing the model or calculated by the following equations.

$$\mu_p = R_{600} - R_{300} \tag{D.3a}$$
$$\tau_y = R_{300} - \mu_p \tag{D.3b}$$

The parameters shown on the right hand side of the Eq. (D.3a) are the readings from viscometer at rotational speed of 600 and 300 rpm respectively.

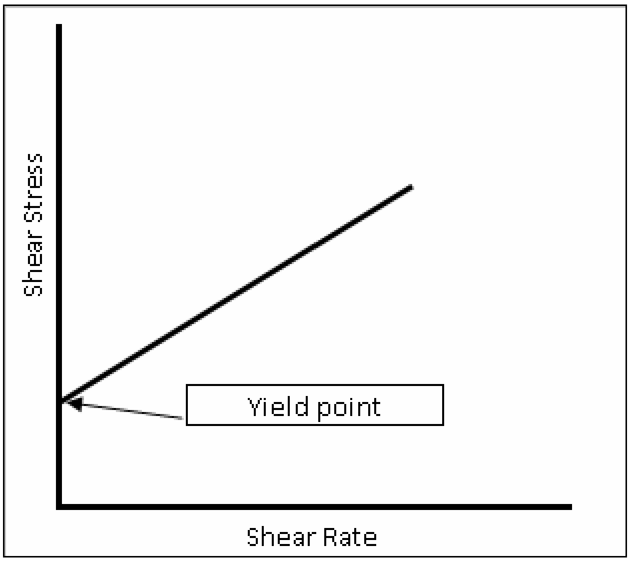

Figure-D.2: Bingham Plastic Fluid Rheogram

Figure-D.2 illustrates the graphical behaviour of the Bingham plastic model. The shear stress at which fluid stays stationary under certain acting force is named the yield point. Some drilling fluids follow this model.

Power Law Model

The Bingham plastic model assumes a linear relationship between shear stress and shear rate. Practical understanding of drilling fluids is that behaviour of these fluids fall between those described by the Newtonian and the Bingham plastic models. This behaviour is classified as pseudo plastic. The relationship between shear stress and rate for pseudo plastic fluids is defined by a model called power law or pseudo plastic, sometimes referred as Ostwald fluid model too. Mathematical expression for this model is

$$\tau = k\gamma^{n} \tag{D.4}$$

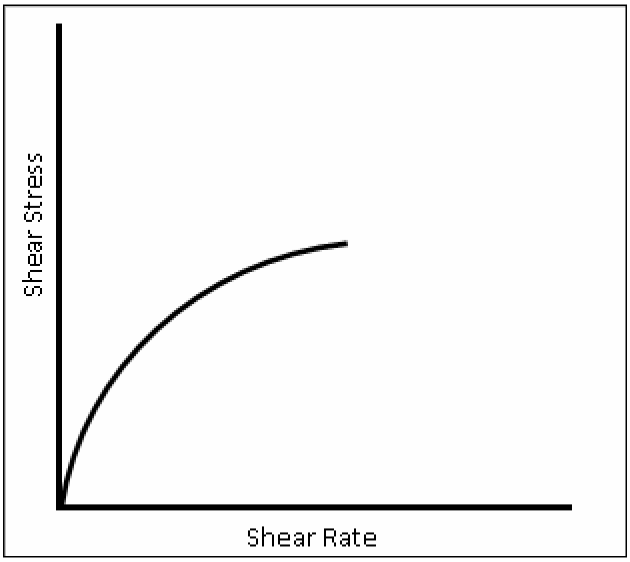

Figure-D.3: Power Law Fluid Rheogram

The curve shown in Figure-D.3 illustrates the power law fluid. As seen from the graph the relation is non-linear. However the Eq. (D.4) can be linearized as

$$\log\tau = \log k + n\log\gamma \tag{D5}$$

The *n* and *k* factors are known as power law constants and are calculated by using

$$n = 3.32\log\left(\frac{R_{600}}{R_{300}}\right) \tag{D.6a}$$

$$k = \frac{510R_{300}}{511^{n}} \tag{D.6b}$$

Drilling fluids are better represented by the power law model than The Bingham plastic model.

API Model (RP 13D)

API RP 13D [41] published in 1995 recommends using the modified power law model to calculate pressure losses in a drilling system. The API model attempts to match shear rates from viscometer readings with shear rates experienced inside drill-pipe and annulus. In drill-pipe, the 600 and 300 rpm readings are used for rheological and hydraulics calculations. In this model *n* and *k* are calculated as

$$n_p = 3.32 \log\left(\frac{R_{600}}{R_{300}}\right) \tag{D.7a}$$

$$k_p = \frac{5.11 R_{600}}{1022^{n_p}} \tag{D.7b}$$

The index *p* in the Eq. (D.7a) and (D.7b) stands for pipe.

In annulus, the 3 and 100 rpm readings are used for rheological and pressure loss calculations. The power law index and consistency factor are computed by

$$n_a = 0.657 \log\left(\frac{R_{100}}{R_3}\right) \tag{D.8a}$$

$$k_a = \frac{5.11 R_{100}}{170.2^{n_a}} \tag{D.8b}$$

API model is a modification of the power law model, in which the power law parameters *n* and *k* are calculated in a different manner for pipe and annulus. In this model *n* and *k* manifest themselves to depend upon the geometry.

Herschel-Bulkley Model

This model is complex than the four models discussed above. The Herschel-Bulkley model is a three parameter model expressed as

$$\tau = \tau_0 + k\gamma^n \tag{D.9a}$$

$$\log(\tau - \tau_0) = \log k + n \log \gamma \tag{D.9b}$$

As observed, the model is the power law model that includes a yield stress τ_o as a third parameter. The yield stress in the Eq. (D.9a) is normally taken as the 3 rpm viscometer reading. There is a more complex expression to compute it as well.

