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ABSTRACT

This thesis evaluates the possibility for a full mud return, top hole drilling system, applying a concentric dual drill string and an integrated pump. Top holes are usually drilled without mud return, leaving the cuttings on the sea floor. Sea water with barite and other additives are employed as drilling fluid and is released to the sea when used. By employing a dual drill string and a down hole pump to lift the return to top side facilities, full return is enabled. This facilitates the use of high performance mud, which have several advantages, including primary well control before the BOP is set, improved hole stability, elimination of a pilot hole to check for shallow gas influx and extended top hole sections.

Possible solutions to obtain a complete and functioning new system have been analyzed. Based on existing technology and its current limitations, two alternative systems are developed on a conceptual level. The first system includes one integrated return pump, the second employs multiple integrated return pumps. The design base case is set to 1000 meter water depth and 500 meter deep well, of which 100 meter is drilled with a 36" drill bit, and 400 meter is drilled with a 26" drill bit. This base case covers most of the top holes drilled on the Norwegian sector. System pressure estimates are presented, and a mud level regulation solution is developed and analyzed. The mud level regulation system allows the mud level in the well to be controlled to keep the well balanced and stabilized, and to prevent mud discharges to sea floor. The level regulation solution is theoretically proved, and enables reliable regulation of the mud level in the well based on existing technology. Predictions of the system behavior are made, and the limitations of the systems are presented.

The developed systems drilling capacities are analyzed and found not capable of fulfilling the base case requirements, due to the limitations of the selected dual drill pipe. The low flow rate of the pipe limits the ROP, due to high cutting generation with large drill bit diameters. The hydraulic horsepowers at the drill bit nozzles are also too low, due to the lowered available pressure drop, low flow rate, and large drill bit. However, the available pressure drop at the drill bit nozzles are estimated to over 80 bar. It is recommended to employ a larger dual drill pipe, with increased pressure capacity. Then the drilling capacity of the system would be comparable to other full return top hole drilling systems. The systems impact on cost and drilling parameters are discussed and found to be comparable with other innovative solutions for full return top hole drilling.

There are uncertainties of both developed systems. The uncertainties regarding the system employing only one return pump concerns the design limitations of the chosen return pump type, a progressive cavity pump. The uncertainties regarding the multiple return pump system, concerns the system behavior with several return pumps distributed throughout the drill string.

A full return top hole drilling system employing a concentric dual drill string and an integrated pump is found feasible. But due to existing technology limitations, a mud motor is chosen to power the return pump, this demands a drill pipe with a higher capacity than what exists today, to obtain comparable drilling capacity to other top hole drilling systems. The development of an electric conducting dual drill pipe would expand the possibilities much further, and improve the overall drilling capacity of the system.

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ABBREVATIONS:

BOP	Blow out preventer
BHA	Bottom hole assembly
CTS	Cutting Transportation System
DDS	Dual Drill String
DH	Down Hole
DSV	Drill String Valve
HSI	Hydraulic power at drill bit [hp/in^2]
MRL	Mud Return Line
MRR	Mud Recovery without a Riser
MWD	Measure While Drilling
OTC	Office and Tool Container
PCC	Power and Control Container
PGB	Permanent Guide Base
RCD	Rotating control device
RDM	Reelwell Drilling Method
RMR	Riserless mud recovery
ROP	Rate of Penetration
RPM	Rotations per minute
SOM	Suction Module
SPM	Subsea Pump Module
UW	Umbilical Winch
TDA	Top Drive Adapter
TVD	True vertical Depth

Table 1 Abbrevations

NOMENCLATURE

Symbol	Explanation	unit
ΔP_{fA}	Frictional pressure loss in annulus	bar
ΔP_{fIP}	Frictional pressure loss in inner pipe	Bar
ΔP_{fPB}	Frictional pressure loss in pipe body	Bar
ΔP_{fTJ}	Frictional pressure loss in tool joint	Bar
ΔP_{h}	Hydraulic differential pressure	bar
C	Constant value	
C_{SC}	Constant value for calculation of pressure loss in surface connections	
D_{iIP}	Inner diameter of inner pipe	m
D_{iPB}	Inner diameter of outer pipe	m
D_{iTJ}	Inner diameter Tool joints	m
D_{oIP}	Outer diameter of inner pipe	m
D_{oIPC}	Outer diameter of inner pipe connections	m
D_{oPB}	Outer diameter of outer pipe	m
$\frac{dp_f}{dL}$	Pressure gradient gel strength	kPa/m
g	Specific gravity	m/s^2
h_{BHA+M}	Height of motor and BHA	m
h_{DF}	Drill floor height from sea level	m
h_{SW}	Sea water depth	m
h_{W}	TVD well	m
$P_{M\ in}$	Power input to motor	kW
$P_{M\ out}$	Power out from motor	kW
$P_{P\ in}$	Power input to pump	kW
$P_{P\ out}$	Power output from pump	kW
L	Length	m
L_{P}	Length pipe	m
L_{PB}	Length pipe body	m
L_{TJ}	Length tool joint	m
ρ_{C}	Average density Cuttings	Kg/m^3
ρ_{M}	Average density mud in annulus	Kg/m^3
ρ_{P}	Average density mud in return pipe	Kg/m^3
ρ_{SC}	Average density static column	Kg/m^3
ρ_{SW}	Sea water density	Kg/m^3
μ_{P}	Viscosity in inner pipe	cP
μ_{M}	Viscosity in annulus	cP
C_{MN}	Magic number	
P_{BHA}	Pressure loss in BHA	bar
$P_{BHA\ u/s\ nozzles}$	Pressure loss in BHA upstream nozzles	bar

P_{fBH}	Pressure due to friction in bottom hole	Bar
Ph_{HSI}	Hydraulic power at bit per square diameter	HP/in^2
P_{Pout}	Pump outlet pressure	bar
P_{fIP}	Frictional pressure loss in inner pipe	Bar
P_h	Hydraulic pressure	bar
P_{hP}	Hydraulic pressure of pump height	bar
P_{hIP}	Hydraulic pressure in inner pipe	bar
P_{hSC}	Hydraulic pressure of static column	Bar
P_{hSW}	Hydraulic pressure of sea water	Bar
P_M	Pressure drop in motor	Bar
P_{min}	Minimum return pressure to topside	bar
P_P	Pressure increase by pump	bar
P_{TS}	Top side return pressure	bar
P_{fSE}	Pressure drop in surface equipment	bar
Q_{BP}	Flow rate motor bypass	lpm
Q_C	Volume flow rate of cuttings	lpm
$Q_{formation\ fluid}$	Inflow from formation	lpm
Q_M	Flow rate motor	lpm
Q_A	Flow rate annulus	lpm
Q_P	Flow rate return pump	lpm
Q_{slip}	Slip flow through pump	lpm
r_w	Internal radius	in
τ_g	Gel strength	Lb/ft^2
T_{Mout}	Motor output torque	Nm
T_{Pin}	Pump input torque	Nm

Table 2 Nomenclature

1 INTRODUCTION

1.1 Background

Today's top hole drilling is usually accomplished by "drill and dump". This normally implies drilling with a low-cost drilling fluid, which is flushed out of the hole together with drill cuttings to remain on the sea floor. After the top holes are drilled and casings are set and cemented in place, the blow out preventer, BOP and drilling riser is run. A full return drilling system is now established, allowing high performing mud to be employed. The "drill and dump" method has several disadvantages; the environment is affected by the discharges, and the alternative low-cost, low-toxicity drilling fluids may not have the necessary quality for drilling in challenging geological conditions. This leads to higher risks for drilling interruptions and safety hazards. However, there are several innovative drilling systems with full return of drilling fluid, during top hole drilling. One of the most credited systems within this topic is the "Riserless Mud Recovery Technology", RMR, by Enhanced Drilling. IKM's "Mud Recovery without a Riser" system, MRR, has similar characteristics. However, both RMR and MRR have their weaknesses. One weakness is the dependence upon installation and hook-up of several modules topside and subsea.

It is important to further develop top hole drilling to avoid drill and dump, to optimize drilling parameters, to extend casing setting depth, to enable the use of high performing mud during top hole drilling and to study the possibility for a simplified method of full return top hole drilling. Reelwell AS and professor Arnfinn Nergaard desired a master thesis on this subject, evaluation of the possibility for a full return top hole drilling system applying Reelwell's dual drill string together with an integrated pump. The principal layout of the system would look like the following illustration. The illustration shows the dual drill string with supply mud in the annulus, and return mud and cuttings in the inner pipe. A pump lifts the returning fluid to top side facilities, to avoid it flowing out of the well onto the sea floor.

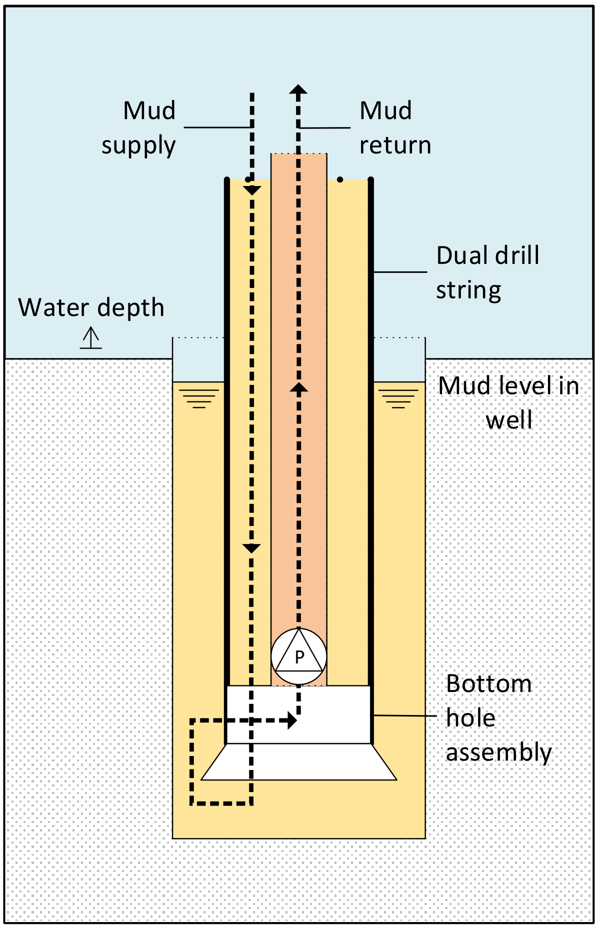


Figure 1 Principal layout new top hole drilling system

1.2 Objective

The objective of the thesis is to evaluate the possibility for a full return top hole drilling system, applying a concentric dual drill string with an integrated pump. Intermediate objectives include to evaluate possible system components, and solutions to obtain a functional system. This includes selection of:

- Pump type
- Pump motor type
- Solution for regulation of the mud level in the well

Practical solutions, for the system parameters above, are to be considered and a new system to be developed.

1.3 Scope of work

To evaluate the possibility of a full return top hole drilling system, as described above, possible solutions to obtain a functioning new system has been analyzed. Based on existing technology and its current limitations, two solutions for a full return top hole drilling system has been further evaluated and analyzed. Technical solutions to complete the system, with regards to avoiding mud emission to the sea floor, has been developed and analyzed. The limitations of the developed systems are discussed, and compared to existing full return top hole drilling systems. The limitations of the developed systems are also evaluated in comparison to other possible solutions for full return top hole drilling systems, based on futuristic technology. Such futuristic technology includes an electrical cabled dual drill string and remotely operated equipment.

Focus on HSE, schedule impact and cost is kept during the development of the new system. The development is kept at a conceptual stage, no testing or detailed design is performed. An overall evaluation on the systems top hole drilling capacity is performed after the system evaluation. Sources of error and uncertainties are discussed.

The thesis will not elaborate upon geological drilling parameters, only brief discussions are made.

1.4 Structure of the thesis

The thesis is divided into nine main chapters:

INTRODUCTION

The thesis background, objective, scope of work and the thesis structure is described to give an introduction of the thesis.

EXISTING TECHNOLOGY

Existing technology and innovative solutions for full return top hole drilling are discussed. Reelwelll AS and their Reelwell Drilling Method is described. Reelwells dual drill string, employed in the thesis is introduced.

DEVELOPMENT OF A NEW FULL RETURN TOP HOLE DRILLING SYSTEM

The first section describes the problem to be solved by the thesis, to clarify the problem to the reader. The second section describes the strategy for system development and the requirements for a new top hole drilling system with full return. The first decisions to obtain a principal system design are made. A short evaluation and selection of solution to enable mud level regulation of the well is presented.

The components of the new system are described, and short analyzes are performed on the dual drill pipe.

ESTIMATION OF PRESSURE DISTRIBUTION WITHIN THE SYSTEMS

The pressure distribution within the systems are estimated to find the limitations of the system, and to be able to select a suitable pump and motor. The estimations are necessary to evaluate a developed principle for the level regulation.

LEVEL REGULATION PRINCIPLE AND MOTOR-PUMP FUNCTIONING

In this chapter, a technological solution to enable the level regulation of the well is described, analyzed and evaluated. The principle reflects on the estimations done in the previous chapter. A discussion of the principle highlights possible errors of the principle.

ANALYSIS OF SYSTEM BEHAVIOUR

This chapter evaluates the behaviors and responses of the systems in various drilling scenarios. The reader gets more familiar with the system functioning.

Uncertainties regarding the design of the system are discussed.

RESULTS

The systems drilling capacity is presented. Pump requirements for the systems are presented. Uncertainties are highlighted.

DISCUSSION

The system design and limitations are discussed.

The possibility for a full return top hole drilling system applying a concentric dual drill string with an integrated pump is discussed with regards to futuristic technology. Learning points are described.

CONCLUSION

The conclusion of the thesis is presented.

2 EXISTING TECHNOLOGY

2.1 Conventional top hole drilling

There are three ways of establishing the top holes: The widest casing, usually 30”, can be drilled and cemented, drilled and hammered down or just hammered into place. It is not uncommon to employ both drilling, or so called “wash down”, together with hammering. The use of different subsea guide frames depends on which vessel the well is drilled from. When drilling from a jack-up or a floating rig it is normal to drill through a template, with several slots, or a satellite well template with only one slot.

Since the accident on West Vanguard at Haltenbanken in 1985 it has become common to drill the top holes without the use of a riser, to prevent uncontrolled gas to enter the rigs drilling area. Shallow gas pockets have been expected to be of a minor size, allowing the gas to disperse with water depths over 100 meters, when drilling an 18 5/8” pilot hole. Drilling the pilot hole is however, avoided with the use of RMR. This saves a day or so in rig time, which is of significant expense.

With expansion of drilling into more environmentally fragile areas, drilling methods are under discussion. Seafloor corals and other ecologically important organisms cause concern with dumping of the top hole cuttings. To enable drilling of top holes without dumping expensive and environmentally damaging high performing drilling fluid, several innovative technologies have been patented, tested and taken in use.

Some areas are prone to top hole instability, shallow gas, “gumbo” sands, weak zones and so on, which may only be safely and economically drilled with high performing mud. An example is Canadian Natural Resources Ltd.’s, CNR’s, drilling in the Northern North Sea, where four out of eight spudded wells were abandoned due to stuck tubing or casing.[1]

2.2 Full return top hole drilling, RMR and MRR

Riserless mud recovery, RMR, by Enhanced Drilling, is, as mentioned earlier, a system allowing full mud return without the use of a riser. RMR was developed by AGR for BP Exploration in 2003 and was evolved from the existing Cutting Transportation System, CTS. CTS is a subsea cutting transportation system, including pumps and hoses, moving the cuttings away from the well template.[1] Since then, RMR has been used to drill over 200 wells all around the world and has several merits from respected companies, such as BP, CNR and INPEX. [1-3]A standard RMR system setup is shown below in Figure 2, Table 3 describes the system components. The figure is taken from an article called "Safe and Efficient Tophole Drilling using Riserless Mud Recovery and Managed Pressure Cementing," written by R. Stave, P. Nordas, B. Fossli, and C. French, on the RMR system. [4]

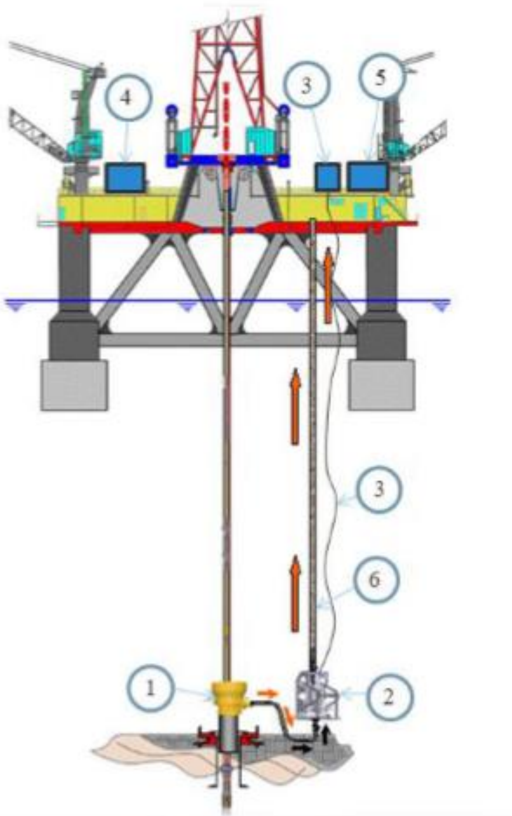


Figure 2 Riserless Mud Recovery System

RMR Key components	
1	Suction Module, SMO
2	Subsea Pump Module, SPM
3	Umbilical and Umbilical Winch, UW
4	Office and Tool Container, OTC
5	Power and Control Container, PCC
6	Mud Return Line, MRL

Table 3 RMR key components

[4]

Enhanced Drilling claims drilling top holes with RMR will enable:

- *"Primary well control before BOP riser is installed*
- *Ability to check for shallow-hazard influx without a pilot hole*
- *Improved hole stability*
- *Deeper surface casing*
- *Fewer casing strings*

- *Top-hole mud log data and cuttings*
- *No cement top-up jobs required*
- *Zero discharge at seabed"*[5]

Safety advantages Enhanced Drilling claims RMR will benefit are:

- *"Safe identification of gas*
- *Better conductor/Xmas tree stability*
- *Mud volume control in surface hole*
- *Fast gain/loss indication*
- *Real-time visual monitoring of the well*
- *No smothering of sea bed by cuttings*
- *Lower risk of undermining well template"*

From Enhanced drilling, RMR, web page[5]

A competitor to RMR, with a similar system is IKM's "Mud Return without a Riser" system, the MRR system. The MRR system has principally the same build-up and functioning as the RMR system. The first application for IKM's MRR system was for Shell on the Malikai project, offshore Sabah, Malaysia in 2014. MRR has also been contracted to AkerBP in 2016, and was to be installed on Transocean Arctic semi-submersible rig early 2017, for drilling on Alvheim.[6, 7]

2.2.1 RMR and MRR Disadvantages

Weaknesses of the RMR and MRR systems are:

- The deployment of equipment through the splash zone has caused delays in operations. One such case was the INPEX drilling through soft Grebe sands in the Browse Basin in 2008.[2]
- Currents and poor visibility may cause delays and problems with the subsea hook-ups of umbilical and the flow lines/hoses.
- The dependence on ROV is also considered a weakness to the two systems.

2.3 Reelwell AS and Reelwell Drilling Method

Reelwell AS is an innovative technology company in Stavanger founded in 2004 by Ola M. Vestavik. The company delivers pioneering technology to the oil and gas drilling industry, and has won the *DNB Innovation Prize* and *ONS Innovator Award* and five *Spotlight on new technology* awards.[8] Two of the awards concerns the "Reelwell Drilling Method", RDM.

RDM, use a Dual Drill String, DDS, with a separate inner pipe leading the return fluid to topside facilities. The DDS connects to the top drive with an adapter, and can be directly connected to any standard bottom hole assembly, BHA. The return drill fluid is led through entrance ports and an inner pipe valve directly above the BHA. The inner pipe valve closes during pipe connections, and isolated of the return pipe from the well. Since the inlet to the inner pipe is set above the BHA, the rest of the annulus, between the DDS and the formation remain in near static conditions. This has several positive effects on drilling parameters such as hole cleaning.[9] Figure 3 and Figure 4 below are taken from a RDM Technology flyer, and shows the RDM system and the Inner Pipe Valve[9]. The Remaining components will be further discussed as they will be a part of the systems developed in the thesis.

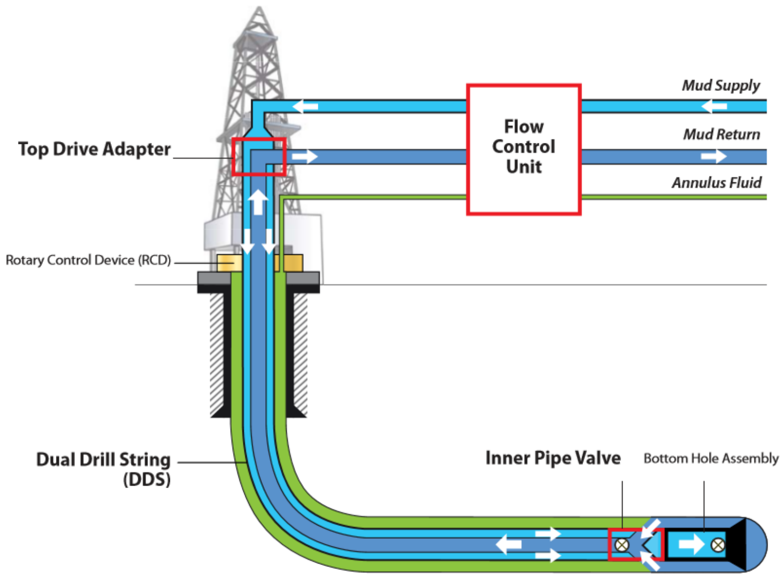


Figure 3 Reelwell Drilling Method

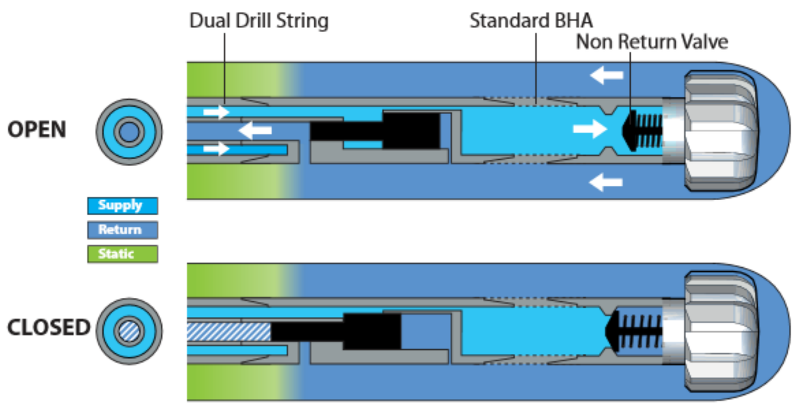


Figure 4 Inner Pipe Valve

3 DEVELOPMENT OF A NEW FULL RETURN TOP HOLE DRILLING SYSTEM

3.1 Principal description of system

The concept of the drilling system is to apply a concentric dual drill string together with an integrated return pump. The dual drill string, DDS, shown below, is taken from a technology flyer on RDM[9]. The DDS has the returning conduit in the inner pipe. The supply fluid flows through the annulus of the dual drill pipe. The dual drill string is handled like a standard drill pipe, and the connections are made by threading the outer pipe, as with a normal drill pipe.

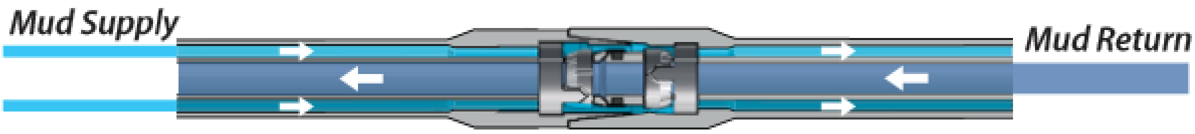


Figure 5 Dual Drill String, Reelwell

The inner pipe allows the return fluid to be lifted by an integrated pump from the bottom of the well, to top side facilities. Without the pump, the mud and cuttings would flow up the well and onto the sea floor, as with conventional top hole drilling. To obtain a full return system, the mud level in the well needs to be controlled. The pump type, motor type and solution for regulating the mud level in the well must be obtained. The principle layout of the system is illustrated below.

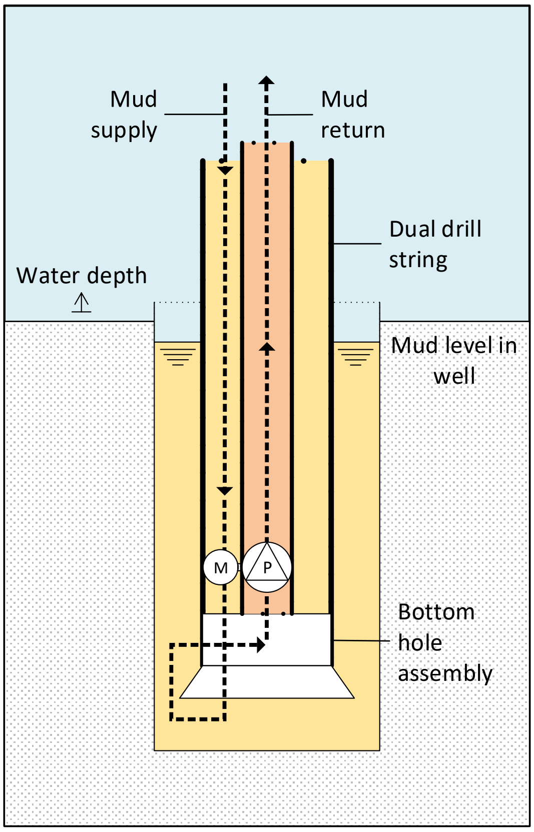


Figure 6 Principal description of system

3.2 Strategy for system development and thesis writing

The strategy for the development of the system has been to evaluate all functional possibilities with regards to the available technological solutions to achieve a complete system. Options with remotely controlled equipment, such as radio-controlled valves, have been excluded.

Some system requirement, set as a base case, are listed in the table below.

System requirements:	
Water depth	1000 meter
Well length(TVD)	100 meter 36”, 400 meter 26”
Not numbered requirements:	
Good safety characteristics with regards to unexpected shallow gas kicks, drilling monitoring and control	
Simple deployment	
Good hole stability	
Good hole cleaning	

Table 4 System requirements

System variables to be set are:

- One or Multiple pumps
- Pump type
- Pump position in the drill string
- Pump power source
- DDS size and capacity
- Control of mud level in the well

After the system has been developed it is analyzed and evaluated. The system design is discussed. The limitations for the developed systems are discussed and compared to limitations expected for a system developed with futuristic technology. Such futuristic technology includes a cabled dual drill string, or a larger dual drill string.

3.3 Evaluation of the Return Pump

One or several return pumps accelerates the returning drilling fluid and cuttings through the inner pipe to top side. There are several demanding characteristics needed for the return pump/s to function as intended. It needs to:

- tolerate solids and abrasive fluids
- have a small diameter to fit inside hole
- have a suitable flow and pressure range

A variety of pumps have been evaluated and the most suitable pump types are discussed in the following sections regarding selection of pump type. Pump flow rate capacity is dictated by the DDS maximum flow range (1200 lpm).

3.3.1 Jet Pump

A jet pump utilizes high pressure energy in a fluid converted into high velocity in a nozzle. A following low pressure zone allows new fluid to be drawn in and accelerated through the pump throat. The idea is to utilize high pressure in the fluid flowing to the well and conducting some of the flow through the jet nozzle. The possibility for utilizing a jet pump was discussed in a report Reelwell made, called the "*Athabasca pump feasibility*" report. In this report Reelwell evaluated the possibility for a downhole, DH, pump to lower the backpressure while production drilling in a reservoir uncappable of detaining pressure from topside to circulate. The requirements for the Athabasca drilling were low compared with the requirements for conventional top hole drilling, with an expected TVD of up to 445 meter. The report stated that to make a DH jet pump work the required pressure from surface would have to be 755 bar, and the necessary return flow would have to be around 2126 liter per minute. Both specifications are higher than the upper limits and the jet pump option is concluded not feasible. [10]

3.3.2 Centrifugal pump

Centrifugal pumps are the most popular pump type in the oil and gas industry. It is a versatile pump type, which can be adapted to many flow and pressure ranges, and can be built to tolerate solids and abrasive fluids. Assembled together with an electrical motor the centrifugal pump could be a viable option, had it not been for the required size to obtain the necessary flow capacity and power demand. The centrifugal pump is disregarded as a viable option due to size.

3.3.3 Turbine pump

Vertical turbine pumps have similar operational functionality to the centrifugal pumps. Impellers or fans thrust the fluid upward by employing high fan velocities. Vertical turbine pumps can be configured with several stages to obtain high pressure and flow capacities, but the solids tolerance is of concern. The turbine pump could be a feasible option if the solids tolerance was high enough. However, due to the uncertainties regarding solids tolerance the turbine pump is disregarded.

3.3.4 Piston pump

It has become increasingly popular to employ piston pumps for fluids containing solids. However, this is not a suitable pump type for DH applications due to the size constriction.

3.3.5 Progressive Cavity Pump

Progressive Cavity pumps, PC pumps, are long and slender and holds the required size. They are tough pumps especially suited for multiphase fluids with high solids contents. PC pumps have a helical working rotor inside a helical stator. The lobe number is always one higher for the stator and cavities between the rotor and stator moves axially as the rotor rotates. The number of stages dictate the maximal pressure capacity of the pump, along with the fit between the stator and rotor. The tighter the fit, the more friction and wear of the pump, but less slip back through the pump, and therefore a higher discharge pressure capacity. The following illustration shows the rotor and stator of a PC pump, the picture is taken from a National Oilwell Varco's web page on PC pumps[11].

Figure 7 Progressive Cavity Pump, Rotor and Stator

PC pumps can be designed to accommodate high flow rates or discharge pressures. However, the pressure range of these pumps become restricted with increasing flow rates.

3.4 Conclusion: Pump selection

The turbine pump and the PC pump are considered to be the best options. Progressive cavity pump has been selected as the superior pump alternative due to its solids tolerance.

3.5 Evaluation of Return Pump Power Source

The return pump power source dictates the overall system design and needs to be one of the first decision to be made.

At first glance, there are several ways to power the Return pump;

- Electricity
- Rotation of drill pipe
- Hydraulic mud motor

3.5.1 Electricity

Employing electricity to power the return pump would simplify regulation of mud level in the well, and open for a range of different pump types and size options. A high performing electric conductor in the DDS would allow high power to be transported to the return pump, leading to good system drilling capacity. However, currently there are no drill pipes with a leading conductor available, nonetheless concentric dual drill strings. Therefore, the option of electricity to power the return pump is disregarded. This would be an interesting option if a DDS with included power cable was invented.

It should be mentioned that Reelwell conducted an experiment in which the DDS was upgraded to function as a conductor to DH instruments. This allowed real-time monitoring without the loss of mud-signals with circulation breaks. The outer and inner pipes where isolated from each other and thereby used as positive and negative source, while drilling with a non-conductive mud.[12] However, the return pump/s would require high voltage and amperage, and the conducted experiment settings is therefore considered not feasible for the powering of the return pump/s.

3.5.2 Rotation of the drill pipe

There are large amounts of energy available in the rotation of the drill pipe. If the pump was driven by rotation of the pipe, it would be easy to control and regulate the pump output or stop and start the pump as desired. However, there are several challenging obstacles in the way:

The bit would need to be powered by a mud motor alone or rotation would need to power both sources. If the rotation was to be used only for the return pump, some kind of restraint to hold back the rotation and generate torque would be necessary, see figure below. With a drill bit mud motor the bit acts as the restraint, grinding against the formation. If the rotation was to be used to power both the bit and the return pump, some kind of energy transfer device would have to be invented to conduct torque from the bit to the pump. But the regulation of the pump would be advanced, as the pump and bit might need independent regulation. Excessive bit wear may be a cause of concern. Vibrations, and other factors would need to be addressed by a damping device. Another cause of concern is that rotation of the pipe is used by drillers in various scenarios, for other reasons than ROP.

This power source is considered to be unpractical, but may be possible with extensive analyses and development. The evaluation of the feasibility of this power source is considered beyond the scope of this thesis.

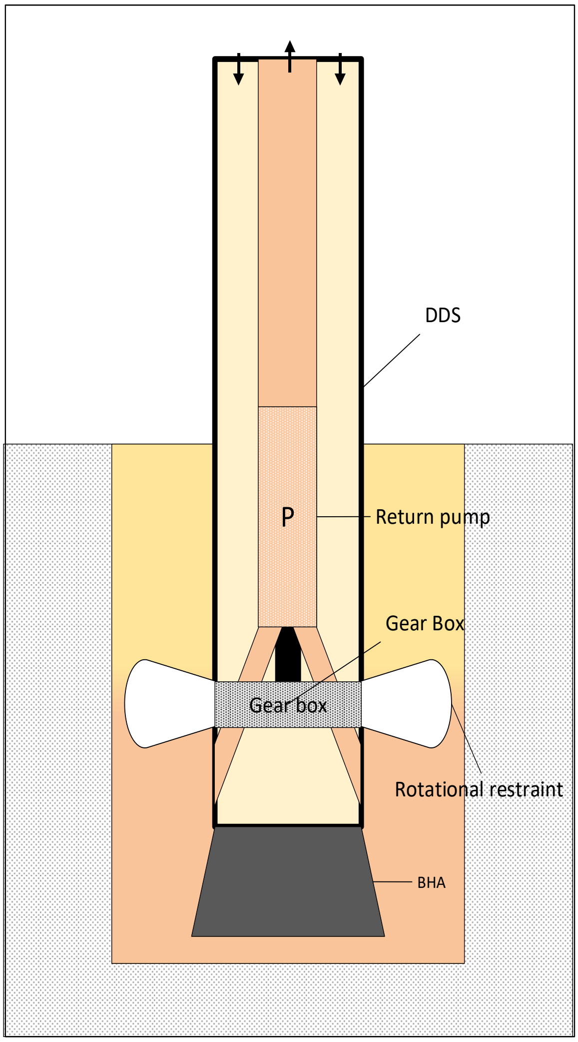


Figure 8 Rotation of drill pipe to power return pump

3.5.3 Hydraulic power – mud motor

DH mud motors are widely employed in petroleum drilling to rotate the drill bit during directional drilling. Therefore, the science of mud motors has advanced in recent years and there is a broad selection of high performing mud motors available on the market. Mud motors come in a variety of sizes and with varying flow and pressure capacities, and mechanical power and torque output. However, the coupling of a mud motor to a return pump would require careful considerations regarding pump and motor flow rates and power and torque generation and absorption. Measures must be taken to enable regulation of the mud level in the well, since both motor and pump power requirements are dependent upon the flow rate.

The employment of mud motors also cause concern with regards to the available hydraulic pressure to be subtracted from the rest of the system. The option of large mud motors to power the bit is eliminated, this could affect the ROP and the possibility for directional drilling of deep top holes. The pressure distribution in the proposed systems are analyzed in detail in later chapters and the mud motor requirements are set as a function of pressure drop, flow rate, and required power output.

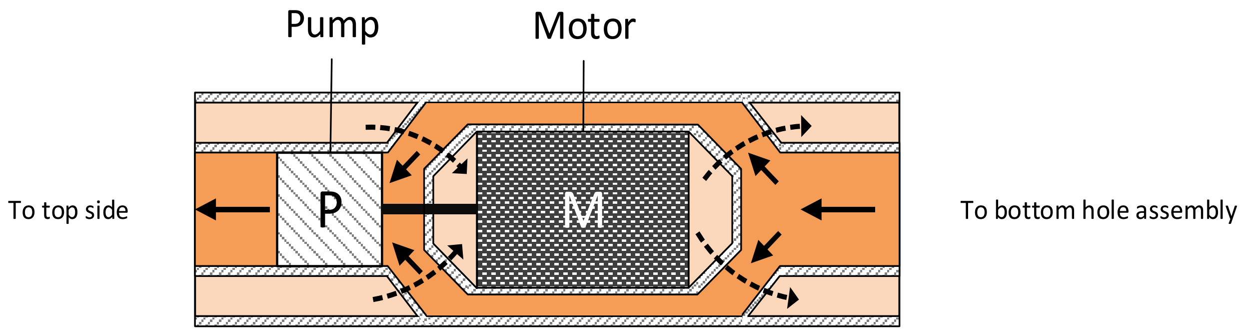


Figure 9 Mud Motor to Power Return Pump

3.6 Discussion and Conclusion: Return pump power source

The best and simplest option appear to be a cabled DDS with an electric motor to power the pump, however, this is not yet an option. The rotation of drill pipe, could strictly operational be a simple solution. But the mechanical solution to enable pump rotation from drill string rotation is complex, and is therefore disregarded.

The only solution available, without extensive new design, is the employment of a mud motor to power the return pump. This may eliminate the possibility to use a mud motor to power the bit in addition to the mud motor powering the return pump. The reason for this is the limited available pressure in the system, due to the employment of a mud motor to power the pump, pressure loss in the pipe, required pressure drop in the drill bit and pressure limitations of the equipment. However, the top holes can be drilled without a mud motor powering the bit. The operational window of the systems is also limited due to high required pressure drop in the motors to power the return pumps.

The pump and motor would have to be designed and paired together with regards to torque, power, flow and differential pressures, and the mud level in the well also needs to be accounted for.

3.7 Evaluation of solutions to control the mud level in the well

The mud level in the well needs to be controlled to keep the drilled hole stabilized and to avoid mud spills onto the sea bed. Since the chosen power source of the return pump is a mud motor, the available solutions to control the mud level in the well becomes more complicated. The return pump is assumed to be directly coupled to the mud motor, thus the motor and the pump will rotate with the same speed. This leaves only the mud supply flow rate to adjust the RPM of the pump and motor, and thereby the return pump flow rate. The circulatory system in the well can be considered to be two independent systems, the supply system, and the return system. The only connection between the two systems is the shaft between the mud motor and the return pump. The flow rates of the supply system and return system are not equal. It is necessary to control the flow rates in both systems, however, this is complicated, because the only way of controlling the return pump, is by adjusting the flow rate of the mud motor.

Two solutions to obtain level regulation is enabled by choosing a pump with a higher displacement, than the motor. Then when the motor and pump rotates, the flow through the motor will always be lower than the flow rate through the pump.

The two solutions to obtain regulation capability:

- Employing a return pump with a higher displacement, than the mud motor, continuously draining the mud level in the well during circulation. And combining the draining with a filling line from topside. See right side of figure below.
- Employing a return pump with a higher displacement, than the mud motor, in combination with a motor bypass conduit. Without the motor bypass conduit, the higher displacement of the return pump would imply continuously drainage of the mud level in the well. With high RPM, the different displacements would cause a larger difference in flow rates through the motor and return pump. This would mean faster mud level decrease rate with high RPM, and lower decrease rate with low RPM. When including a motor bypass conduit to the design, the supply flow rate is increased without affecting the RPM of the motor and return pump. If the bypass flow rate is sized correctly then the supply flow rate can be balanced with the return flow rate, such that well drainage is enabled at high RPM and well fillage is enabled at low RPM. The flow rates are shown in the graph below. A following example is presented to clarify the mud level regulation solution.

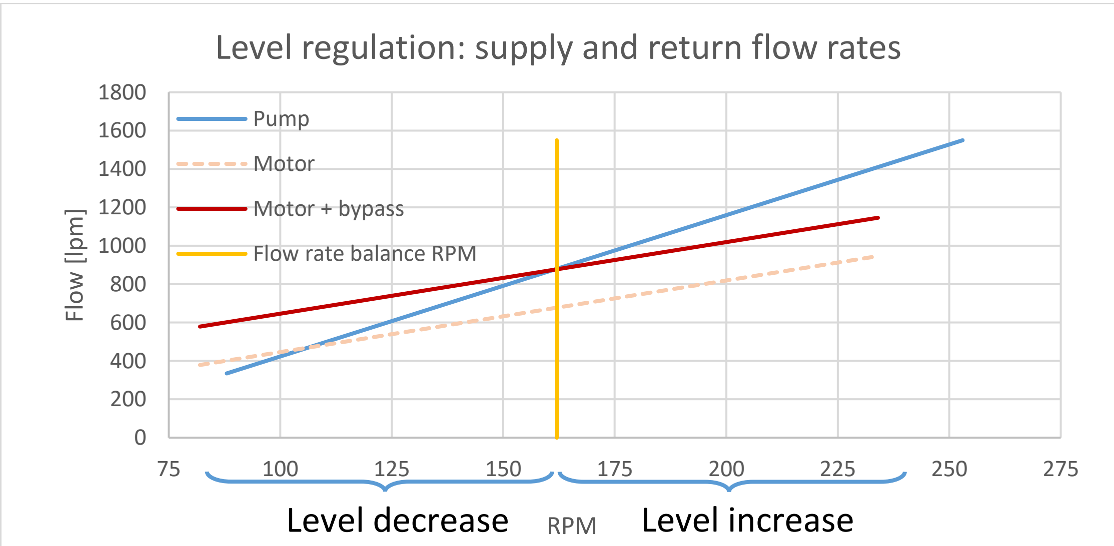


Figure 10 Mud supply flow rate and mud return flow rate

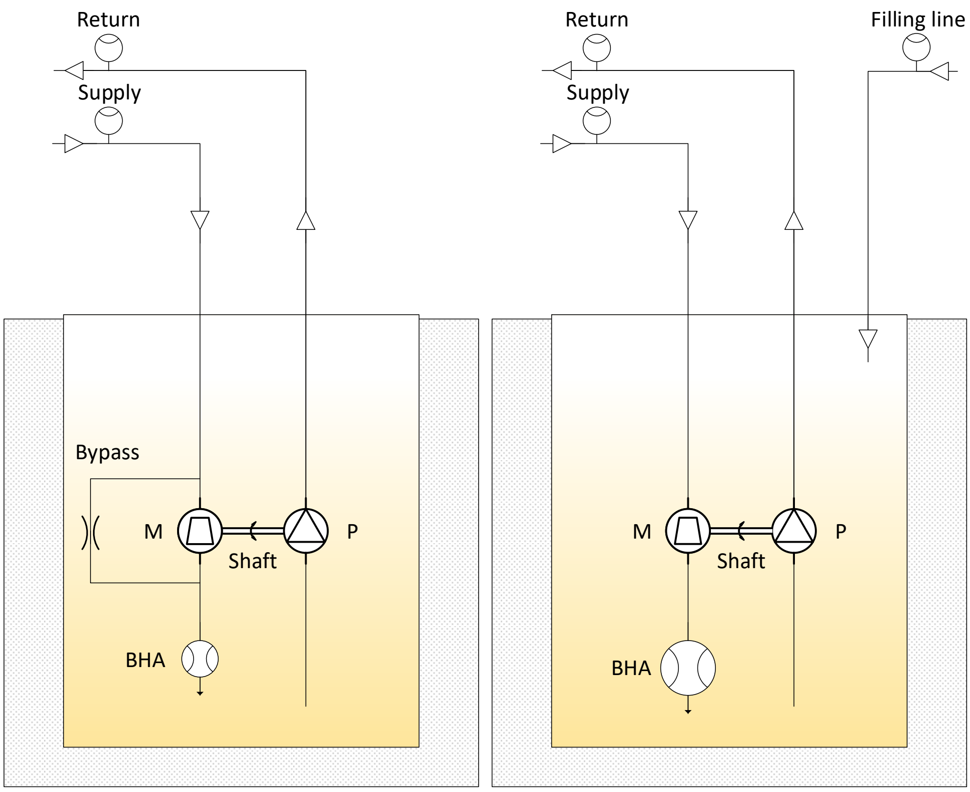


Figure 11 Level Regulation Solution

As explained above, the level regulation principle is made possible by allowing the driller to adjust the flow rate from the topside mud pumps to obtain variable RPM of the mud motors and return pumps. Keeping in mind that the mud motors and return pumps have the same RPM and selecting a return pump with a higher displacement, creates a difference in flow rate into and out of the well. However, with a constant higher flow out of the well than into the well, the well would be drained continuously. Therefore, a bypass flow passing the motor, without entering it, will increase the flow into the well without changing the RPM of the motor and pump. This enables both well drainage at high RPM, and high flow rates, and well filling with low RPM, and low flow rates.

The level control solution with the motor bypass flow is employed.

Example to illustrate level regulation **Off bottom circulation. Stable conditions.**	
Motor and pump speed	150 rpm
Motor displacement per revolution	6 l/rev
Pump displacement	8 l/rev
Bypass flow rate	200 lpm
Motor flow rate	900 lpm
Pump flow rate	1200 lpm

Difference in flow in and out of well	$(1200 - 900 - 200) lpm = 100 lpm$
The mud level in the well is increasing with 100 lpm.	

Table 5 Level regulation principle illustration example

3.8 Presentation of The Single Pump System and The Multiple Pump System

Now that the pump type and the power source for the return pump has been selected and the solution to control the mud level in the well has been set, the overall system design has been set. Two systems have been selected, after careful considerations, for further evaluation. They are called The Single Pump System, and The Multiple Pump System. The two systems are introduced and described in the following sections. A principal illustration, Figure 12, below shows the build-up of the two alternative systems.

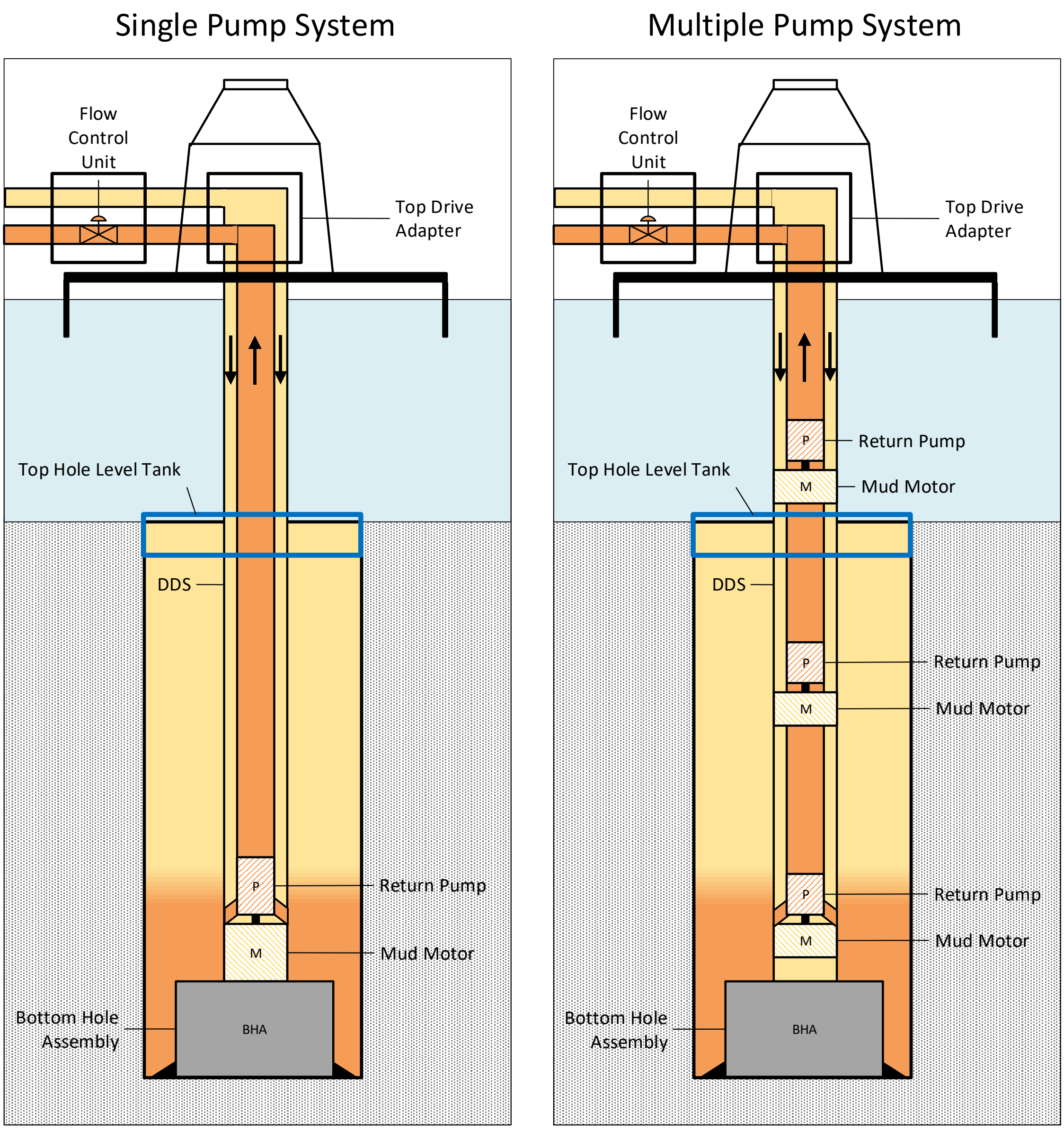


Figure 12 Principle illustration of The Multiple Pump System and The Singe Pump System

The DDS in conjunction with a return pump and return pump motor are the key components in the systems. In the multiple pump systems, one return pump is replaced by a series of pump-motor sets positioned up the DDS. The goal is to reduce the required pressure capacity of the pumps. The number of pump-motor sets in the multiple pump system can be adjusted to the requirements of the top hole, and the desired pressure capacity of the return pumps. The "Top Hole Level Tank", THLT, is also a key component to the systems, permitting monitoring of the mud level in the well. Other equipment necessary to complete the systems are:

- Top drive adapter, TDA
- Drill String Valve, DSV
- Check Valve
- Flow Control Unit, FCU
- Operation Station

These system components will be discussed in the following sections, after the principal system functions have been described.