In this model as in the power law the *n* and *k* factors can be calculated from 600 and 300 rpm viscometer readings or graphically. The model is used to describe materials such as concrete, mud, dough, and toothpaste for which a constant viscosity after a critical shear stress is a reasonable assumption when a log-log plot is made. The model can also exhibit a shear-thinning or shear thickening behaviour depending on the value of *n*.

Unified Model

This model is an improved version of a simplified Herschel-Bulkley model. Calculation of the power law constants *n* and *k* for the unified model involves previous determinations of plastic viscosity, yield point and yield stress τ_o expressed in Herschel-Bulkley model. Plastic viscosity and yield point are determined by the Eq. (D.3a &D.3b) respectively. For the Unified model, to estimate yield stress τ_o the following alternative is given: Take low shear yield point (τ_{yL}) as τ_o that is calculated using

$$\tau_{yL} = 1.066(2R_3 - R_6) \tag{D.10}$$

The equations proposed to calculate *n* and *k* for pipe and annular flows are

$$n_p = 3.32\log\left(\frac{2\mu_p + \tau_y}{\mu_p + \tau_y}\right) \tag{D.11a}$$

$$k_p = 1.066\left(\frac{\mu_p + \tau_y}{511^{n_p}}\right) \tag{D.11b}$$

$$n_a = 3.32\log\left(\frac{2\mu_p + \tau_y - \tau_0}{\mu_p + \tau_y - \tau_0}\right) \tag{D.11c}$$

$$k_a = 1.066\left(\frac{\mu_p + \tau_y - \tau_0}{511^{n_a}}\right) \tag{D.11d}$$

The ratio τ_o/τ_y is another important parameter to help characterize fluids rheologically. Some fluids may exhibit plastic and pseudo plastic behaviour. This is important for hole-cleaning and barite sag considerations. As the ratio τ_o/τ_y approaches 1.0 the fluid takes on Bingham plastic behaviour if the ratio τ_o/τ_y approaches 0.0 the fluid behaves more like pseudo plastic (power law) fluid. For example if the ratio is 0.3, clearly the fluid will behave more like the power law fluid.

Robertson-Stiff Model

Robertson-Stiff developed a more general model to describe rheological behaviour of drilling fluids and cement slurries. The equation for the model is

$$\tau = A(\gamma + C)^B \tag{D.12}$$

A and *B* can be considered similar to the parameters *n* and *k* of the power law model. The third parameter *C* is a correction factor to shear rate and the term (γ+*C*) is considered as effective shear rate. Yield stress for the Robertson-Stiff model is given by

$$\tau_0 = AC^B \tag{D.13}$$

When logged the Eq. (D.13) becomes

$$\log \tau = \log A + B \log(\gamma + C) \tag{D.14}$$

The τ is plotted versus (γ+C) on log-log coordinates B is the slope of the resultant curve and A is the intercept where (γ+C) = 1. The C is defined by use of

$$C = \frac{(\gamma_{\min}\gamma_{\max} - \gamma^{*2})}{(2\gamma^* - \gamma_{\min} - \gamma_{\max})} \tag{D.15}$$

Where γ^* is the shear rate value corresponding to the geometric mean of the shear stress τ^* that is calculated by

$$\tau^* = (\tau_{\min}\tau_{\max})^{1/2} \tag{D.16}$$

Robertson-Stiff model is also used in today's drilling industry.

Casson Model

The Casson model is widely used in some industries but rarely in drilling engineering. The model sometimes is used by petroleum engineers in characterization of cement slurry. However, use of it for pressure loss calculations is a difficult and complicated process and rarely attempted. It is a two-parameter model written as

$$\tau = (\tau_y{}^{0.5} + (\mu_p \gamma)^{0.5})^2 \tag{D.17}$$

The point at which Casson curve intercepts shear stress axis varies with ratio of yield point to plastic viscosity. The intercept gives yield point also called Casson yield point and plastic viscosity is the slope of the curve resulting and also named as Casson plastic viscosity.

Appendix-F

Transition Velocity

Transition velocity is a velocity at which flow regime changes from laminar to transition. Some authors have termed this velocity as critic velocity. However, in this study we noticed that it is not necessarily a critic velocity for drilling. For instance, when we say annular critic velocity it is meant a velocity below which hole-cleaning problems start escalating. Annular critic velocity is based on cuttings concentration in annulus rather than flow regime shift. To avoid confusion velocity indicating flow regime change is termed as transition velocity. This velocity for pipe flow is easily obtained from Eq. (4.5) by replacing Reynolds with Eq. (4.6a) and solving it in terms of velocity parameter. Final expression is

$$V_{T(p)} = \left(\frac{k(3470 - 1370n)}{89100\,\rho_f} \right)^{\frac{1}{2-n}} \left(\frac{3 + 1/n}{0.0416 D_p} \right)^{\frac{n}{2-n}} \tag{F.1}$$

Similar equation for annular flow is obtained that is

$$V_{T(a)} = \left(\frac{k(3470 - 1370n)}{109000\,\rho_f} \right)^{\frac{1}{2-n}} \left(\frac{2 + 1/n}{0.0208(D_2 - D_1)} \right)^{\frac{n}{2-n}} \tag{F.2}$$

The annular transition velocity is an important parameter since it will alert driller about annular flow regime. It influences AFP loss, washouts and formations erosion. Turbulent flow results in higher AFP loss, washouts and formations erosion.