3.9 The Single Pump System Operational Principle

The return pump lifts the drill fluids from the well to topside facilities to create a full recovery system. As described earlier, the return pump is powered by an associated mud motor.

During circulation, the drill fluid is pumped to the well from the topside mud pumps through the annulus of the DDS. The fluid flows through a mud motor powering the associated return pump, before entering a standard BHA. The remaining overpressure in the pipe is consumed in the bit nozzles. Outside the BHA, in the bottom of the hole, the drill fluid flushes and carries cuttings to the return pump inlet. The mixture is flowing through the return pump inlet channels, to the inner pipe. There, the cuttings and mud are pumped up the to the Top Drive Adapter, TDA. The Flow Control Unit, FCU, including flowmeters, isolation valves and choke valves, is then the only remaining equipment before the standard rig equipment. See Figure 13 on the next page.

After spud in, the mud level in the hole is monitored by transmitters in the Top Hole Level Tank, standing in the top of the hole. Regulation of the mud level in the well is, as briefly described earlier, enabled by using different flow capacities between the mud motor and the return pump, and a bypass flow passing the motor. See Figure 13 below. Keeping in mind that the RPM of the motor and pump are the same, and applying a pump with a higher displacement per revolution than the motor, the flow rate will be constantly higher through the pump, than the motor. With high RPM, the flow through the pump is significantly larger than the flow through the motor, with low RPM the flow rate through the pump is still larger but closer to the flow through the motor. By adding the flow through the bypass, the total flow into the well is higher than out of the well with low RPM. With high RPM, the flow rate out of the well is larger than into the well. The RPM of the motor and pump is varied by adjusting the top side flow rate. The Operation Station, OS, in the drillers cabin allows the driller to operate the mud level by changing the flow rate of the top side mud pumps.

As the Figure 13 below shows, the bypass flow is passing the motor in the center of the rotor of the PC pump. The bypass is small and is equipped with a nozzle to restrict the flow rate through the conduit.

An additional opportunity to regulate the mud level in the well is enabled by a topside choke valve in the return line. Restricting the return flow causes pressure build-up and the slip through the return pump is increased, end the flow rate out of the well is lowered.

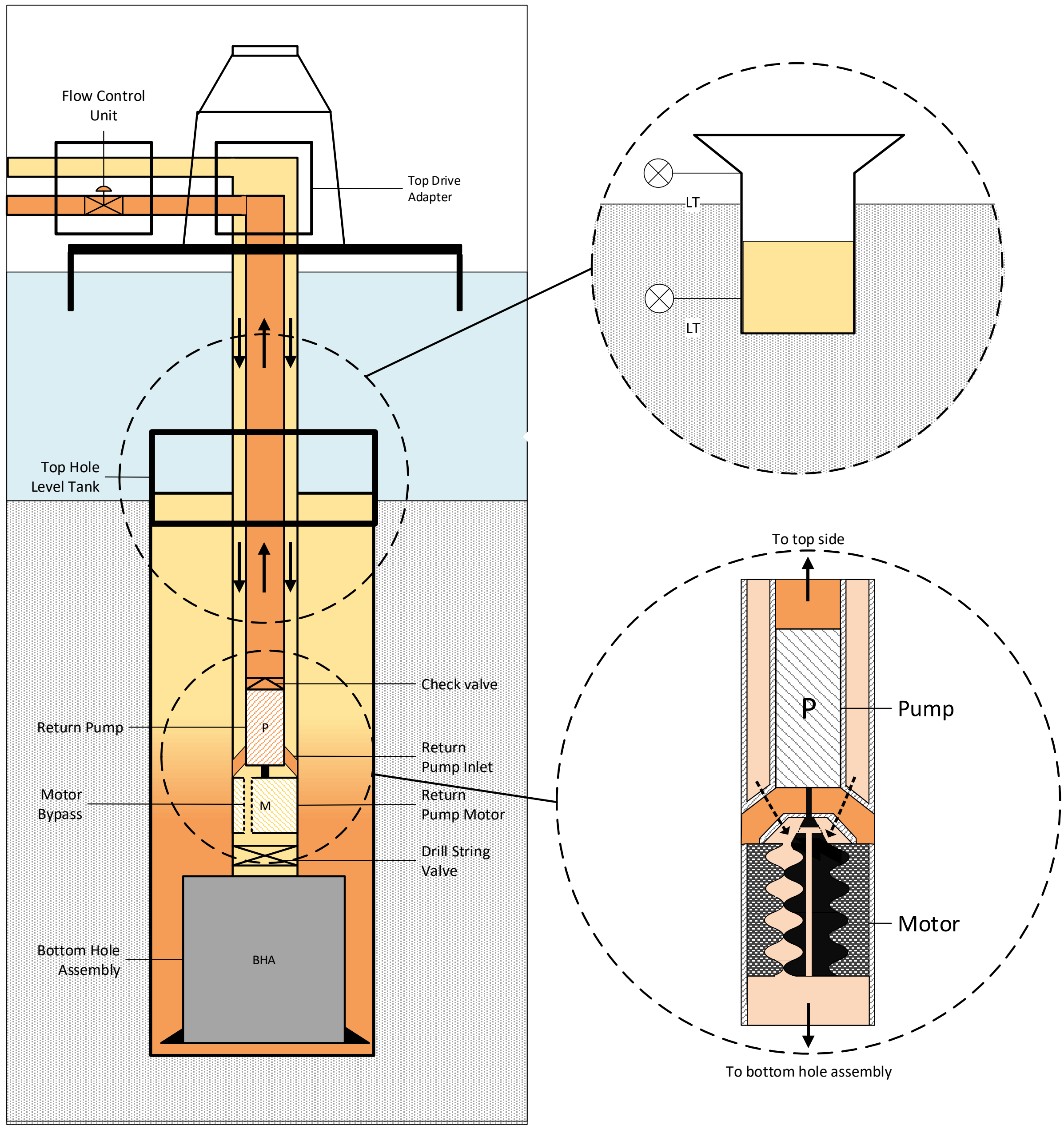


Figure 13 The Single Pump System

3.10 Multiple Pump System Operation Principle

The idea of Multiple Pump System is to employ multiple motor-pump-sets instead of one, thus reducing the required pressure capacity of the motors and pumps. The number of pumps necessary depend on the pressure-capacity of the selected pumps, and the top hole pressure requirement to the return pump. The top hole pressure requirements are among others set by the water depth, well length and desired mud density. The sets are assembled into the drill string with the same distance between each set, to keep the operating conditions within the same range, avoiding extra strain on the pumps. The distance between each set, and the number of sets is adapted to the pressure capacity of the return pumps, with regards to expected hydrostatic and frictional resistance to flow.

A Multiple Pump System with three motor-pump sets are shown in the illustration below.

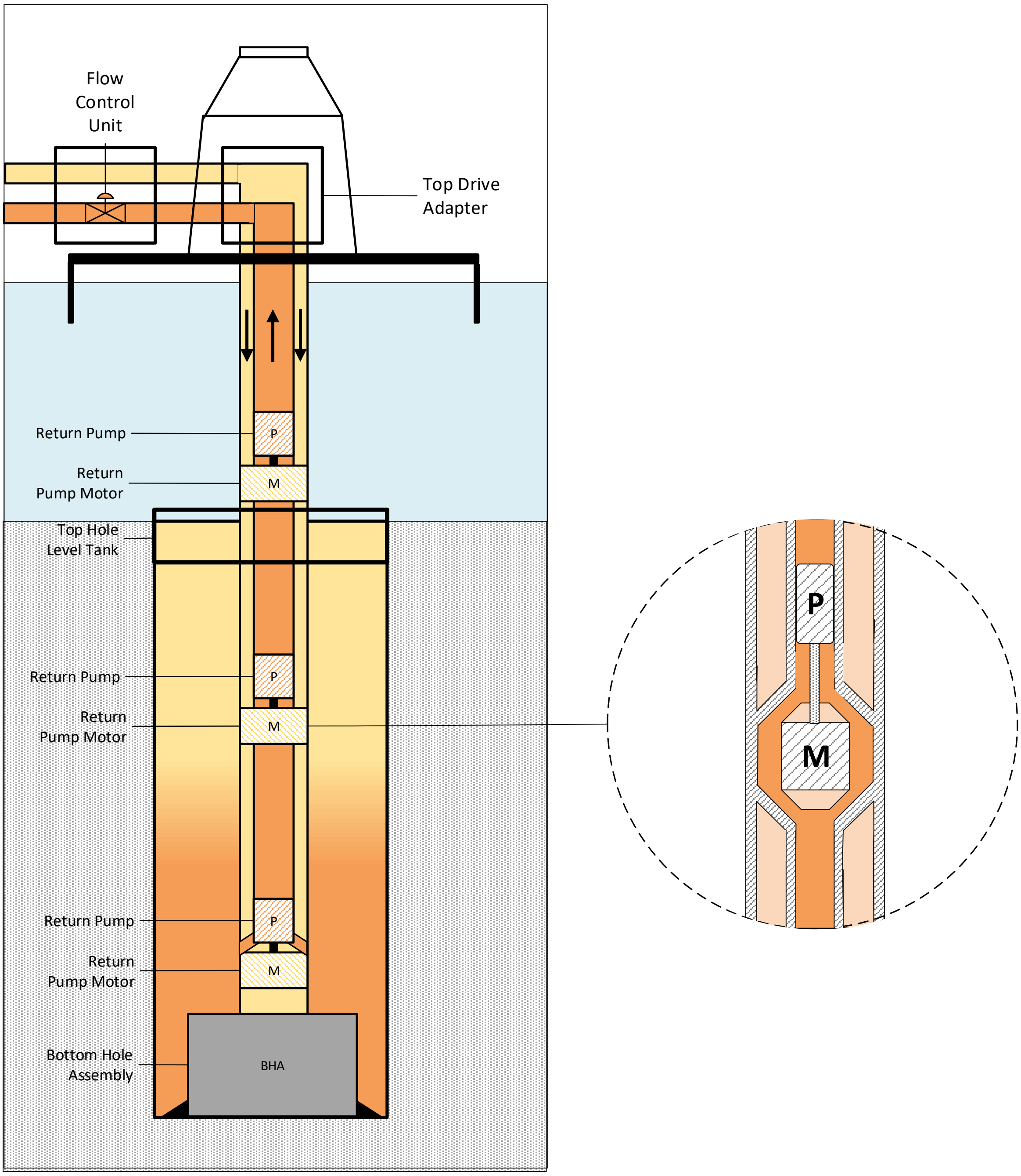


Figure 14 The Multiple Pump System

A cause of concern regarding the series assembly of motors and pumps is the imbalance in motor and pump power distribution. In case of uneven pump differential pressures, would the system balance itself or could small imbalances cause high strain on motors and pumps? This is discussed further in Chapter 6.

3.11 System components

The key components to both systems are presented and evaluated in the following section. Evaluations are made to set the principal system designs.

3.11.1 Top drive adapter

The top drive adapter, a swivel mounted below the top drive, routes the flow to and from the DDS. The top drive adapter is standard RDM equipment, and there is no need for further redesign if a standard DDS is employed. The illustration below shows the TDA, and is taken from a RDM Technology Flyer. [9]

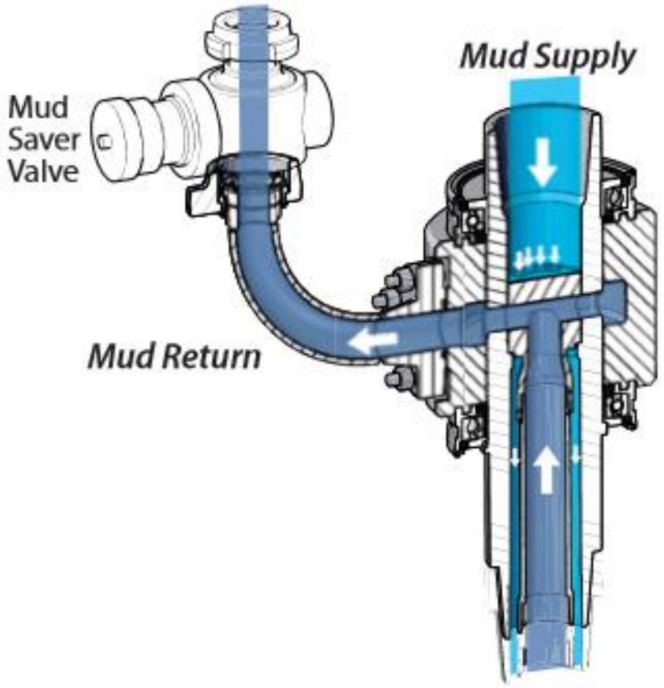


Figure 15 Top Drive Adapter, Reelwell

3.11.2 Dual Drill String

The DDS is a concentric dual drill string. The supply fluid flows in the annulus, and the return in the inner pipe. Reelwell currently has two established DDS editions, the DDS with the highest flow capacity was chosen as a starting point, since the flowrate will be a limiting factor to the rate of penetration, ROP.

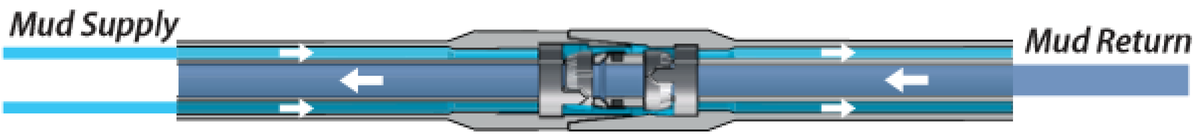


Figure 16 Dual Drill String, Reelwell

The illustration above shows the flow conduits in the DDS. The outer connections are threaded while the inner connections are stab in. The illustration is taken from a RDM Technology Flyer.[9]

Figure 17 Dual Drill String Connections, Reelwell

The two pictures above display the aluminum dual drill pipe connections. The left picture is the box end with the inner pipe pin and sealing element. The right picture shows the pin end, containing the inner pipe box end for the stab in connector. The pictures are copied from an article written by O. M. Vestavik, J. Thorogood, E. Bourdelet, B. Schmalhorst, and J. P. Roed, called "Horizontal Drilling with Dual Channel Drill Pipe. [13]

Some of the pipe dimensions of the dual pipe are included in the table below:

Aluminum Drill Pipe 5 7/8	
Weight	39,4 kg/m
Length	Range 3 (12,2-14 m)
Outer Diameter	190,5 mm
Working pressure	345 bar
Mud temp	-40˚C- 140˚C
Flowrate RDM	0-1200 l/min
Max LCM size	Medium nut plug
Max cutting contents in return mud	5%

Table 6 Aluminum Drill Pipe 57/8

The maximum flow limitation of the DDS is 1200 liter per minute, this is a significantly lower flow than normal for conventional top hole drilling. The flow has impact on ROP with several factors:

- Cutting transportation to surface
- Drill bit nozzle jet horsepower
- Cuttings concentration in return pipe

3.11.2.1 Cutting transportation to surface

During conventional drilling the cuttings needs to be transported all the way up the bore hole. For surface holes the cavity between the drill pipe and the hole walls are significant, and the flow rate must be high to keep the fluid velocity higher than the cuttings slip velocity. In the DDS, the inner pipe diameter is only 2,95 inches. This yields high fluid velocities with small flow rates compared to conventional drilling. The following table illustrates the fluid velocities at variable flow rates with conventional drilling and drilling with DDS. The fluid velocity inside the DDS is high enough to bring the cuttings to surface.

Comparison of return fluid velocity with a 26 inch drill bit at variable flow rates		
Flow rate [lpm]	DDS return fluid velocity **[m/s]**	Annulus return fluid velocity with a 6 5/8” Drill pipe and 26” drill bit [m/s]
400	1,5	0,021
800	3,0	0,042
1200	4,5	0,062
2000	Over maximum flow limit (7,6)	0,104
2400	Over maximum flow limit (9,1)	0,125

Table 7 Comparison of return fluid velocity with a 26" drill bit

The BHA nominal diameter can be increased to increase the velocity of the fluids passing the BHA in the hole, and the length of the BHA is small compared to the rest of the hole. Reelwell has demonstrated effective hole cleaning while drilling a 251 mm diameter hole with average ROP of 30-40 meter per hour. [13] The limited flow rate of the DDS is therefore considered not to be a limiting factor concerning cuttings transportation to surface.

3.11.2.2 Hydraulic power at the bit nozzles

The drilling mud is flushed at the bottom of the hole through nozzles in the bit. The flushing creates turbulence which moves away cuttings from the face of the formation and cleans the drill bit. Without proper flushing, wear of the drill bit may be accelerated and the ROP may be reduced.

The hydraulic power at the bit nozzles, P_{hHSI}, should be in the range 2-5 hp/in^2, according to Drilling Data Handbook.[14] The hydraulic pressure and the power at the bit nozzles relate by the following formula:

$$P_{hHSI} = \frac{P_d Q}{35140 D^2}$$

Where:

- P_{hHSI} is horsepower per square inch [hp/in^2]
- P_d is the differential pressure over the drill bit [kPa]
- Q is the flow rate in liters per minute [lpm]
- $D$is the diameter of the bit [in]

Reelwell has demonstrated good hole cleaning with RDM, without excessive wear of the bit, with $P_{hHSI} = 0{,}85$ during drilling in Abuhadria in Saudi Arabia in 2014.[15] Drilling parameters of interest are listed in the table below:

Parameter	Value	Alternative value
Flow rate	200 gpm	757 lpm
Pressure loss nozzle	856 psi	59 bar
Nozzle hydraulic power	100 HP	
Bit nozzle velocity	327 ft/s	100 m/s
Jet impact force	303 lbf	1348 N

Table 8 Reelwell Drilling Method, Saudi Arabia, Abhadria

Referring to Reelwells earlier results and setting the necessary hydraulic power to $P_{hHSI} = 0{,}85$, the required pressure drop over the bit with variable flow ranges and drill bit diameters are shown in the table below.

Drill bit diameter [in]	Flow [lpm]	Minimum dP over bit [kPa]	Minimum dP over bit [bar]
36	800	48387	484
36	1200	32258	322
36	2000	19355	194
36	2400	16129	161
26	800	25239	252
26	1200	16826	198
26	2000	10095	101
26	2400	8413	84

Table 9 Required differential pressure over drill bit to obtain HSI=0,85

The necessary pressure loss over the drill bit nozzles subtract from the total pressure loss in the system, and will severely affect the pressure distribution in the system. Since mud motors are employed as the return pump power source, the remaining pressure loss available over the bit nozzles is restricted. It is apparent from the table above that an HSI of 1 is unobtainable when drilling a 36” hole with a flow of 1200 lpm.

During the 26” drilling a 198 bar differential pressure is required with 1200 lpm flow. This is also a high value, and will leave a restricted pressure loss to the mud motor due to the maximum working pressure of the DDS to 345 bar. The required pressure drop in the motor to power the return pump is estimated in later sections. When the pressure distribution of the system has been established, the minimum HSI can be used to find the limitations of the systems drilling capacity.

3.11.2.3 Maximum cutting contents in pipe and low flow rate

The drill cutting accumulation rate is a function of the ROP and the diameter of the drill bit. The mud flow rate should be high enough to ensure that the percent of cuttings in the returning fluid is kept within the upper limit of cutting contents in the drilling equipment. The maximum allowed cutting contents in the mud return is thereby a limiting factor on the ROP. The amount of cuttings, liters per 10 cubic meters of mud, is related to the hole size, the rate of penetration and the pump flow rate by the following formula[14]:

$$V_C = \frac{84{,}45 \times D^2 \times ROP}{Q}$$

Where:

- V_C is amount of cuttings [l/10m^3]
- D is the hole size [in]
- ROP is the rate of penetration [m/h]
- Q is the flow rate [lpm]

Setting rate of generated volume of cuttings to 5%, the maximum allowed ROP is shown in the table below.

The ROP for top hole drilling depends on the geological parameters, but normal ranges for ROP of top holes are significantly larger than the maximum ROP limited by the allowed cutting contents. Normal top hole ROP is set to 50-150 feet per hour, 15 - 45 meter per hour.[16]

The maximum cutting contents limit on the DDS is set to avoid a too high backpressure in the return flow while drilling with RDM. However, when utilizing one or multiple DH return pumps, there is no backpressure and the maximum cutting contents limit can be increased significantly. During estimation of the pressure distribution within the systems the estimates are repeated for 0%, 5% and 10% cutting in the return flow. The cutting contents will severely affect the pressure distribution in the system and added hydrostatic and frictional pressures must be considered. The cutting contents limit is assumed to be dictated by the flow restriction in the inner pipe, and the system's ability to pump the cuttings to top side. This implies that the cutting concentration can be high for short durations.

Diameter Drill bit [in]	Flow rate [lpm]	ROP 5% cutting contents [m/hr]	ROP 10% cutting contents [m/hr]	ROP 15% cutting contents [m/hr]	ROP 20% cutting contents [m/hr]
36"	600	2,7	5,5	8,2	11,0
36"	900	4,1	8,2	12,3	16,4
36"	1200	5,5	11,0	16,4	21,9
26"	600	5,3	10,5	15,8	21,0
26"	900	7,9	15,8	23,6	31,5
26"	1200	10,5	21,0	31,5	42,0

Table 10 Maximum ROP as a function of maximum cutting contents limit of DDS

3.11.2.4 Discussion DDS

The limitations caused by the low flow capacity in the DDS is of concern. Limiting the allowed ROP causes the system to be more time-consuming and make drilling of the top holes more expensive than for conventional top hole drilling. The low jet horsepower, HSI, is also a significant source of concern, and may cause excessive wear of the drill bit or reduce the ROP. The bit nozzles should be selected with regards to the expected nozzle pressure drop. Excessive wear of the drill bit may result in schedule delays due to low ROP and required change of drill bit.

3.11.2.5 Conclusion DDS

For further analyses and evaluation, the standard aluminum DDS is employed. This allows the use of a frictional pressure loss estimation sheet, supplied by Reelwell. The limitations of the system are expected to suffer from this choice, and a possible conclusion on the feasibility of a full return top hole drilling system could be to develop a larger DDS.

3.11.3 Drill string valve

The purpose of a DSV during conventional drilling is to prevent fluids to flow back into the drill pipe during mud pump stops. During managed pressured drilling or drill and dump the DSV needs to operate differently. Is needs to stop the flow from the pipe entering the well. This is to prevent heavy mud inside the drill pipe from u-tubing. During drilling with the DDS, the DSV needs to stop the flow during pump shut down to prevent the heavy mud inside the annulus from u-tubing. As long as the mud inside the annulus is heavier than sea water, the hydrostatic pressure inside the annulus will push mud up the well and out onto the sea floor with circulation stops.

DSVs have been developed and used in dual-gradient systems, it is therefore assumed to be a standard component to be fitted to the BHA. However, the required pressure range for the valve to crack open might need to be expanded. It is assumed that a DSV will easily be adapted to suitable pressure and flow ranges and further discussion of the DSV is disregarded.

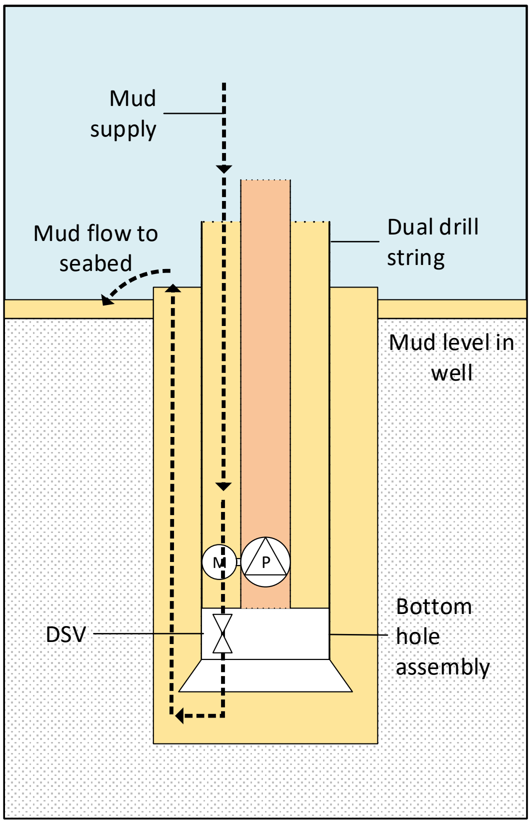


Figure 18 Drill String Valve

3.11.4 Check valve

A check valve prohibits drainage of the inner pipe of the DDS during circulation stops. The pressure drop in the valve should be kept at a minimum and the valve should have a low crack open pressure. The valve must tolerate cuttings and sediments settling on the discharge side during circulation stops. The design of the check valve is a simple task and further evaluation is disregarded. If further detail analysis of the systems is conducted, it may be concluded that this check valve is superfluous due to tight pump configurations and resistance to rotate due to no flow through motors. The water depth to be drilled in also affects the necessity of a check valve. The shallower water depth, the less difference in hydrostatic pressure is exerted on the pump.

3.11.5 Top Hole Level Tank

The Top Hole Level Tank, THLT, is not a standard component, and needs to be developed. Detail design of the THLT is not included in the thesis, but an evaluation on the component follows.

The THLT has two main objectives:

- Monitoring of the mud level in the hole
- Accommodate for level disturbances during circulation start-up, tripping and unplanned activities

To able monitoring of the mud level in the well, transmitters are incorporated into the THLT. A live feed camera could also be an option. The transmitters and camera could be powered by batteries, eliminating the need for extra cabled wires, other than the standard guide wires. The signals transmitting level and optional video could communicate with the rig by wireless communication.

The other purpose of the tank is to be a buffer for displaced mud volumes during tripping operations or other unplanned drilling operations. An example of operation could be to maximize the mud level in the THLT before tripping out of the hole. This way the mud level would stay within the desired limits when the pipe volume is extracted from the well.

The idea is to deploy the THLT instead of or onto a spud base, drilling template, or temporary or permanent guide base, or whichever drilling guide base is employed. If necessary the THLT could consist of two separate components, one employed for the spud drilling and the other for continued drilling of for example the 26" hole, after the first hole has been drilled. The THLT needs to be run into the sea floor to receive and contain the mud level.

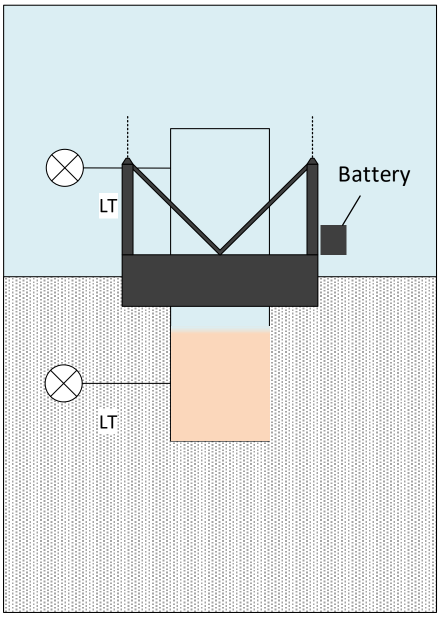


Figure 19 Top Hole Level Tank

3.11.6 Flow Control Unit with choke

During RDM a Flow control unit, FCU is standard equipment. During drilling with the RDM the FCU enables the DDS to be utilized as a conventional DS, and allows the mud pumps to run continuously. Essentially it consists of two parallel trains with isolation and choke valves and a crossover and flowmeter for the returning fluid. An illustration of the standard FCU follows, the picture is taken from a RDM Technology Flyer[9].

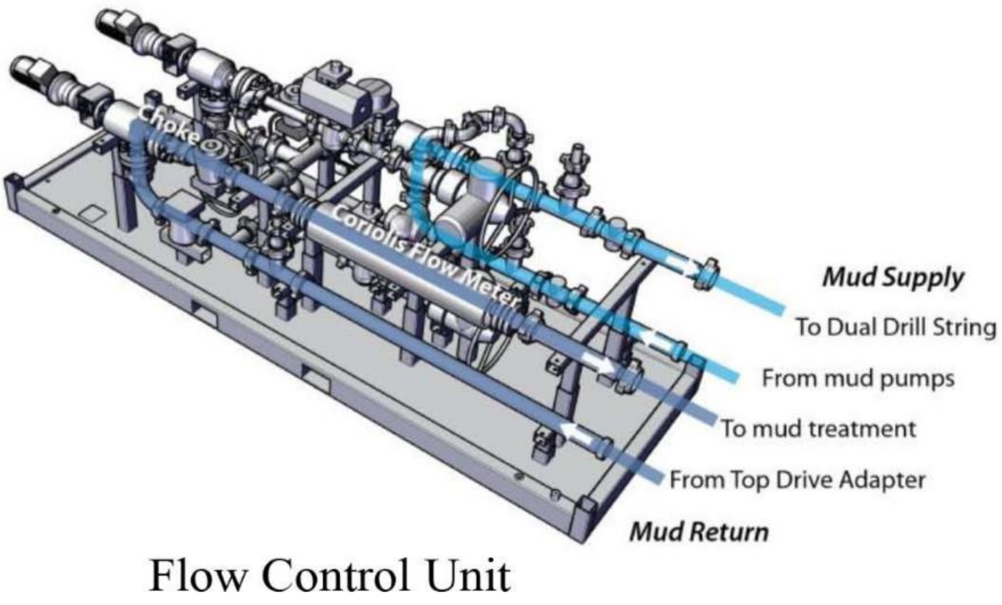


Figure 20 Flow Control Unit, Reelwell

3.11.7 Operation station

The Operation Station, OS, allows the driller to monitor the mud level in the hole and other drilling parameters. During DDS drilling it is of standard operational procedure to set up an OS, at the drillers cabin. The operation station is basically a screen displaying drilling parameters such as flow and pressure, and should be modified to also contain the hole mud level. The operational procedures should enquire level alarms and may propose mud pump flow rates to regulate the level within desired ranges.

The modification of the existing screen and software is considered to be a straight forward task and further discussion on the theme is disregarded.

4 ESTIMATION OF SYSTEM PRESSURE DISTRIBUTION

4.1 Description of analyses

Estimations of the pressure distribution of the systems are conducted to find the systems limitations with regards to the drilling capacity. This means the water depth, well length, density and cutting contents the system can operate with. The pressure estimations also enable the selection of appropriate return pumps and motors.

The frictional pressure losses in the DDS and surface equipment, and the hydraulic pressures in the DDS and in the well, are key calculations. The pressure distribution over the drill bit, motor and pump has been estimated. The Required discharge pressure from the return pump dictates the mud motors pressure drop, and is calculated by selecting an efficiency to 0,72 for both the pump and motor. A calculation sheet supplied by Reelwell has been used to obtain frictional pressure losses in the DDS. An example calculation is conducted to illustrate the total pressure distribution calculation method.

Pressure peaks during start-up of circulation, due to thixotropy, has also been grossly estimated.

The pressure distribution calculation has been repeated many times over to obtain a range of drilling scenarios. The repeated estimations are conducted in a spread sheet, allowing easy computation to repeat the estimation. The selected parameters for the drilling scenarios are listed in the table below. Key results are discussed in the Results chapter.

Variables	Selected values
Drill bit [in]	26
Water depth [m]	100, 250, 500, 750, 1000, 1250, 1500
Well length [m]	500, 750, 1000, 1250, 1500
Cutting contents [%]	0, 5, 10
Density [kg/m^3]	1100, 1250, 1400
Flow [lpm]	600, 900, 1200

Table 11 Selected drilling scenario parameters

Assumptions made with regards to the pressure estimation are listed in Table 12 below.

Assumptions:		
Density of static column	$\rho_{SC} = \rho_M$	It is assumed that the cuttings will follow the mud flow into the return conduit well. Cuttings in the static column are expected to descend to the inlet. Cuttings too large for the inlet is assumed to be grinded against

		the hole walls and other cuttings, until they can pass through the inlet. Therefore, the density of the static column is set at the same value as the employed mud.
Density of drill fluid	$\rho_M = C$ $\rho_P = C$ $\rho_{SC} = C$	The variation of density profile of the fluid column in the annulus and inner pipe is neglected, and average values have been employed during all calculations. This is also the recommended practice in API 13 D.[17]
Density of cuttings	$\rho_C = 2400\ kg/m^3$	
Viscosity	Set as a function of the mud weight: $\mu = 2 * \frac{\rho_M}{119{,}84}$	The plastic viscosity as set at the high side of expected value. The formula is extracted from Murchison Drilling schools' book: "Rule-of-thumb for the man on the rig", page 2:4.[18] The viscosity is dependent upon the solids concentration and shape, it is set at the high side due to expected high fraction of solids in return line.
Well angle		It is assumed that the well is vertical with negligible angle offsets.
Influx from formation	$Q_{formation\ fluid} = 0$	Influx from the well is set to 0 during calculations.
Pump-motor-coupling	$P_{Mout} = P_{Pin}$ $T_{Pin} = T_{Pin}$	The losses in the coupling between the motor and pump is assumed to be a part of the motor's and pump's efficiency.
Motor bypass flow	$Q_{bypass} = C$	The motor bypass value is set to a constant value. However, the flow will be a product of the fluid parameters, bypass nozzle size and configuration and the pressure differential over the nozzle.
Return Pump discharge pressure	$P_{Pump\ outlet}$ $= P_{required\ to\ flow}$	It is assumed that the pump discharge pressure will adjust according to the downstream resistance to flow, plus an additional choke value of 5 bar. However, during calculation of the pressure distribution of the systems, the pump discharge pressure is set to 320 bar.
Frictional Pressure loss		The spreadsheet supplied by Reelwell is assumed to be relatively exact all though cuttings contents, size and shape is ignored. The calculations are treated as

		estimates and are not meant to be precise, but to highlight the limitations and possibilities of the systems.
Influence of pipe rotation on hydraulics		The influence of pipe rotation on hydraulics during circulation is neglected.
Pressure loss surface equipment	$P_{SE} = 10\ bar$	The total pressure loss in surface equipment is set to 10 bar. This is considered to be a high value, but appropriate to take into account extra equipment such as the FCU and TDA.
Pressure loss bottom hole	$P_{fBH} = 3\ bar$	3 bars have been added to the BH pressure to account for resistance to flow, from the bottom to the return pump inlet.
Pressure loss in BHA upstream drill bit nozzles	$P_{BHA\ u/s\ nozzles} = 5bar$	The pressure drop in the BHA upstream the nozzles is assumed to be 5 bar. This assumption is made to obtain a more reliable value for the hydraulic horsepower at the bit.
Pressure loss DSV		The pressure loss in the DSV is accounted for in the separate 5 bar assumption in the BHA.
Pressure drop in drill bit nozzles		The pressure drop in the drill bit nozzles is assumed to be the available pressure drop after the other pressure losses have been subtracted. It is assumed that the nozzles in the drill bit is selected and adjusted to the expected pressure drop available to the drill bit, and to not limit the pressure drop in the mud motor by exerting a too high flow restriction.
Topside mud pumps discharge pressure [Bar]	$P_1 = 320$	The maximum working pressure of the DDS is 345 bar, the input pressure is limited to 320 bar to avoid over pressurizing the equipment due to unexpected pressure increases.
Top side return pressure	$P_{TS} = +5\ bar$	5 bars have been added to the estimation of the systems resistance to flow to gain a topside pressure high enough to ensure flow to shale shakers.

Table 12 Assumptions made with regards to Estimation of pressure distribution

4.2 Elevation of Return Pump

It is possible, strictly mechanically, to elevate the return pump and its inlet conduits up the drill string. However, this might not be a good solution. The position of the return pump and inlet conduits are discussed briefly in the following section, and a decision on the position in the drill string is made.

Due to the low flow rates of the DDS, the return inlet channel should be placed as low as possible to obtain the best possible hole cleaning and drilling conditions. The cutting transportation is optimized by having a higher fluid velocity than the cutting slip rate, and since the cross section of the inner pipe is smaller than that of the hole, the velocity will be much higher inside the DDS. The length of fluid flow in the open hole will also cause friction around the drill pipe and hole walls and restrictive forces on drilling progression are undesired.

If the inlet conduits were elevated there would also be larger discharges during the spud in of a new well. If the inlet conduits were elevated, the supply mud would be discharged to the THLT but large amounts could flow over onto the sea floor, before the inlet channels became submerged into the mud level in the THLT.

It is decided to have the return inlet conduits as low as possible, placed above the motor.

The pump elevation is a discussion on the positioning of the lowest return pump in the drill string. At first glance, it is possible to elevate the pump up the drill string away from the down hole return inlet conduits. However, several factors can be sources of errors with an elevated pump:

- Elevation of the pump would require the pump to work in suction. Due to lower friction and hydrostatic pressure, the easiest flow direction during circulation is up the well, and not through the narrow return inlet. Inflow of gas volumes are to be expected during drilling, and may cause the pump to lose its suction. To quickly gain suction again, the return pump should be placed as close to the liquids as possible, implying a lower most position.
- Cuttings content cause another concern. During circulation stops the cutting contents in the fluid may be somewhat suspended by thixotropy in the drilling mud, but it is to be expected that the cutting will fall down the return pipe. This may lead to blocked return inlet channels. With a return pump placed directly above the inlets the solids will residue on the pump top and be forced aggressively with pump start. The force created by suction of an elevated pump is incomparable.
- It is expected that the wear of the return pump will increase with higher start-up suction pressures.

Based on the above arguments it is concluded to place the return pump in the Single Pump System and the lowest return pump in the Multiple Pump System, as low as possible. To avoid several cross-overs the motor is placed below the pump. See figure below.

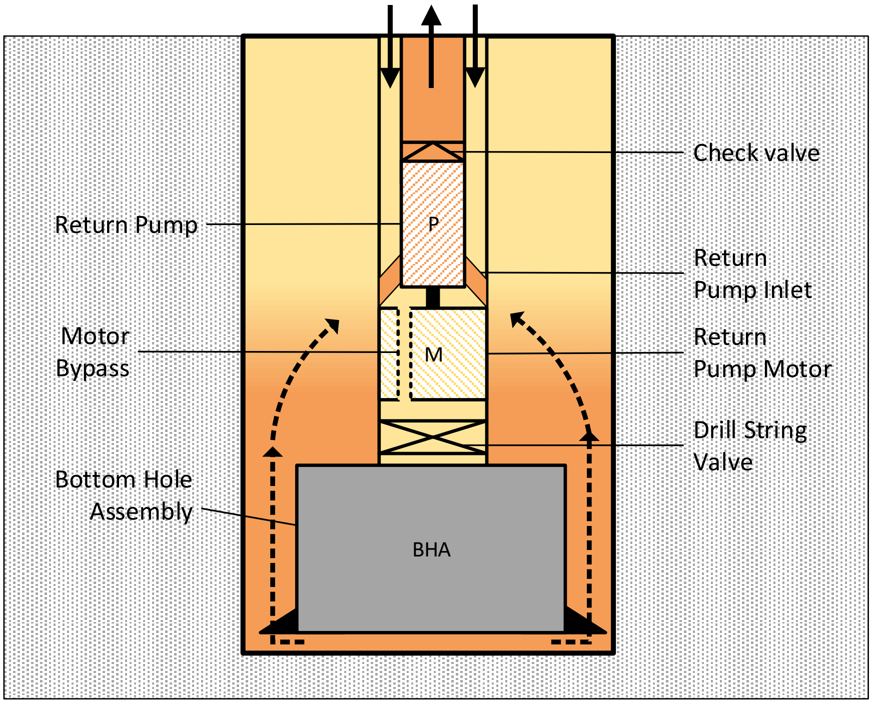


Figure 21 Elevation of return pump and inlet conduits

4.3 Hydrostatic pressure and lift capacity

The hydrostatic pressure inside the return pipe depends on the height of the fluid column and its density. The volume percent of cuttings and its specific gravity severely affects the density and is included in the calculations. For compressible fluids, the density will vary significantly with temperature and pressure, however, as stated in Table 12, the average density is assumed to be precise enough. This is also the recommended practice in *API 13 D: Rheology and Hydraulics of Oil-well Fluids, Section 7.2.4.1* .[17]

The density inside the drill pipe may be significantly higher than the surrounding seawater, yielding a higher hydrostatic pressure inside the drill pipe at seafloor level. At bottom hole level the density difference of the static fluid column and the return pipe fluid also increase the difference in hydrostatic pressure over the return pump. With the assumption of a density in the static column to be the same as the supply mud, and no inflow into well, the difference in the return pipe fluid density is a function of cutting contents. The return pump needs to overcome the difference in hydrostatic pressure in addition to frictional resistance to continue flow. The hydrostatic pressure to be overcome by the return pump can be calculated by the following formula:

$$\Delta P_h = g/100000[(h_{DF} + h_{SW} + h_W - h_{BHA+M})\times\rho_P - h_{SW}\rho_{sw} - h_W\rho_M]$$

Where:

- ΔP_h is the delta hydrostatic pressure over the return pump [bar]
- g is the specific gravity [m/s^2]
- h_{DF} is the height to drill floor [m]
- h_{SW} is the sea water depth [m]
- h_W is the well depth [m]
- h_{BHA+M} is the height of the BHA and the mud motor [m]
- ρ_P is the density of the returning fluid (supply mud and cuttings) [kg/m^3]
- ρ_{sw} is the density of sea water [kg/m^3]
- ρ_M is the density of the supply mud [kg/m^3]

For the Multiple Pump System, the hydrostatic pressure difference over the lowest pump is divided into how many motor-pump sets the system is configurated with. Each pump should be able to lift the returning fluid to the next pump.

4.4 Frictional Pressure Loss Calculation Method

Pressure loss in a flowing fluid is caused by friction between the fluid particles and between the fluid particles and the adjacent surroundings. Parameters affecting the pressure loss are density, viscosity, flow rate, flow regime, conduit geometry and rheological parameters. The return pump needs to overcome the frictional pressure loss to obtain flow. The frictional pressure loss also impacts the available pressure loss to the mud motor and the drill bit, and should be calculated for the whole system.

The frictional pressure loss calculation is divided into three separate segments;

- Inner pipe frictional pressure loss
- Annulus frictional pressure loss
- Surface-connection pressure loss

4.4.1 Inner pipe frictional pressure loss

As mentioned earlier, Reelwell has supplied a spreadsheet for the calculation of frictional pressure loss in the chosen DDS. The formula in the spread sheet is basically the pressure loss equations for a Bingham fluid in turbulent flow. The calculation of the frictional pressure loss within the inner pipe is conducted with following formula:

$$\Delta P_{fIP} = \frac{L_P \times \rho_P^{0,8} \times Q_P^{1,8} \times {\mu_P}^{0,2}}{C_{MN} \times D_{iIP}^{4,8} \times 100}$$

Where:

- ΔP_{fP} is the frictional pressure loss in the inner pipe [bar]
- L_P is the length of the inner pipe [m]
- ρ_P is the density of the fluids in the inner pipe [kg/m^3]
- $Q_P$is the flow rate through the inner pipe [lpm]
- μ_P is the viscosity in the inner pipe [cP]
- C_{MN} is a constant, magic number, []
- D_{iIP} is the inner pipe diameter [in]

4.4.2 Annulus frictional pressure loss

The frictional pressure loss through the annulus of the DDS is conducted in two separate calculations;

- Pipe body
- Tooljoints

The formulas are:

$$\Delta P_{fTJ} = \frac{L_{TJ} \times \rho_M^{0,8} \times Q_A^{1,8} \times {\mu_M}^{0,2}}{C_{MN} \times 100 \big(D_{iTJ} + D_{oIP}\big)^{1,8} \big(D_{iTJ} - D_{oIPC}\big)^3}$$

$$\Delta P_{fPB} = \frac{L_{PB} \times \rho_M^{0,8} \times Q_A^{1,8} \times {\mu_M}^{0,2}}{C_{MN} \times 100 (D_{iPB} + D_{oPB})^{1,8} (D_{iPB} - D_{oIP})^3}$$

And the total frictional pressure loss in the annulus is:

$$\Delta P_{fA} = \Delta P_{fTJ} + \Delta P_{fPB}$$

Where:

- ΔP_{fTJ} is the frictional pressure loss in the tool joints [bar]
- L_{TJ} is the total length of tool joints [m]
- $\rho_M$is the density og the supply mud [kg/m^3]
- $Q_A$is the flow rate through the annulus [lpm]
- ${\mu_M}^{0,2}$is the viscosity of the supply fluid [cP]
- C_{MN} is a constant []
- D_{iTJ} is the inner diameter of the tool joint [in]
- D_{oIP} is the outer diameter of the inner pipe [in]

- D_{oIPC} is the outer diameter of the inner pipe connections [in]
- ΔP_{fPB} if the frictional pressure loss in the pipe body part of the annulus [bar]
- L_{PB} is the total length of pipe body [m]
- D_{iPB} is the inner diameter of the pipe body [in]
- D_{oPB} is the outer diameter of the pipe body [in]
- D_{oIP} is the outer diameter of the inner pipe [in]

4.4.3 Surface-connection pressure loss

The surface connection pressure loss for conventional drilling can be calculated by the following formula, extracted from API 13D, section 7.3[17]:

$$P_{SC} = C_{SC} * \rho_S * \frac{\left(\frac{Q}{100}\right)^{1,86}}{100}$$

Where:

- P_{SC} is the frictional pressure loss in the surface connections [psi]
- C_{SC} is a constant found in API 13D []
- ρ_S is the density of the supply mud [ppg]
- Q is the flow rate [gpm]

C_{SC} is set according to a table presented in API 13D, section 7.3, and is set to 1.0. The surface connection pressure loss for conventional drilling is conducted in Table 14 below.

	SI	**API**
$\boldsymbol{Q}$	$1200\ lpm$	$317\ gpm$
$\boldsymbol{\rho_S}$	$\frac{1400kg}{m^3}$	$11,68\ ppg$
$\boldsymbol{C_{SC}}$	1,0	1,0
$\boldsymbol{P_{SC}}$	$6,89\ bar$	$100\ psi$

Table 13 Surface connection pressure loss

However, the calculation above does not take the FCU and TDA into consideration. Therefore, a value of 10 bar has been selected to accommodate for pressure loss in the additional equipment, and the abbreviation is changed to P_{SE}, Surface Equipment.

4.5 Starting circulation and thixotropy

To keep cuttings in suspension during circulation stops most drilling muds are thixotropic. This means that the fluid exhibits liquid behavior during flow, but hardens when at rest and acts more like a gel. The desirable level of thixotropic behavior varies with cutting parameters and well design, and sets the gel strength. The frictional pressure loss calculations do not include the pressure needed to overcome the gel strength created by the thixotropy, and is only applicable after the mud has been sheared for some time. In conventional drilling the pressure required to break the gel strength may be a good deal higher than the pressure required keep the circulation at the desired flow rate.[19]. However, there are significant differences between the flow conduits in conventional drilling and in the DDS. One of the most important difference is that the velocity of the return flow is independent of the hole diameter and drill pipe diameter. As mentioned earlier, although the flow rate in the DDS is restricted, the velocity of the returning fluid is increased due to a small cross section in the inner pipe. Increasing the velocity of the returning fluid means shortening the time to elevate the cuttings or circulate the cuttings out of the pipe before pipe connection stops. This may lower the necessary gel strength. The small cross section and high fluid velocity also affects the necessary pump pressure to gain flow when gel strength has occurred. The pressure gradient necessary to break the gel and start circulation can be calculated if the gel strength is known:

$$\frac{dp_f}{dL} = \frac{2\tau_g}{r_w}$$

Where:

- $\tau_g = gel\ strength$ [lb/100ft^2]
- $r_w = internal\ radius$ [in]
- $\frac{dp_f}{dL} = Pressure\ gradient$ [psi/ft]

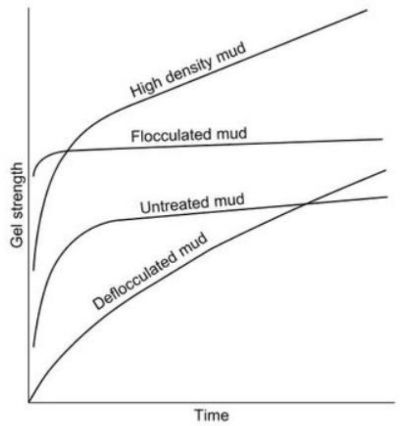
Equation is taken from “Applied Drilling Engineering”[19]

The equation shows that the pressure gradient increases with decreasing radius. This means that compared to conventional drilling, this system will exhibit higher gel strengths. It should be verified that the return pump pressure capacity is high enough to break the gel strength and hydrostatic pressure, to be able to start circulation.

To lower the startup pressure there exists several simple operational procedures for conventional drilling. Rotating and reciprocating the drill pipe before starting the pumps at low flow rates may be included in such procedures. The hope is to create movement in the drill fluid and break some of the bonds in the gel, and therefore needing less pressure to establish circulation.[20] These operational procedures may also be applicable with the proposed system, and perhaps with increased effect for the returning fluid, due to the small diameter of the inner pie. Friction between the wall and drill fluid at the wall will cause flow, but the friction between fluid particles will limit this flow to a shallow layer of fluid near the moving pipe wall. However, with decreasing diameter the flowing fluid layer will increase proportionality.

Estimating the pressure to break the gel strength in the return fluid pipe, is also necessary to avoid pumping liquid out of the hole due to high resistance in the return pipe during start of circulation. However, the systems response during circulation start-up is hard to predict. And the maximum allowable gel strength may be lower than simple calculations will predict.

API Recommended Practice 13D, section 7.4.12.3 Breaking circulation (special case) states that the: "*Laminar-flow pressure-loss equation in 7.4.12.2 can be used to estimate the minimum pressure required to break circulation by substituting the fluid's 10-min gel strength G_{10m} for the yield stress τ_y under no-flow conditions. The G_{10m} value could represent an average for the entire well, or preferably be adjusted for temperature and pressure, if data are available.*"[17]



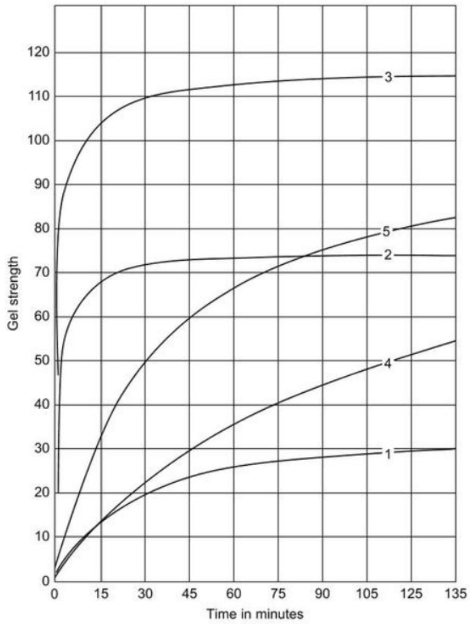


Figure 22 Gel strength in Californian bentonites

Figure 23 Gel strength in Californian bentonites

The above figures are taken from The Advanced Drilling and well Technoly book written by B. S. Aadnøy and shows the relation between gel strength and time for Californian bentonites[21]. The variations of gel strength over time between different mud types are wide, making the prediction of long term gel strength challenging.

Setting the value for the 10-minute gel strength to G_{10m} = 50lbf/100ft^2 yields

$$P_f \approx L * \frac{\tau_g}{300 d_i} = 4920 * \frac{50}{300 * 2{,}95} = 278\, psi = 19\, bar$$

Where:

- P_f is the pressure required to break the gel strength [psi]
- L is the length of the fluid column [ft]
- τ_g is the gel strength [lb/100ft^2]
- d_i is the inner diameter of the pipe [in]

The return pump needs to be able to build a gel breaking pressure, of perhaps 19bar, in addition to overcome the added hydrostatic pressure inside the returning conduit. In addition, comes the inertia and friction forces in the mud motors and return pumps.

4.6 Single Pump System Pressure Distribution

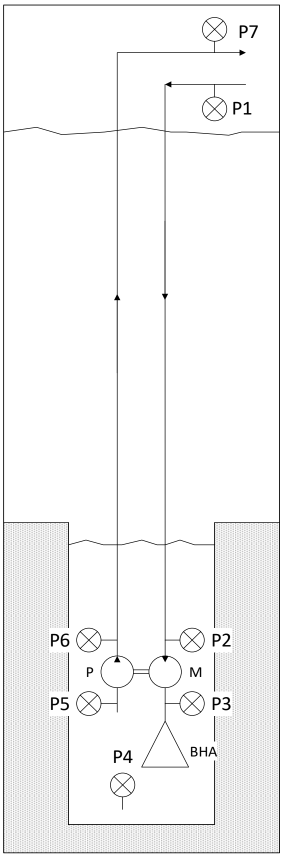
The discharge pressure from the top side mud pumps is dependent on the systems resistance to flow. During flow, the resistance is a function of:

- The hydrostatic pressure difference over the drill bit nozzles
- The frictional pressure loss in the annulus of the DDS and in the surface equipment
- The flow restriction in the mud motor
- The flow restriction in the drill bit nozzles

The pressure loss in the drill bit nozzles varies with flow, drill bit and nozzle size, viscosity and drill bit nozzle configuration. The selection of the drill bit design is considered to be beyond the scope of this thesis, but it is assumed that the drill bit applied will be in accordance with the expected pressure loss over the drill bit. If the drill bit nozzles exert too much restraint, this will lead to a lower available pressure drop to the motors. This will in turn restrict the operational window of the system. The inlet pressure is set to a high value, 320 bar, to gain as much differential pressure over the drill bit as possible.

The pressure distribution is, as mentioned earlier, estimated for a series of water depths, well depths, flow ranges and densities. This section will show how the pressures within the system has been estimated. It should be stated that the actual pressures will wary from the estimated, due to motor and pump torque and power balancing with variable flow rates and backpressures.

To illustrate the pressure distribution, Figure 24 below shows the points, *P1* to *P7,* referred to during the explanation of the single pump system. The pressure line between P4 and P3 is stippled. This is to show that the difference between P3 and P4 not is calculated, but a product of the available pressure drop after the mud motor has taken what it needs to power the pump.



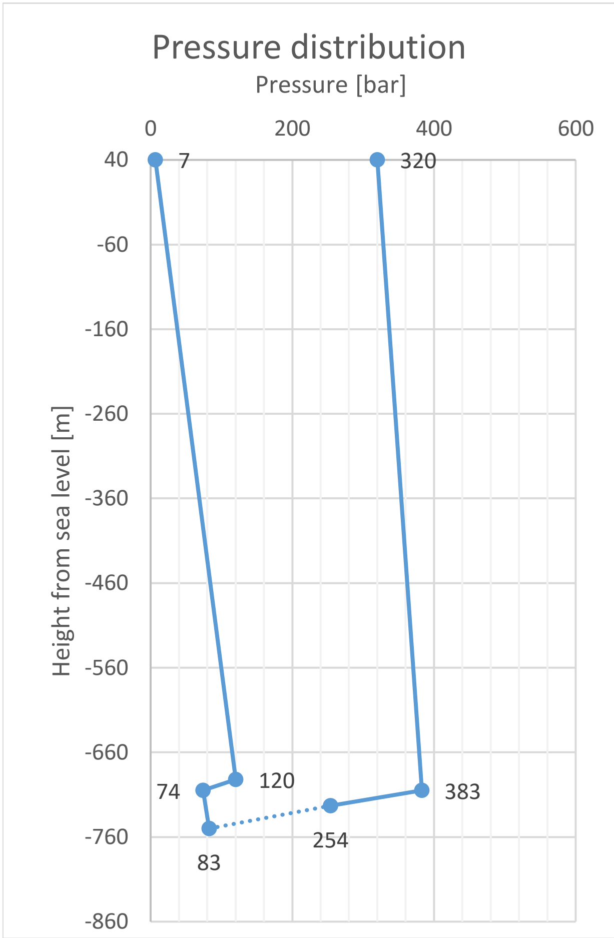


Figure 24 Pressure distribution Single Pump System

Figure 25 Pressure Distribution Single Pump System

The following explanation is only valid during stable circulation. The pressure distribution during connections breaks, start-up and ramp-up will differ from the pressure distribution during steady flow.

The top side pressure upstream the well, at *P1*, is set by the mud pump discharge pressure and the annulus, motor and bit flow resistance. The pressure will from this point on decrease due to frictional losses in the surface equipment and annulus of the DDS, and increase due to added hydrostatic pressure down the pipe.

P2, the pressure upstream the DH mud motor is a function of *P1* and the vertical length from drill floor to the mud motor and the frictional pressure loss in the surface equipment and the annulus. *P2* has been calculated by the following formula:

$$P2 = P1 - P_{fA} - 0{,}5P_{fSE} + P_{hA} = P1 - P_{fA} - 0{,}5P_{fSE} + g\times\rho_M\times\frac{h_{DF} + h_{SW} + h_W - h_{BHA} - h_M}{100000}$$

Where:

- P_{fA} is the frictional pressure loss in annulus [bar]
- P_{fSE} is the frictional pressure loss in surface equipment [bar]
- P_{hA} is the hydraulic pressure [bar]
- g is the specific gravity [m/s^2]
- $\rho_M$is the density of the supply mud [kg/m^3]
- h_{DF} is the height to drill floor from sea level [m]
- h_{BHA} is the height of the BHS [m]
- h_M is the motor height [m]
- h_{SW} is the water deoth [m]
- h_W is the well depth

The pressure downstream the mud motor, *P3*, is a function of the necessary motor pressure drop to obtain the required power input to the return pump and the pump/motor efficiency. *P3,* has been calculated with the following formula:

$$P3 = P2 - P_M + P_{hM} = P2 - P_M + g\times\rho_M\times\frac{h_M}{100000}$$

Where:

- P_M is the pressure drop in the mud motor
- P_{hM} is the hydraulic pressure gained in the mud motor [bar]

The bottom hole pressure, *P4*, is mainly only dependent upon the hydrostatic pressure exerted by the static mud column and the sea water column above. 3 bars have been added to account for frictional pressure resistance, of the flow from the bottom to the return pump inlet. The formula which has been employed is:

$$P4 = P_{hSC} + P_{hBHA+M} + P_{hSW} + P_{fBHA+M} = \frac{g[\rho_{SC}(h_W - h_{BHA} - h_M) + \rho_P(h_{BHA} + h_M) + \rho_{SW}h_{SW}]}{100000} + 3$$

Where:

- P_{hSC} is the hydrostatic pressure of the static column [bar]
- P_{hBHA+M} is the hydrostatic pressure of the fluid outside of the BHA and motor [bar]
- P_{hSW} is the hydrostatic pressure of the sea water column [bar]
- P_{fBHA+M} is the frictional pressure loss outside og the BHA and motor [bar]
- ρ_{SC} is the density of the static column [kg/m^3]
- ρ_P is the density of the returning fluid [kg/m^3]

The return pump inlet pressure, P5, is basically the same as the bottom hole pressure, with the additional 3 bars and the hydrostatic column of the BHA and motor subtracted. The formula employed is presented below.

$$P5 = P_{hSC} + P_{hSW} = \frac{g[\rho_{SC}(h_W - h_{BHA} - h_M) + \rho_{SW} h_{SW}]}{100000}$$

The necessary discharge pressure of the return pump, *P6*, is dependent on the difference in hydrostatic pressure between the inner pipe and the pump inlet, and the frictional losses in the surface connections and added topside equipment and in the inner pipe. An additional 5 bars have been set as the minimum required top side pressure downstream the FCU to ensure sufficient pressure to flow to shale shakers or other cutting removal equipment. The necessary pressure at *P6* has been calculated by the following formula:

$$P6 = P5 + P_P$$

Where:

- P_P is the pressure increase by the return pump [bar]

P7, the outlet pressure downstream the FCU is the return pump discharge pressure with pipe and surface connection pressure losses subtracted. It is calculated by the following formula:

$$P7 = P6 - P_{hIP} - P_{fIP} - 0{,}5P_{fSE}$$
$$= P6 - \frac{g\rho_P(h_{SW} + h_W + h_{DF} - h_{BHA} - h_M - h_P)}{100000} - P_{fIP} - 0{,}5P_{fSE}$$

Where:

- P_{hIP} is the hydrostatic pressure in the inner pipe [bar]
- P_{fIP} is the frictional pressure loss in the inner pipe [bar]
- h_P is the height of the return pump [m]

The pump pressure delivery is set by the design of the pump. However, as long as the pressure capacity is larger than the required pump pressure delivery, the discharge pressure from the pump should be adjusted to the necessary pressure to keep the flow rate steady.

$$P_P = P_{fIP} + P_{fSE} + P_{hP} + P_{hIP} + P_{min} - P_{hSC} - P_{hSW} + P_{min}$$
$$= \frac{g}{100000}[\rho_P(h_{DF} + h_{SW} + h_W - h_{BHA} - h_M) - \rho_{SC}(h_W - h_{BHA} - h_M) - \rho_{SW}h_{SW}]$$
$$+ P_{fIP} + P_{fSE} + P_{min}$$

Where:

- P_{hP} is the hydraulic pressure gained by the height of the pump [bar]
- P_{min} is the minimum backpressure required at top side facilities in the returning fluid [bar]

The power output of the return pump is estimated from the pressure increase by the pump and the flow.

$$P_{P\ out} = P_P \times 100 \times \frac{Q_P}{60000}$$

Where:

- $P_{P\ out}$ is the return pump hydraulic power output [kW]
- $Q_P$is the return pump flow rate [lpm]

The required input power to the return pump is estimated by the pump efficiency.

$$P_{P\ in} = \frac{P_{P\ out}}{\eta_P}$$

Where:

- $P_{P\ in}$ is the mechanical input power to the return pump [kW]
- η_P is the efficiency of the pump

The absorbed power by the pump can be more accurate calculated with a known pump data specification sheet.

The pressure loss in the mud motor is a function of the flow and the required power output of the motor, and is estimated by:

$$P_{M\ out} = \frac{P_{M\ in}}{\eta_M}$$

$$P_M = \frac{P_{M\,in} \times 100 \times 60000}{Q_M}$$

Where:

- $P_{M\,out}$ is the mechanical output power from the mud motor [kW]
- $P_{M\,in}$ is the hydraulic input power to the mud motor [kW]
- P_M is the pressure drop in the mud motor [bar]
- Q_M is the flow rate through the motor [lpm]

This is only a coarse estimate to find the limitations of the system. The differential pressure over the motor will increase until the required pump torque and power has been obtained to balance the power absorbed by the pump. Therefore, the actual differential pressure over the mud motor depends on both the pump and motor design.

The hydraulic horsepower over the drill bit nozzles are, as mentioned earlier, calculated by:

$$P_{hHSI} = \frac{(P_{BHA} - 5) \times 100 \times Q_A}{35140 \times D^2}$$

Were:

- P_{hHSI} is the hydraulic power at the drill bit nozzles [hp/in^2]
- $(P_{BHA}$ is the differential pressure over the BHA and the bottom hole [bar]
- Q_A is the flow rate though the annulus and BHA [lpm]
- D is the diameter of the drill bit [in]

4.6.1 Example Pressure Distribution Single Pump System

An example is presented to illustrate the pressure distribution of the Single pump system.

The table below shows the parameter values selected for the example.

Parameter	Value
Drill bit size	26”
Water depth	250 m
Well length	500 m
Height to drill floor	40 m
Height BHA	27 m
Height motor	18 m
Height pump	13 m

Flow	900 lpm
Bypass flow	200 lpm
Density applied mud	1100 kg/m^3
Density return fluid	1230 kg/m^3
Viscosity supply	18,36 cP
Viscosity return	20,52 cP
Cutting contents	10 %
Motor efficiency	0,72
Pump efficiency	0,72

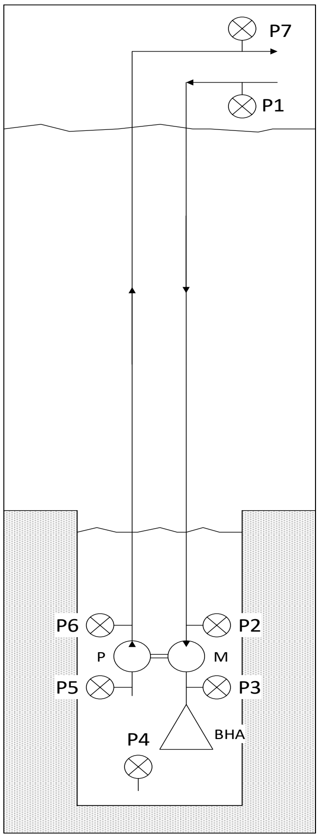
Table 14 Example Pressure distribution, input values

The calculations are shown in the following table.

Parameter	**Formula**	**Calculation**	**Value**
$\boldsymbol{\Delta P_{fIP}}$	$= \frac{L_P \times \rho_P^{0,8} \times Q_P^{1,48} \times \mu_P{}^{0,2}}{C_{MN} \times D_{iIP}^{4,8}}$	$= \frac{727 \times 1,23^{0,8} \times 900^{1,8} \times 20,52^{0,2}}{901,63 \times 2,95^{4,8} \times 100}$	$\approx 20\ bar$
$\boldsymbol{\Delta P_{fTJ}}$	$= \frac{L_{TJ} \times \rho_M^{0,8} \times Q_M^{1,8} \times \mu_M{}^{0,2}}{C_{MN}\left(D_{iTJ} + D_{oIP}\right)^{1,8}\left(D_{iTJ} - D_{oIPC)}\right)}$	$= \frac{33 \times 1,1^{0,8} \times 810^{1,8} \times 18,36^{0,2}}{706,96 \times 100(5 + 4,291)^{1,8}(5 - 4,291)^3}$	$\approx 8\ bar$
$\boldsymbol{\Delta P_{fPB}}$	$= \frac{L_{PB} \times \rho_M^{0,8} \times Q_M^{1,8} \times \mu_M{}^{0,2}}{C_{MN}(D_{iPB} + D_{oPB})^{1,8}(D_{iPB} - D_{oIP})^3}$	$= \frac{727 \times 1,1^{0,8} \times 810^{1,8} \times 18,36^{0,2} \times 0,01}{706,91(5,906 + 3,504)^{1,8}(5,906 - 3,504)^3}$	$\approx 5\ bar$
$\boldsymbol{\Delta P_{fA}}$	$= \Delta P_{fTJ} + \Delta P_{fPB}$	$= 8 + 5$	$= 13\ bar$
$\boldsymbol{P_P}$	$g[\rho_P(h_{DF} + h_{SW} + h_W - h_{BHA} - h_M) - \rho_{SC}(h_W - h_{BHA} - h_M) - \rho_{SW}h_{SW}] + P_{fIP} + 0,5P_{fSE} + P_{min}$	$9,81/100000[1230(40 + 250 + 500 - 45) - 1100(500 - 45) - (1025 \times 250)] + 20 + 5 + 5$	$= 46\ bar$
$\boldsymbol{HP_{Pout}}$	$= P_P \times 100 \times Q_P / 44750$	$= 46 \times 100 \times \frac{900}{44750}$	$= 93\ kW$
$\boldsymbol{HP_{Pin}}$	$= \frac{HP_{Pout}}{\eta_P}$	$= \frac{93}{0,72}$	$= 128\ kW$
$\boldsymbol{HP_{Mout}}$	$= \frac{HP_{Min}}{\eta_M}$	$= \frac{128}{0,72}$	$= 178\ kW$
$\boldsymbol{P_M}$	$= \frac{HP_{Min} \times 100 \times 44750}{Q_M}$	$= \frac{178 \times 44750 \times 0,01}{900 - 200 - 0,1 \times 900}$	$= 131\ bar$
Pressure distribution			

$\boldsymbol{P1}$		$= 320$	$= 320\ bar$
$\boldsymbol{P2}$	$= P1 - P_{fA} - 0{,}5 \times P_{fSE} + g \times \rho_M \times (h_{DF} + h_{SW} + h_W - h_{BHA} - h_M)$	$= 320 - 13 - 5 + (9{,}81 \times 1100 \times (40 + 250 + 500 - 45)/100000$	$= 383\ bar$
$\boldsymbol{P3}$	$= P2 - P_M + g \times \rho_M \times h_M$	$= 383 - 131 + (9{,}81 \times 1100 \times 18/100000)$	$= 254 bar$
$\boldsymbol{P4}$	$= g[\rho_{SC}(h_W - h_{BHA} - h_M) + \rho_P(h_{BHA} + h_M) + \rho_{SW} h_{SW}] + 3$	$= \frac{9{,}81}{100000}[1100 \times (500 - 45) + 1230 \times 45) + 1025 \times 250] + 3$	$= 83\ bar$
$\boldsymbol{P5}$	$= g[\rho_{SC} h_W + \rho_{SW} h_{SW}]$	$= \frac{9{,}81}{100000}[1100 \times (500 - 45) + 1025 \times 250]$	$= 74 bar$
$\boldsymbol{P6}$	$= P5 + P_P$	$= 74 + 45$	$= 120\ bar$
$\boldsymbol{P7}$	$= P6 - g\rho_P(h_{SW} + h_W + h_{DF} - h_{BHA} - h_M - h_P) - P_{fIP} - P_{fSE}$	$= 115 - 9{,}81 \times \frac{1230}{100000}(250 + 500 + 40 - 45 - 13) - 20 - 5$	$= 7 bar$
$\boldsymbol{P_{BHA}}$	$= P3 - P4$	$= 275 - 82$	$= 166\ bar$
$\boldsymbol{P_{hHSI}}$	$= \frac{(P_{BHA} - 5) \times Q_{M+BP}}{35140 \times D^2}$	$= \frac{(166 - 5) \times 100 \times 810}{35140 \times 26^2}$	$= 0{,}57$

Table 15 Example Pressure Distribution Single Pump System



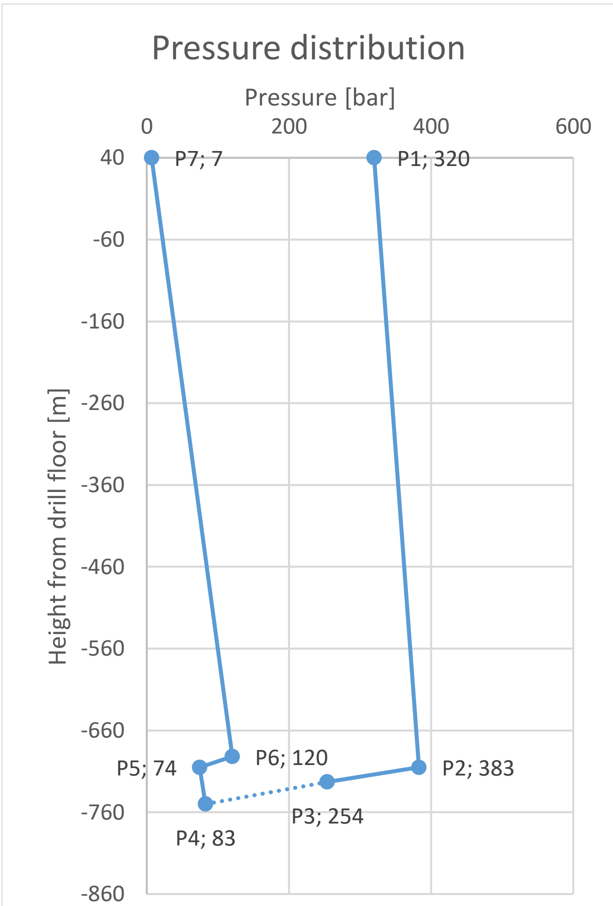


Figure 26 Pressure distribution Single Pump System

Figure 27 Example Pressure distribution, Single Pump System

The pressure drop available for the drill bit nozzles are estimated to 166 bar. This pressure drop will decrease with increasing water depth and well length, due to increasing frictional and hydrostatic pressures.

4.6.2 Single Pump System Pressure Distribution During Circulation Start-up

The pressure distribution during start-up of circulation is dependent upon:

- The gel strength in the annulus and inner pipe
- The hydrostatic differential pressure between the bottom hole and the annulus and the bottom hole and the inner pipe
- The crack open pressure of the DSV and check valve
- The minimum start pressure of the motor and pump

This pressure is expected to be higher than that of normal flow, and pressure peak during start-up is also normal in conventional drilling. The start-up pressure should be accounted for in the selection of mud specifications, pump and motor design and crack open pressure of DSV and check valve.

After flow has been initiated a pressure drop is expected due to the subtraction of resistance in the DSV and check valve, the gel strength vanishes and the inertial forces in the pump and motor are overcome.

With increasing flow rates, the resistance in the inner pipe and annulus and the power demand of the pump will rise. This causes increased pressure drop over the motor and the topside pressure increases.

A start-up and ramp-up pressure development is expected to look somewhat like the illustration below.

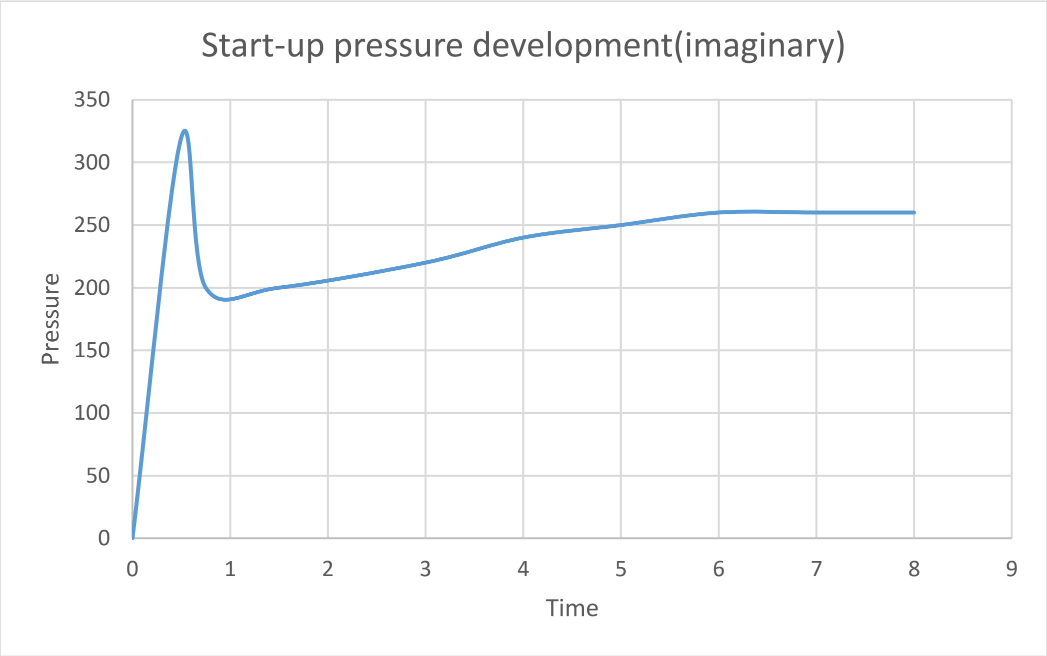


Figure 28 Start-up Pressure Peak Graph

4.6.3 Example start-up of circulation

The following parameters state a start-up scenario:

- Gel breaking pressure: 19 bar
- Start-up pressure of the mud motor: 17 bar
- Starting torque of the pump is 1600 Nm and the associated motor pressure drop is 35 bar
- The added hydrostatic pressure up the return pipe is 15 bar

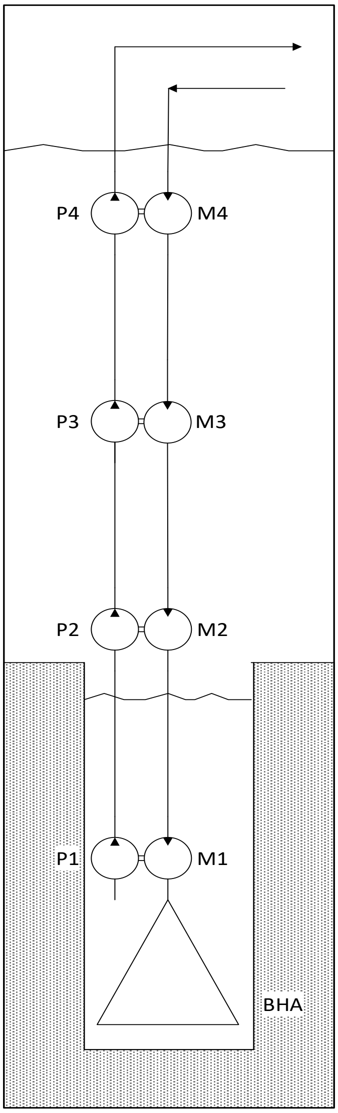
The differential pressure over the return motor, to start circulation is:

$$P_{start} = P_{start\ motor} + P_{gel\ strength} + P_h + P_{start\ pump} = 17 + 19 + 15 + 35 = 86\ bar$$

The DSV crack open pressure also needs to be taken in to account. But due to the motor bypass, the pressure will build up on both sides of the motor, until the DSV opens. Then the motor and the drill bit nozzles are the flow restrictors, and the pressure over the drill bit and motor will increase.

4.7 Multiple Pump System Pressure distribution

The pressure distribution of the multiple Pump System is built on the same foundations as the Single Pump System. The pressures down the annulus of the DDS will increase with added hydrostatic



pressure, and decrease with pressure loss in surface equipment, annulus and mud motors. The pressure drops over the mud motors are functions of the required pump power. The same formulas have been applied, as for the Singe Pump System, but they are adjusted to several pump-motor sets and DDS segments.

In the inner pipe the discharge pressure in each pump should be sufficient to pump the fluid and solids to the next pump. This is repeated until drill floor.

There are uncertainties with regards to imbalance between the pump-motor sets. An unbalance between the pump-motor sets imply a higher pressure increase in one of the pumps, leading to a lower necessary differential pressure over the next pump. This would cause an uneven pressure distribution in the annulus conduit as well, with a higher differential pressure over the motor associated with the higher performing pump. Due to the motor bypass, the flow through the motors can be differentiated, giving root to variable RPM between each pump-motor set. This uncertainty is further evaluated in the Chapter evaluating the system behavior.

Figure 29 Pressure Distribution, The Multiple Pump System with four motor-pump sets

4.7.1 Example Pressure distribution in The Multiple Pump System

An example is presented to illustrate the pressure distribution of The Multiple Pump System.

The illustration above shows the Multiple pump system, configurated with four pump-motor sets. The table below shows the parameter values selected for the example.

Parameter	Value
Drill bit size	26”
Water depth	250 m
Well length	500 m
Length between each pump-motor set	191,25 m
Height to drill floor	40 m
Height BHA	17 m

Height motor	8 m
Height pump	8 m
Flow	900 lpm
Bypass flow	200 lpm
Density applied mud	1100
Density return fluid	1230 kg/m^3
Viscosity supply	18,36 cP
Viscosity return	20,52 cP
Cutting contents	10%
Motor efficiency	0,72
Pump efficiency	0,72

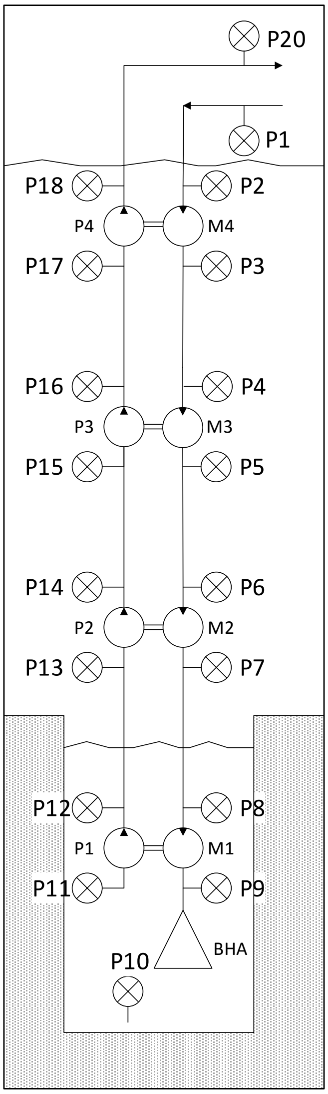
Table 16 Example Pressure distribution, input values

The calculations are shown in the following table.

Parameter	Formula	Calculation	Value
$\Delta \boldsymbol{P}_{fIP}$	$= \frac{L_P \times \rho_P^{0,8} \times Q_P^{1,48} \times \mu_P{}^{0,2}}{C_{MN} \times D_{iIP}^{4,8}}$	$= \frac{191{,}25 \times 1{,}23^{0,8} \times 900^{1,8} \times 20{,}52^{0,2}}{901{,}63 \times 2{,}95^{4,8} \times 100}$	$\approx 6\ bar$
$\Delta \boldsymbol{P}_{fTJ}$	$= \frac{L_{TJ} \times \rho_M^{0,8} \times Q_M^{1,8} \times \mu_M{}^{0,2}}{C_{MN}\left(D_{iTJ} + D_{oIP}\right)^{1,8}\left(D_{iTJ} - D_{oIPC)}\right)}$	$= \frac{9 \times 1{,}1^{0,8} \times 810^{1,8} \times 18{,}36^{0,2}}{706{,}96 \times 100(5 + 4{,}291)^{1,8}(5 - 4{,}291)^3}$	$\approx 1 bar$
$\Delta \boldsymbol{P}_{fPB}$	$= \frac{L_{PB} \times \rho_M^{0,8} \times Q_M^{1,8} \times \mu_M{}^{0,2}}{C_{MN}(D_{iPB} + D_{oPB})^{1,8}(D_{iPB} - D_{oIP})^3}$	$= \frac{191{,}25 \times 1{,}1^{0,8} \times 810^{1,8} \times 18{,}36^{0,2} \times 0{,}01}{706{,}91(5{,}906 + 3{,}504)^{1,8}(5{,}906 - 3{,}504)^3}$	$\approx 2 bar$
$\Delta \boldsymbol{P}_{fA}$	$= \Delta P_{fTJ} + \Delta P_{fPB}$	$= 1 + 2$	$= 3 bar$
$\boldsymbol{P}_{\boldsymbol{P}}$	$g[\rho_P(h_{DF} + h_{SW} + h_W - h_{BHA} - h_M) - \rho_{SC}(h_W - h_{BHA} - h_M) - \rho_{SW} h_{SW}] + 4P_{fIP} + 0{,}5P_{fSE} + P_{min}$	$9{,}81/100000[1230(40 + 250 + 500 - 25) - 1100(500 - 25) - (1025 \times 250)] + 24 + 5 + 5$	$= 55 bar$
$\boldsymbol{HP}_{\boldsymbol{Pout}}$	$= P_P \times 100 \times Q_P / 44750$	$= 55 \times 100 \times \frac{900}{44750}$	$= 111\ kW$
$\boldsymbol{HP}_{\boldsymbol{Pin}}$	$= \frac{HP_{Pout}}{\eta_P}$	$= \frac{111}{0{,}72}$	$= 154 kW$
$\boldsymbol{HP}_{\boldsymbol{Mout}}$	$= \frac{HP_{Min}}{\eta_M}$	$= \frac{154}{0{,}72}$	$= 213\ kW$

$\boldsymbol{P_M}$	$=\frac{HP_{Min}\times 100\times 44750}{Q_M}$	$=\frac{213\times 44750}{900-200-0{,}1\times 900}$	$=156\ bar$
Pressure distribution			
$\boldsymbol{P1}$		$=320$	$=320\ bar$
$\boldsymbol{P2}$	$=P1-P_{fA}-0{,}5\times P_{fSE}+g\times\rho_M\times h_1$	$=320-3-5+(9{,}81\times 1100\times 191{,}25$ $/100000$	$=\ 332\ bar$
$\boldsymbol{P3}$	$=P2-P_M+g\times\rho_M\times h_M$	$=332-156/4+(9{,}81\times 1100\times 8/100000)$	$=294\ bar$
$\boldsymbol{P4}$	$=P3-P_{fA}+g\times\rho_M\times h_1$	$=294-3+(9{,}81\times 1100\times 191{,}25/100000$	$=\ 312\ bar$
$\boldsymbol{P5}$	$=P4-P_M+g\times\rho_M\times h_M$	$=312-156/4+(9{,}81\times 1100\times 8/100000)$	$=274\ bar$
$\boldsymbol{P6}$	$=P5-P_{fA}+g\times\rho_M\times h_1$	$=274-3+(9{,}81\times 1100\times 191{,}25/100000$	$=\ 291\ bar$
$\boldsymbol{P7}$	$=P6-P_M+g\times\rho_M\times h_M$	$=291-156/4+(9{,}81\times 1100\times 8/100000)$	$=253 bar$
$\boldsymbol{P8}$	$=P5-P_{fA}+g\times\rho_M\times h_1$	$=253-3+(9{,}81\times 1100\times 191{,}25/100000$	$=\ 270\ bar$
$\boldsymbol{P9}$	$=P6-P_M+g\times\rho_M\times h_M$	$=270-156/4+(9{,}81\times 1100\times 8/100000)$	$=231 bar$
$\boldsymbol{P10}$	$=g[\rho_{SC}(h_W-h_{BHA}-h_M)$ $+\rho_P(h_{BHA}+h_M)$ $+\rho_{SW}h_{SW}]+3$	$=\frac{9{,}81}{100000}[1100\times(500-25)+1230\times 25)$ $+1025\times 250]+3$	$=82 bar$
$\boldsymbol{P11}$	$=g[\rho_{SC}h_W+\rho_{SW}h_{SW}]$	$=\frac{9{,}81}{100000}[1100\times(500-25)+1025\times 250]$	$=76\ bar$
$\boldsymbol{P12}$	$=P11+P_P$	$=76+\frac{55}{4}$	$=89\ bar$
$\boldsymbol{P13}$	$=P12-g\rho_P(h_1)-P_{fIP}$	$=89-9{,}81\times\frac{1230\times 191{,}25}{100000}-6$	$=60 bar$
$\boldsymbol{P14}$	$=P13+P_P$	$=60+\frac{55}{4}$	$=73\ bar$
$\boldsymbol{P15}$	$=P14-g\rho_P(h_1)-P_{fIP}$	$=73-9{,}81\times\frac{1230\times 191{,}25}{100000}-6$	$=44\ bar$
$\boldsymbol{P16}$	$=P15+P_P$	$=44+\frac{55}{4}$	$=57\ bar$
$\boldsymbol{P17}$	$=P16-g\rho_P(h_1)-P_{fIP}$	$=57-9{,}81\times\frac{1230\times 191{,}25}{100000}-6$	$=27\ bar$
$\boldsymbol{P18}$	$=P17+P_P$	$=44+\frac{55}{4}$	$=40\ bar$
$\boldsymbol{P19}$	$=P17-g\rho_P(h_1)-P_{fIP}-0{,}5\times P_{fSE}$	$=40-9{,}81\times\frac{1230\times 191{,}25}{100000}-6-5$	$=6\ bar$
$\boldsymbol{P_{BHA}}$	$=P3-P4$	$=275-82$	$=145\ bar$
$\boldsymbol{P_{hHSI}}$	$=\frac{(P_{BHA}-5)\times Q_{M+BP}}{35140\times D^2}$	$=\frac{(145-5)\times 100\times 810}{35140\times 26^2}$	$=0{,}55$

Table 17 Example Pressure Estimation Multiple Pump System



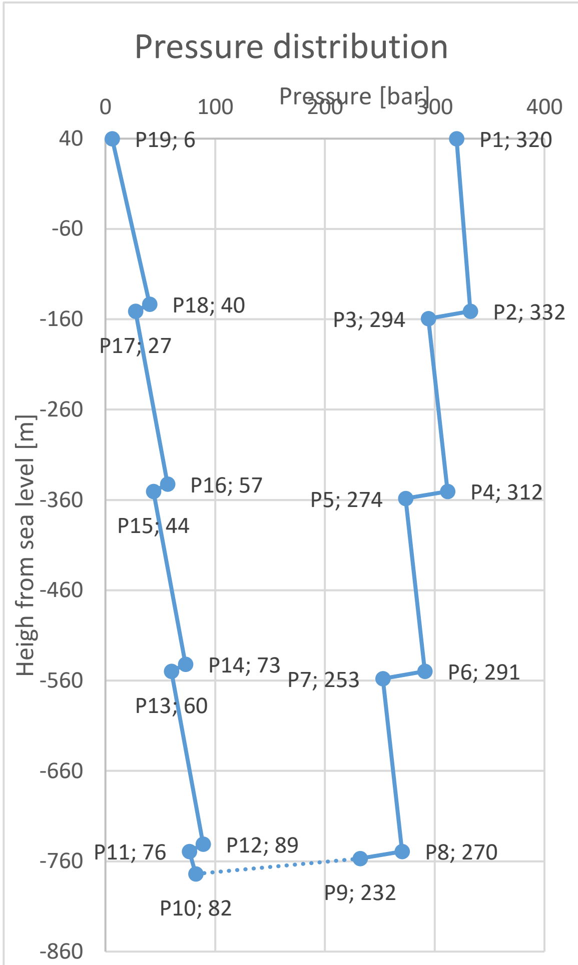


Figure 30 Pressure distribution Multiple Pump System

Figure 31 Pressure Graph Distribution Multiple Pump System

4.8 Results base case pressure estimations

The following graph shows the estimated pressure distribution in the Single Pump System for the base case. The additional lines illustrate how much of the total pressure that is caused by hydrostatic head and frictional pressure loss. The red lines are the frictional pressure loss. The frictional loss is set to zero at the selected ending points, the motor and topside. The hydrostatic amount of the measured pressure is set to zero at top side, and is marked by the grey lines. The amount of hydrostatic pressure of the total pressure increases down the pipe. The amount of frictional pressure of the total pressure decreases to the ending point.

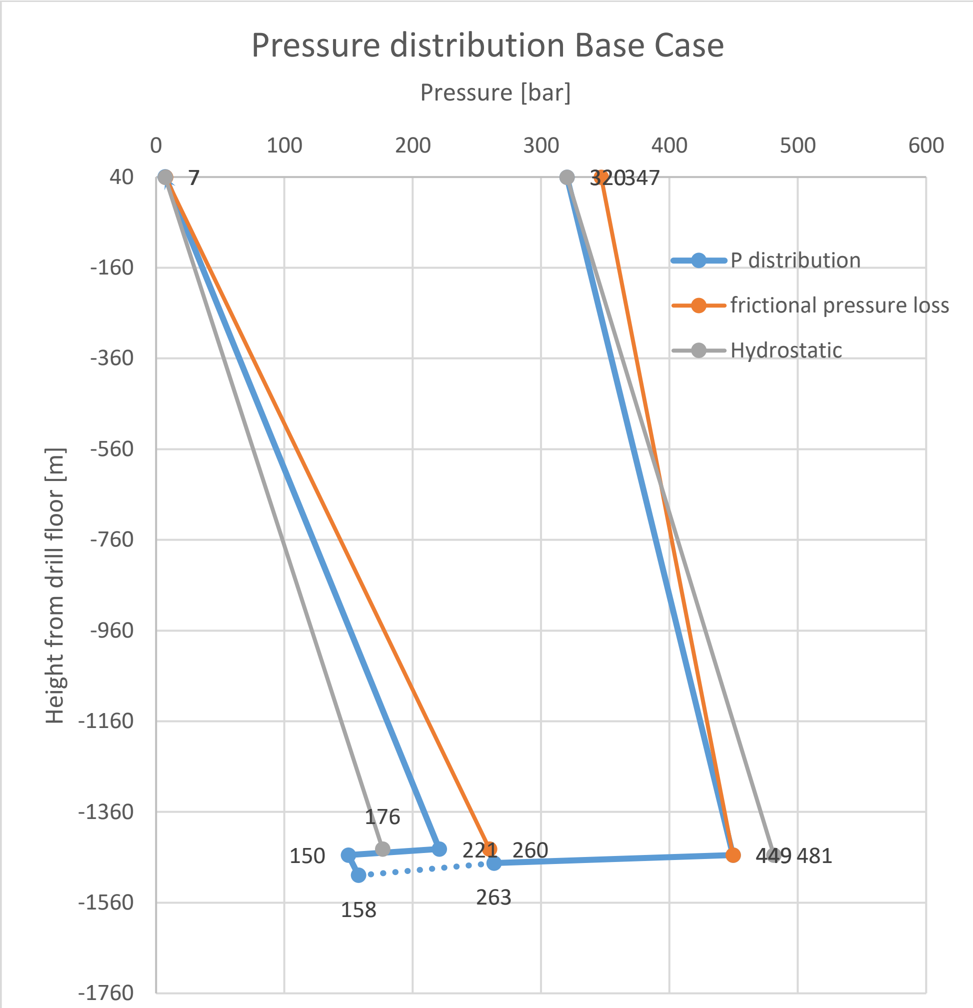


Figure 32 Pressure distribution base case Single pump system

The hydraulic power of the return pump is estimated to $P_{P\ out} = 107\ kW$, and the mechanical power of the motor is estimated to $P_{M\ out} = 148\ kW$. The HSI is estimated to 0,36. The frictional pressure loss in the inner pipe was estimated to 39 bar, and in the annulus to 27 bar.

For the Multiple Pump System, configurated with four motor-pump sets, 378,5 meters apart. The pressure distribution looks like the graph below. The frictional pressure loss of each segment was calculated to t bar in the annulus, and 10 bar in the inner pipe. The hydraulic power of a return pump is estimated to $P_{P\ out} = 29\ kW$ and the mechanical power of a motor is estimated to $P_{M\ out} = 40\ kW$.

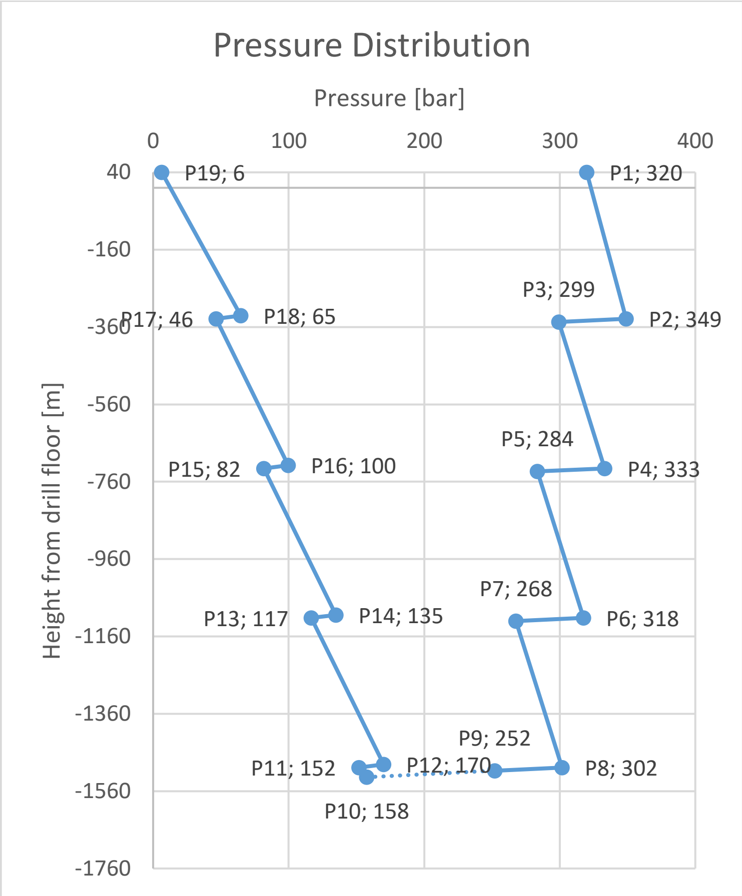


Figure 33 Pressure distribution base case Multiple pump system

4.9 Discussion Pressure Estimations

One of the assumptions made during the estimation of the pressure distribution within the systems is that the differential pressure over the drill bit nozzles will not affect the differential pressure over the motor. And as stated earlier, the differential pressure over the drill bit nozzles are assumed to adjust itself to the available pressure drop. However, the flow restriction through the nozzles vary with the design of the nozzles and the fluid characteristics. It is important that the drill bit is selected in accordance with expected available differential pressure over the drill it.

The pressure drop of the motors is a factor of the efficiency of the motor and pump. If the efficiency of the motor and pump is lower than 0,72, than the required pressure drop over the motor will increase. The efficiency of the motor and pump will also wary with flow and fluid properties. To obtain more accurate pressure calculations, the pump and motor data sheet should be employed.

5 MUD LEVEL REGULATION PRINCIPLE AND MOTOR-PUMP FUNCTIONING

The regulation of the mud level in the drilled hole is necessary to stabilize the well and to avoid mud and cutting discharges to the sea floor. The regulation of the mud level should be practical, efficient and reliable, the pump wear and drilling parameters must be considered. Stable operation of the level is preferable, but at the same time it must be possible to adjust the level within reasonable time limits. In this section, the mud level regulation principle will be explained and analyzed, and the influence of differential pressure and motor and pump design is highlighted.

5.1 Presentation of The Level Regulation Principle

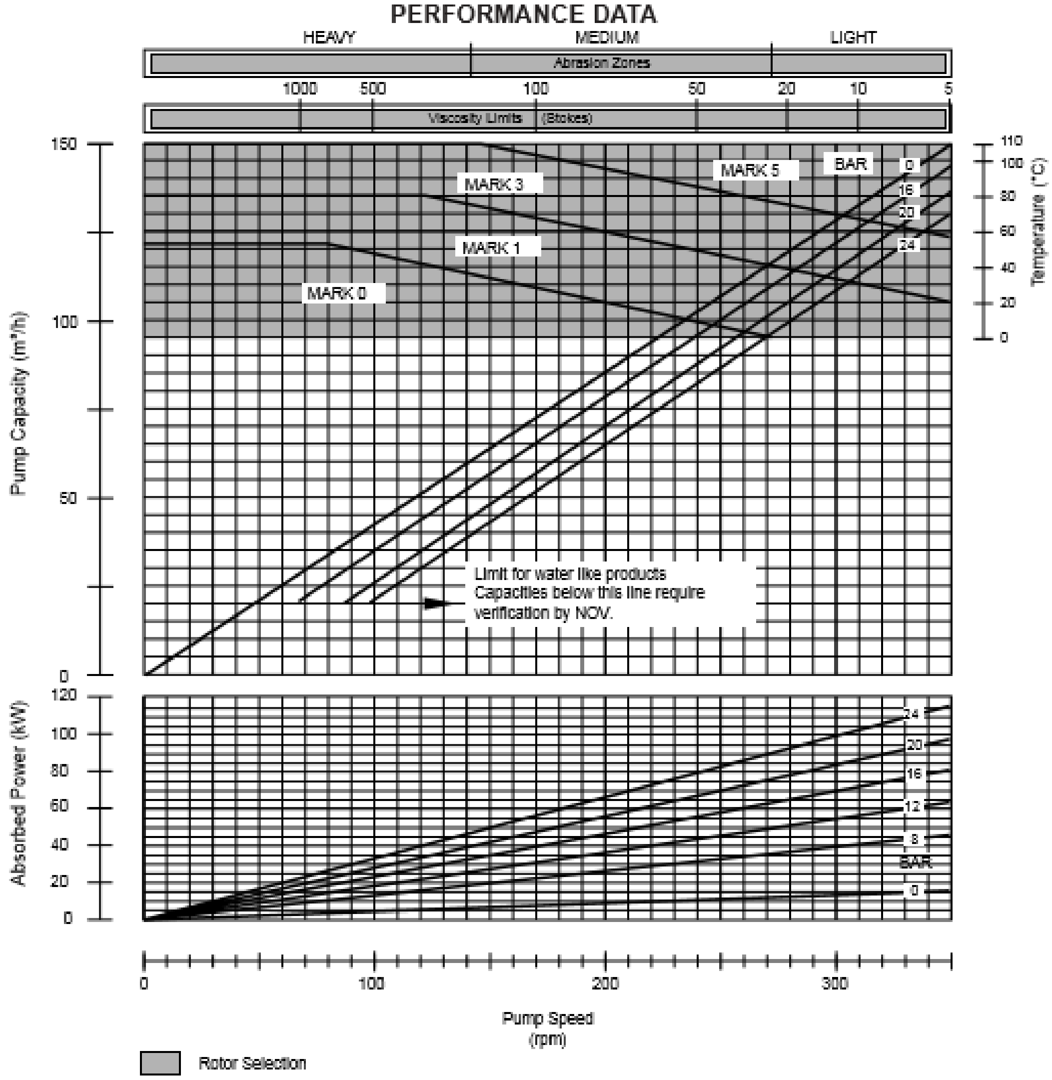
To account for pump wear, variable rates of cuttings generation with variable ROPs, and inflow from the sediments, a mud level regulation principle has been developed. This principle allows the driller to adjust the fill/drain rate of the mud level in the hole.

During the analyses of the Level Regulation Principle a PC pump and a mud motor has been selected to represent the return pump and motor in the Multiple Pump System. The pressure capacity of the pump-motor pair is according to estimates suitable for top holes of close to 500 meters deep, with densities up to 1100 kg/m^3, in 1000 meters water depth. The Multiple Pump System should be configured with 4 sets in series, 191 meters apart. Full specifications sheets for motor and pump are found below. Note that the specifications are valid for water at 20° Celsius for the pump and 21° Celsius for the motor. Figure 34, is supplied by Axflow AS, and shows the parameters for NOV's PC pump Epsilon E1BD. Figure 35, is taken from NOV's Mud Motor Handbook.[22]

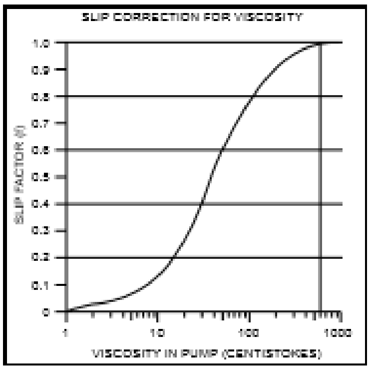
PUMP RANGE	EPSILON
MONO™ MODEL	E1BD
STATUS	CURRENT

SECTION	2
PAGE	12401
DATE	Sept 2007

PERFORMANCE DATA



SLIP CORRECTION	n = corrected duty speed, n_o = rpm @ 0 bar, n_b = rpm @ duty press. n_s = Slip Speed = $n_0 - n_b$, f x n_s = Slip Speed Correction = f.n_s *Slip Corrected Speed (n = n_0 - f.n_s)*					
TEST PARAMETERS	Above data represents tests on water @ 20°C using RR and RA stator materials.					
FOOD APPLICATIONS	Check customer CIP process if available. Refer to Section 1 for CIP suitability					
	SOLIDS HANDLING (mm)		STARTING TORQUE (Nm)			
	Hard Angular	Soft and compressible	Mark 0	Mark 1	Mark 3	Mark 5
EPSILON	25	75	2800	1600	1600	1600



Published information other than that marked certified is to be used as a guide only

Figure 34 NOV PC pump, Epsilon E1BD

Figure 35 NOV mud Motor data sheet

Recommended Operating Limits

Flow Range	100 - 250 gpm	379 - 946 lpm
Revs per Unit Volume (No Load)	1.01 rev/gal	0.268 rev/L
Speed (No Load)	101 - 253 rpm	
Approx Press Drop @ 250 gpm (No Load)	250 psi	1700 kpa

Performance Output

Std Elastomer Max Diff Pressure	840 psi	5792 kPa
Std Elastomer Torque @ Max Pressure	2011 lb-ft	2726 N-m
PowerPLUS™ Max Diff Pressure	**1260 psi**	**8687 kPa**
PowerPLUS Torque @ Max Pressure	**3016 lb-ft**	**4090 N-m**

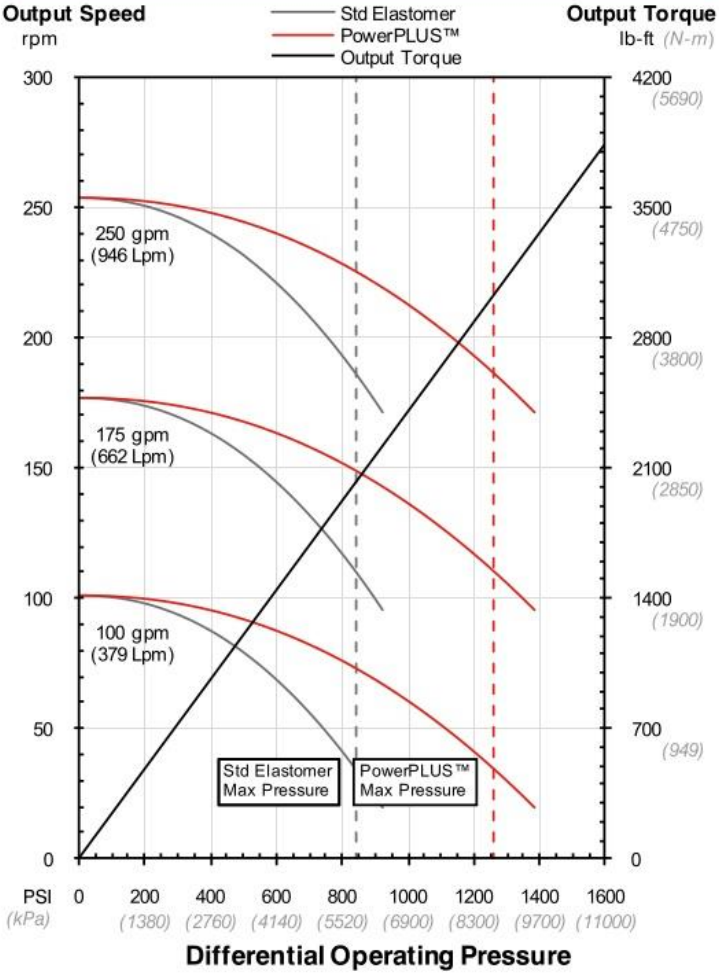
Fit Availability for All Elastomers

	US	STD	OS	2xOS
Availability		✓		✓

Refer to Power Section Fits on page 33 to correctly choose power section for drilling application.

Theoretical Performance Curve

*[water @ 70°F (21°C)]***



****For temperatures exceeding 140°F (60°C), decrease the rated Max Differential Pressure limit as per the guide on page 39.**

Performance curves are for reference only. Performance data and dimensions subject to change without notice. Performance curves based upon Dyno testing at 70°F (21°C). Actual field performance may vary with field operating conditions.Operating a power section near or above maximum differential pressure will reduce life.

Principally the driller can adjust two factors to obtain a stable mud level with low or no fill rate;

- ROP
- Topside flow rate

The ROP is a function of geological factors, weight on bit, drilling parameters, drill string RPM, HIS and other factors. The driller's goal is to keep a high ROP without excessive drill bit wear and formation degrading. In order to avoid negative effects for the driller, the ROP is not considered to be a factor the driller can adjust, just to obtain a desirable fill rate. The ROP is regarded as a variable which will affect the rate of cutting generation, and the level regulation should function for a span of ROPs.

The flow rate and pressure from the top side mud pumps is limited by the backpressure from the system, which mainly is a result of flow resistance, mechanical friction and hydrostatic pressure. The frictional resistance in the mud motors reflects the hydraulic and frictional resistance in the return conduit.

The level regulation principle is based on that the driller adjusts the flow rate from the top side mud pumps and thereby obtain variable RPM of the down hole mud motors and return pumps. Keeping in mind that the mud motors and return pumps have the same RPM and that a return pump is selected with a higher displacement than the motor, creates a difference in flow rate into and out of the well. However, with a constant higher flow out of the well than into the well, the mud level would be drained continuously. Therefore, a bypass flow passing the motor, without entering it, will increase the flow into the well without changing the RPM of the motor and pump. This enables both level drainage at high RPM, and high flow rates, and level filling with low RPM, and low flow rates.

5.2 Analysis of the Level Regulation Principle

5.2.1 Simplified estimations of pump and motor displacement during off bottom circulation

The graph below shows the return pump, motor and motor bypass flow out of and into the well. The blue lines represent the displacement of the return pump, and the brown lines the displacement of the motor. The dotted line illustrates the total supply flow, with the motor displacement and the additional bypass flow. The displacement of the PC pump is dependent upon the required lift by the pump, therefore, there are three curves representing the same pump. The displacement of the mud motor is also dependent on the pressure drop over the motor, and the flow rate through the motor at 35 and 55 bar pressure drop are shown.

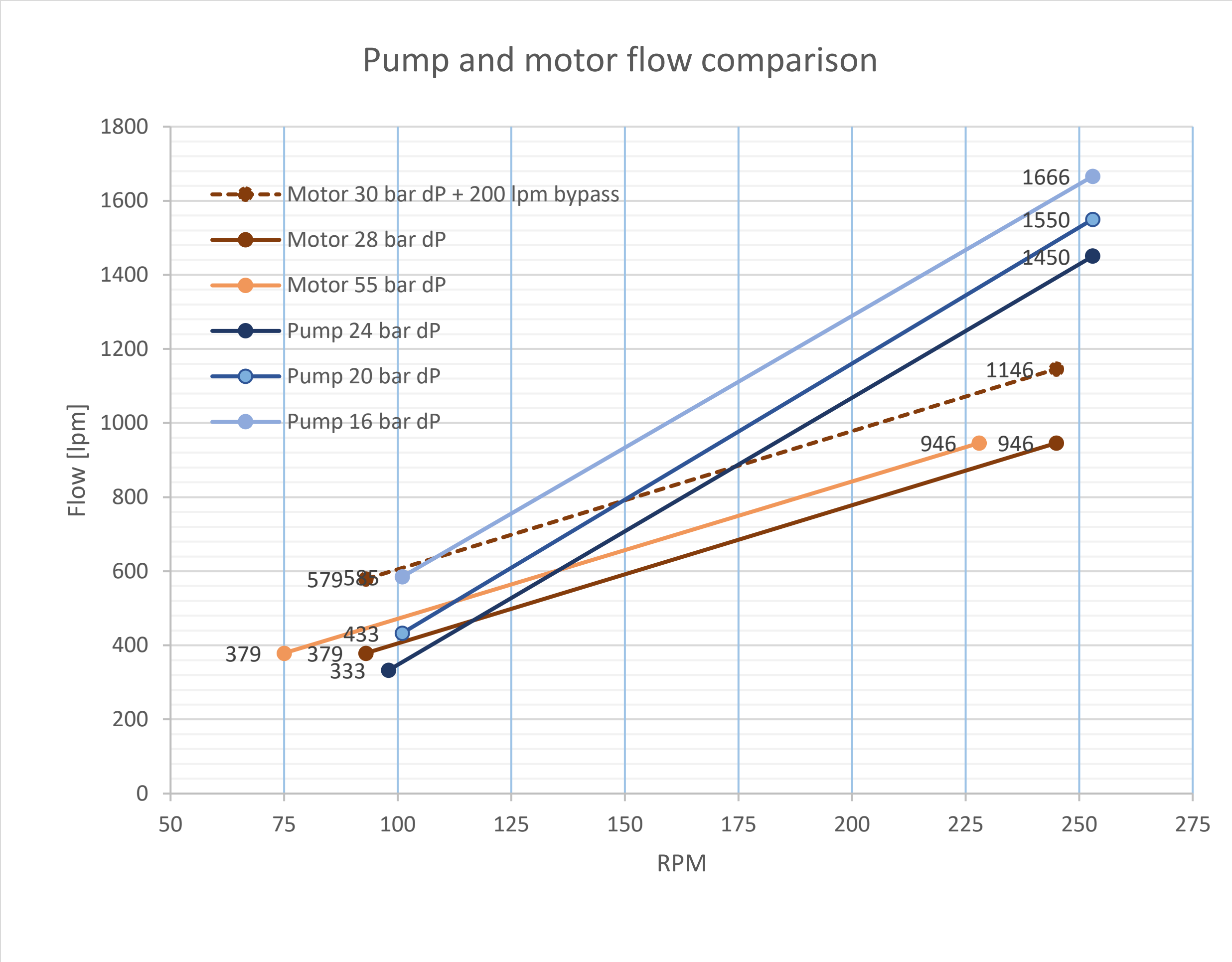


Figure 36 Pump and motor flow comparison

The graph illustrates that with low RPM the flow rate of the return pump is lower than the flow rate trough the motor and bypass. The flow out of the well is lower than the flow into the well and the well mud level will increase. For high RPMs, the situation is opposite: the flow rate of the pump is higher than the flow rate of the motor and flow through the bypass, and the mud level is drained.

The graph also illustrates the effect of the differential pressure over the return pump and motor. With higher pump discharge pressures the slip through the pump increases, and the displacement of the pump decreases. And with increased differential pressure over the motor, more flow is pushed through the motor per revolution, and the displacement increases.

The flow rate affects the frictional pressure loss. And with increasing flow rates, the flow capacity of the pump decreases, and the ability to drain the mud level in the well decreases. In other words, the capacity of the system is reduced. Different system pressures are estimated based on several drilling scenarios. Based on these estimates, the expected pressure drop in the motor and the necessary lift by the pump is obtained, such that the flow rates and ROM can be compared. A short example follows.

5.2.2 Example 1: Flow rates during off bottom circulation

In the data obtained from the pressure distribution estimates; 26” drill bit, drilling a 1000 meter long well in 100 meter water depth with a density of 1100 kg/m^{3}and 1200 lpm, should yield a necessary pump lift pressure of 20 bar, and a pressure drop of 45 bar in the mud motor. The flow rate curves are adjusted to fit the pressure drop and shown below.

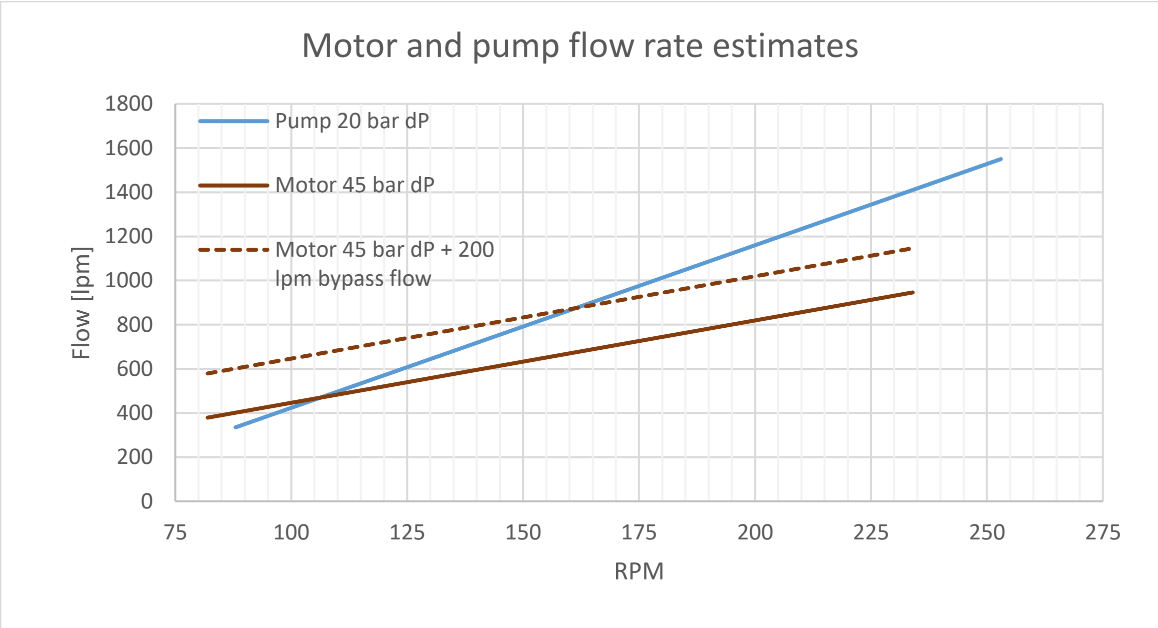


Figure 37 Motor and pump flow estimation of drilling scenario 1

The graph shows that during circulation with no ROP or inflow from the sediments, the level is drained with a flow of under 200 lpm. By decreasing the mud supply flow rate to 600 lpm, the mud level should be more stable. However, due to the decreased pressure drop to and from the well, new differential pressure over motor and pump must be considered so that new displacement of the motor and pump are found. The new required pressure increase in the pump is 10 bar and the pressure drop in the motor is estimated to 28 bar. The new displacement-per-RPM curve is shown below.

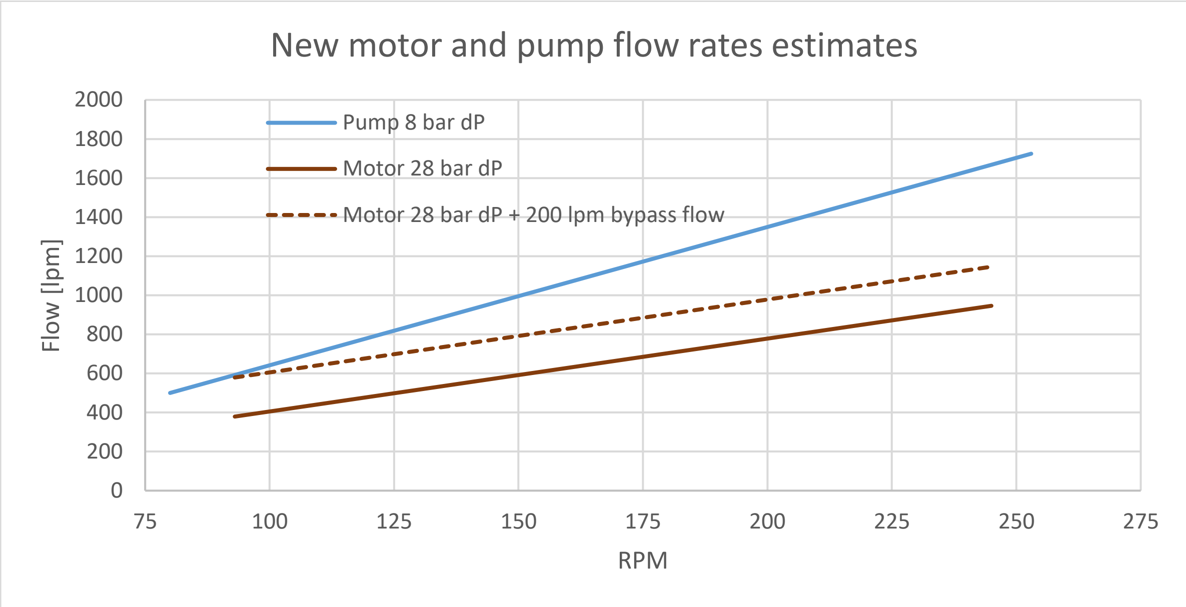


Figure 38 Motor and pump flow estimate of drilling scenario 2

The new mud supply flow, through the motor and bypass, is now close to the flow rate of the pump. The driller can circulate without draining the mud level. However, the size of the bypass might be in the lower range of what is acceptable, leaving poor filling operationality.

5.2.3 Simplified estimations of motor and pump displacement while drilling

During penetration, additional factors must be considered:

- Cuttings generation rate
- Increasing well volume
- Pipe volume entering the well
- Inflow from or loss to formation

All flows into and out of the well and the increasing well and pipe volume needs to be accounted for to obtain mud level regulation in the well.

To keep the level steady during drilling, the flow through the return pump should equal:

$$Q_P = Q_M + Q_{bypass} + Q_C + Q_{Inflow} - Q_{cutting\ displacement}$$

Where:

- Q_P is the displacement of the pump [lpm]
- Q_M is the displacement of the motor [lpm]
- $Q_C$is the genetaion rate of cuttings [lpm]
- Q_{Inflow} is the loss or gain due to inflow or outflow from the sediments [lpm]
- $Q_{cutting\ displacement}$ is the mud used to fill the well hole

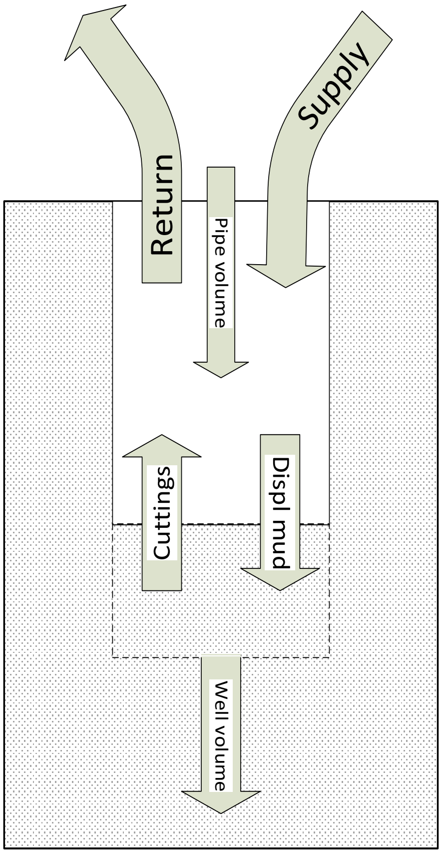


Figure 39 Volume flows during drilling

Cuttings generation is a product of the ROP and the drill bit diameter. As the well length increase, the cavity between the hole walls and the drill pipe should be filled with mud. These two volume flows are almost the same, the drilled cuttings are pumped up and replaced by mud and drill pipe.

Possible inflow from the formation is disregarded in the illustration, but is expected to be of a size capable to be controlled by the system, employing both the THLT and the regulation principle. The illustration above shows all parameters to be considered during drilling.

During tripping out of the hole, the volume of the DDS and BHA is subtracted, and the level in the well will decrease. To keep the level within optimum limits this should be accounted for, perhaps by adjusting the level before tripping.

5.2.4 Example 2: Level regulation and generated volumes

An example to illustrate the *generated volumes* during drilling of an 80-meter section follows.

Example:	
Length drilled [m]	80
Drill bit diameter [m]	0,6604 [26in]
Average ROP [m/h]	40

Generated volume of cuttings [m³]	27,4
RPM motors and pumps	152
Flow rate motor [lpm]	855
Flow rate pump [lpm]	900
Generated volumes during drilling of the 80-meter section	
Mud pumped into well [m³]	102,6
Drilling fluids pump out of well [m³]	108
Displaced mud volume between walls and pipe [m³]	25,5
Inflow from reservoir [m³]	0
Excess mud [m³]	-3,5
Level drainage [m]	**10,2**

Table 18 Example of well section drilled with RPM at 152 and ROP at 40 m/h

5.2.5 Example 3: Effects on level regulation by the ROP

Example 1, showed the effect of the pressure over the pump and motor on the flow rates in and out of the well. The ROP must also be carefully considered due to its impact on the pumps lift requirements. By increasing the ROP and keeping supply flow rate steady, the density of the returning fluid increases. This causes higher frictional and hydrostatic pressures to be overcome by the return pump. To illustrate the effect of the ROP on the level regulation, an example is presented below, with a drilling scenario with varying ROP.

The well is presumed drilled with a 26" drill bit and 1100 kg/m^3 mud supply density, in 100 meter water depth. Well depth is set to 500 meter. The bypass flow is kept at the same level, 200 liters per minute, even if this might be a bit low. Applying the pressure estimations for the Multiple Pump System, configurated with four motor-pump sets, the resulting data are listed in the table below.

ROP	**Q_P [lpm]**	**Q_C [lpm]**	**Cutting contents %**	**dP_P [bar]**	**dP_M [bar]**	**RPM**	**Q_M [lpm]**	**$Q_{displ.mud}$ [lpm]**	**Q_{Total} [lpm]**	**Level dev. [m(min]**
	Displacement pump	Cuttings generation		Discharge pressure pump	Motor pressure drop		Displacement motor	Mud to fill cavity		
Variable set	Variable set	$=\frac{ROP}{60}\times A_W\times 1000$	$=\frac{Q_C}{Q_P}$	From estimations	From estimations	From pump data sheet	From motor data sheet	$=\frac{ROP}{60}\times(A_W-A_P)*1000$	$=Q_C+Q_M+Q_{BP}+Q_{Displ.mu}-Q_P$	$=Q\frac{Total}{A_W-A_P}$

0	600	0	0	7	20	90	340	0	-60	-0,19
0	900	0	0	9	22	135	435	0	-265	-0,85
0	1200	0	0	12	28	185	730	0	-270	-0,87
10	600	57	10	10	34	92	300	52	-39	-0,12
10	900	57	6	12	34	138	450	52	-192	-0,62
10	1200	57	5	13	32	187	740	52	-203	-0,65
20	600	114	19	12	48	95	355	104	78	0,25
20	900	114	13	13	37	140	475	104	-108	-0,35
20	1200	114	10	15	39	190	680	104	-207	-0,66
30	600	171	29	14	70	98	440	156	224	0,72
30	900	171	19	14	45	142	485	156	-40	-0,13
30	1200	171	14	16	44	192	650	156	-180	-0,58

Table 19 Level increase with pressure over the return pump.

To obtain the data in the table above, the ROP and flow rate from the return pump has been varied. The differential pressures over the pump and motor is found by using the formulas for estimating the pressure from chapter 4. The RPM is set based on the pump specification sheet with flow and pressure input. The RPM and pressure drop over the motor yields a flow rate through the motor found in the motor specification sheet. It should be noted that the calculations are only rough estimates to try to show the system response and level regulation possibility, with variations in ROP.

The graph below illustrates the possibility for mud level regulation with increasing ROP.

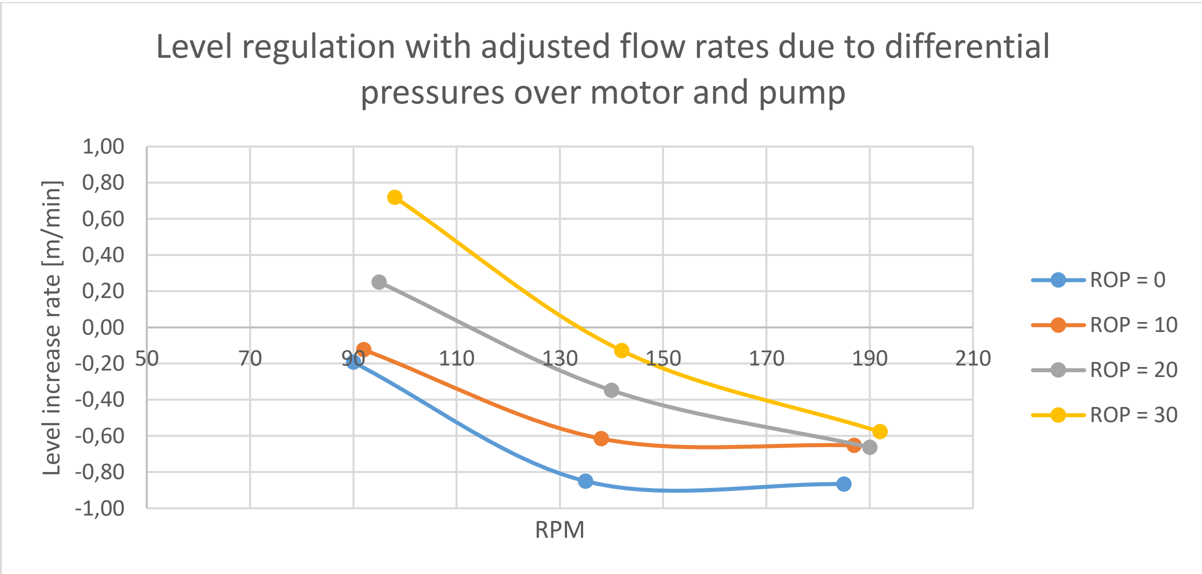


Figure 40 Level regulation with variable ROP

The graph above shows that the system is capable of level regulation with adjusted flow rates due to increased flow resistance in the system, but the bypass flow seems to be too small.

It is expected that the optimum flow rate during penetration is in the upper range of the DDS's flow capacity, 900-1200 liter per minute. However, since the frictional pressure losses increase exponentially, higher pressure losses, at maximum flow rate, shrinks the operational window of the system. Therefore, it may be necessary to reduce the flow rate to around 900-1000 liters per minute. It would be desirable match the difference in supply and return mud flows with the expected ROP, such that the mud level increase rate is near zero at the desirable mud supply flow rate.

5.2.6 Power and Torque

During the pressure and flow estimates in the sections above, the power and torque distribution is not considered. The required pressure differentials are only based on motor and pump performance. Without the correct torque and power distribution between the motor and pump, the system would not function. The motor-pump set will not rotate if the motor cannot generate enough power for the pump.

The power and torque specifications of the pump and motor is dependent upon the design. For mud motors, increasing the number of lobes will increase the torque output, but decrease the RPM, as shown in the illustration under. The picture is taken from Baker Hughes Mud Motor Data Handbook. [23]

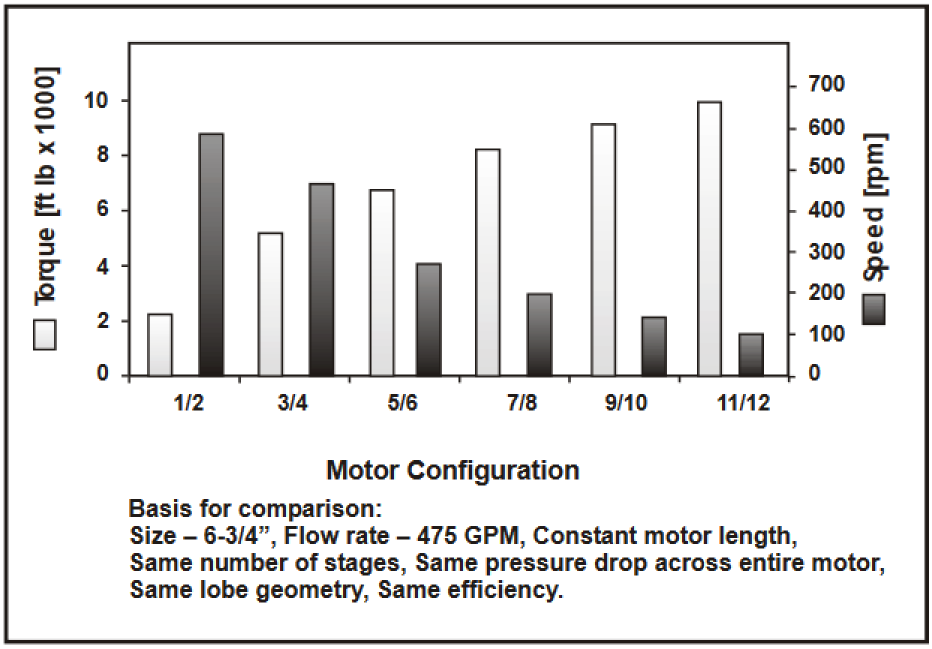


Figure 41 Motor configuration, increasing lobe number

The detailed design or selection of a functional motor-pump set is considered to be beyond the scope of this thesis. It is assumed that it is possible to design a functional set with matching power and torque characteristics. The pump and motor employed in the examples above is further examined to obtain values on power and torque distribution, merely as a theoretical experiment.

By applying motor and pump data sheets, more accurate pressure estimations can be predicted. The required inlet power to the pump is found in the pump data sheet, and the pump torque is calculated from the required pump input power.

$$T_{Pin} = P_{P\,in} \times \frac{9550}{RPM}$$

The motor torque generated by the differential pressure over the motor is found in the motor data sheet. The torque is used to find the mechanical power output.

$$P_{Mout} = \frac{T_{Mout} \times RPM}{9550}$$

Where:

- $T_{P\,in}$ is the torque input to the pump [Nm]
- $P_{P\,in}$ is the power input to the pump [kW]
- P_{Mout} is the mechanical output power of the mud motor [kW]
- T_{Mout} is the mud motor output torque [Nm]

5.2.7 Example 4: Power and torque distribution

Employing the above formulas to the previous data obtained in Example 3, the required pump torque and power are shown. And the motors generated pump and torque are shown in the table below.

ROP	**Q_P [lpm]**	**dP_P [bar]**	**dP_M [bar]**	**RPM**	**Q_M [lpm]**	**$T_{M\,out}$ [Nm]**	**$P_{M\,out}$ [kW]**	**$P_{P\,in}$ [kW]**	**$T_{P\,in}$ [Nm]**
	Displacement pump	Discharge pressure pump	Pressure drop motor	Set by pump	Displacement motor	Motor output torque	Motor output power	Pump require power	Pimp require torque
0	600	7	20	90	340	895	8	12	1273
0	900	9	22	135	435	985	14	40	2830
0	1200	12	28	185	730	1253	24	35	1807
10	600	10	34	92	300	1522	15	15	1557
10	900	12	34	138	450	1522	22	25	1730
10	1200	13	32	187	740	1432	28	36	1839
20	600	12	48	95	355	2148	21	17	1709
20	900	13	37	140	475	1656	24	26	1774
20	1200	15	39	190	680	1745	35	43	2161
30	600	14	70	98	440	3133	32	20	1949

30	900	14	45	142	485	2014	30	28	1883
30	1200	16	44	192	650	1969	40	45	2238

Table 20 Power and torque distribution

Required pump power and torque versus motor output power and torque calculations are shown in the graphs below.

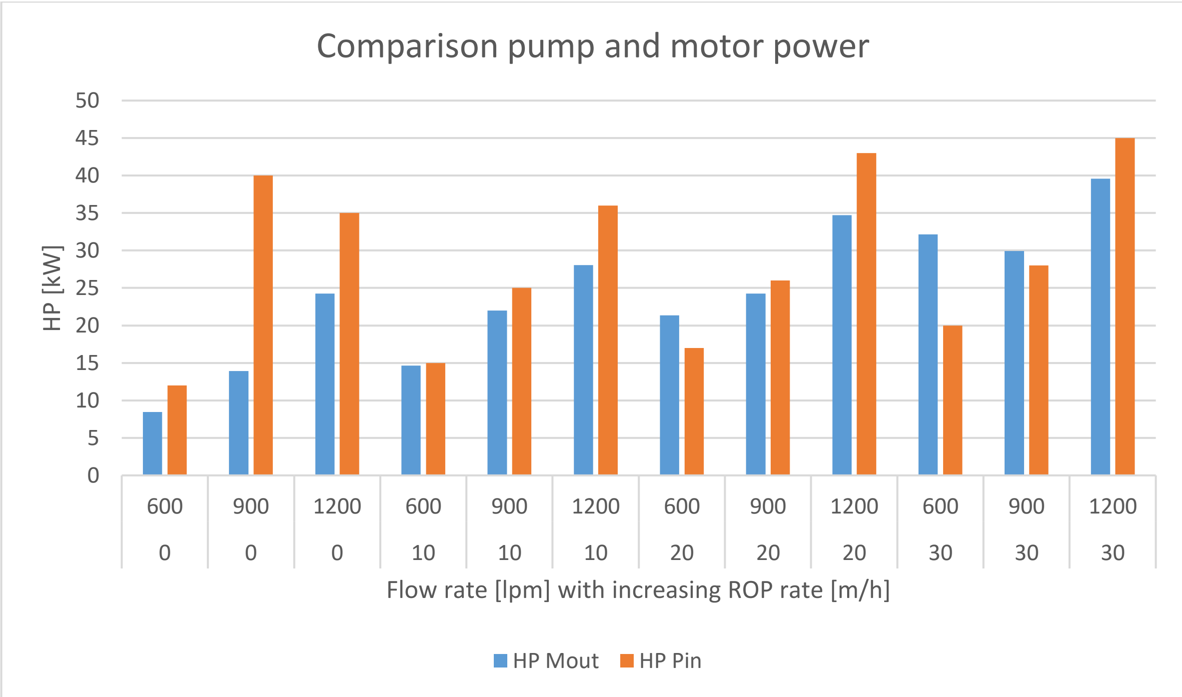


Figure 42 Comparison pump and motor power

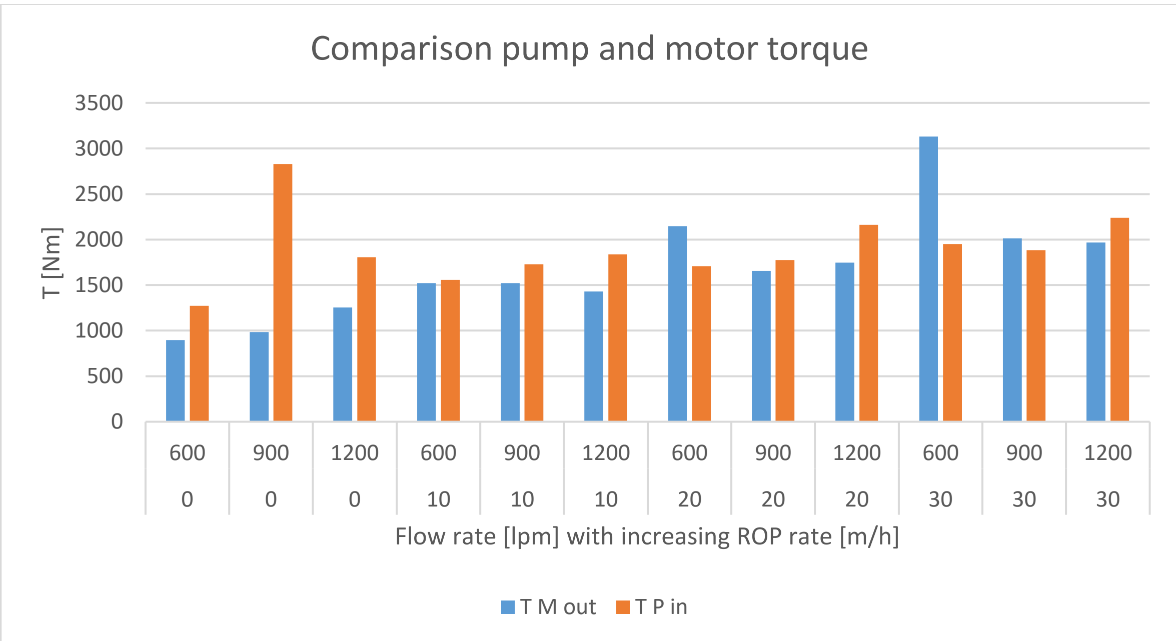


Figure 43 Comparison pump and motor torque

The table and graphs above shows that the motor-pump set will not function with the given parameters, because the input torque and power is generally too low to make the pump function. This shows that the power generated by the motor has to be increased. The power can be increased by increasing the pressure drop across the motor. The estimated pressure drop over the motor is too low.

The hydraulic and mechanic resistance for the pump is higher than the power supplied by the motor, and the motors flow restriction on the supply flow. Consequently, the motor cannot turn and the motor inlet pressure will increase. With increasing differential pressure over the motor, the torque and power also increase. A balance of power and torque between the motor and pump is found when the hydraulic and mechanical frictional forces are the same as the hydraulic input force from the topside mud pumps. As seen in the previous examples, this balance is hard to predict and is dependent upon many factors. Some of the factors are seen in the examples above, but other factors, such as the design of the pump and motor will affect their power and torque generation with differential pressures and flow and fluid parameters.

5.2.8 Mud motor bypass

Detail design of the motor and pump sets is, as mentioned earlier, considered beyond the scope of this thesis. However, the motor bypass idea should be further evaluated and the feasibility proved.

Several mud motor manufacturers offer mud motors with a bypass flow, permitting higher flow rates than recommended without a bypass. NOV, as one of them, offer several motors with multiple bypass nozzle sizes, allowing a selection of flow rates through the bypass. The bypass flow is led through the rotor, which is equipped with a nozzle. See illustration below.

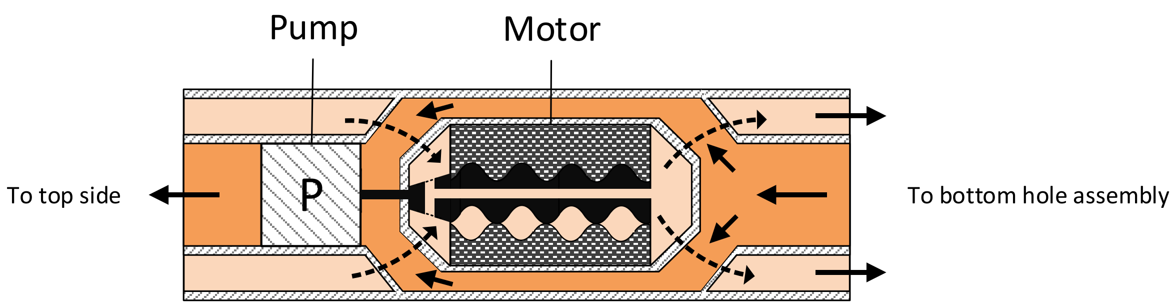


Figure 44 Motor bypass through rotor

It is important to be aware that the bypass flow will vary with the differential pressure across the motor, and the strain on the motor. For high torque conditions, the differential pressure across the motor will rise, and thus the flow in the bypass will increase. For low flow rates and low differential pressures over the motor, the flow rate in the bypass will decrease. Choosing a too large bypass nozzle will subtract too much power from the mud motor, and the system is unable to function. Choosing a too small or slightly too large nozzle, may cause mud level regulation problems.

Since the power and torque generation will suffer from the bypass flow it is recommended to find motor-pump pair which allows a minimum of flow through the bypass. The appropriate nozzle size can be calculated with a standard nozzle-flow calculation and is dependent on:

- Mud density
- Differential pressure
- Total flow rate
- Motor flow rate at given RPM[22]

Employing NOV's motor data handbook and Nozzle selection guide yields a selected nozzle size to 8/32" for the motor-pump set employed in the chapter. The Flow rate as a function of differential pressure across the nozzle is presented in the graph below. The illustration below is taken from NOV's mud motor handbook[22].

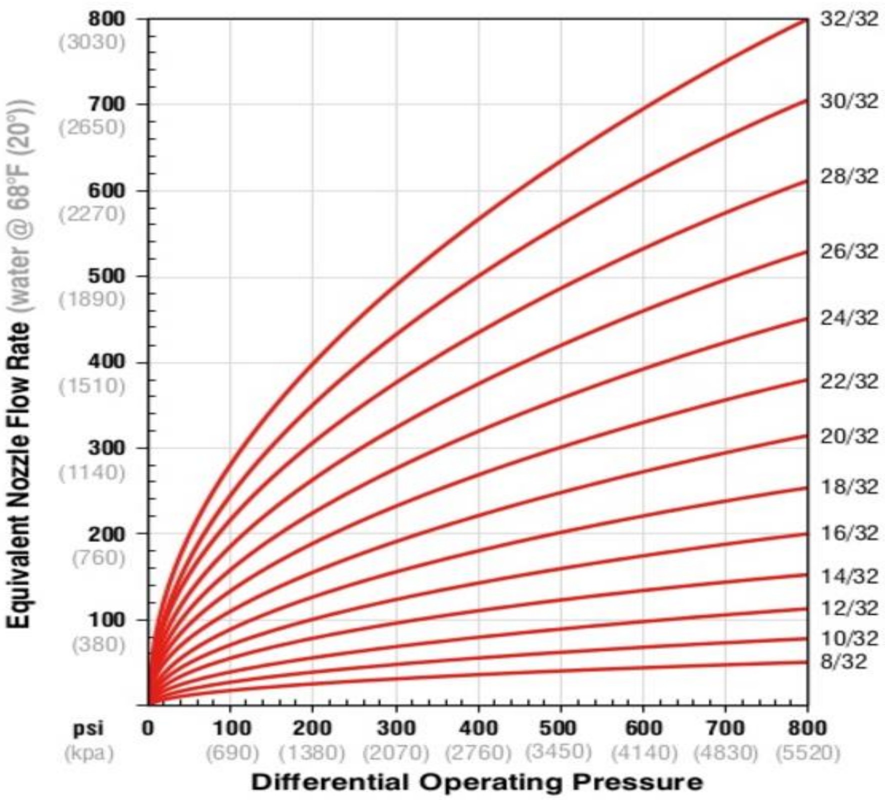


Figure 8: Nozzle sizes and equivalent flow rates for water

Figure 45 NOV nozzle size selection

If an 8/32" nozzle is selected, the equivalent nozzle flow is quite stable with variable pressure differentials. The equivalent nozzle flow can be taken to vary with around 100 lpm, from 27 to 55 bar.

5.3 Results and Discussion Level Regulation and Pressure Distribution Estimations

The solution for level regulation seems to be theoreticalfeasible. The level regulation principle is built on well proven technology. It is important that the drill bit nozzles are selected to the expected pressure drop, so that they do not restrict the flow too much, and lowers the mud motor's pressure drop.

The solution for level regulation enables level regulation within distinct limitations, changing with the variable drilling parameters. However, the level regulation solution can only adjust the level development within slow rates, for example a level rise of 0,4 meters per minute. As seen in example 3, the ROP has significant impact on the level development, and the bypass flow rate is important to be set to an optimal rate, in accordance with the expected well parameters. With the selected pump-motor set, and a bypass flow rate of roughly 200 liters per minute, the system cannot increase the mud level in the well in 100 meter water depth, and 500 meter deep well. However, the frictional pressure loss and hydrostatic pressure to be overcome by the return pump will increase with the length of the well, and the level regulation operational window will adjust accordingly. The solutions possibility to increase the level will increase with increasing well length.

The examples in chapter 5 shows the importance of pressure, torque and power distribution. Based on the evaluation above, accurate pressure and flow data can only be obtained by performing pressure estimates based on real pump and motor data. Another pressure estimation learning lesson could be to lower the efficiency of the pump and motor, to get a higher safety factor with regards to the systems operational window.

The selected pump-motor set is unable to function with the pressures taken from the pressure distribution estimation. In the selected drilling scenarios, the pump rarely gets enough power and torque from the motor to pump the return liquid up to topside. The motor needs a higher pressure drop to obtain enough torque and power to turn the pump. The pressure distribution estimation yields a little too low differential pressure over the motor to power the pump. However, the system pressure estimated does seem to obtain values within coarsely acceptable limits. There are still many parameters which have not been taken into considerations, and the motor-pump set was only selected as a theoretical experiment and may be far from an optimal solution with regards to pump and motor co-design.

The design of the pump-motor set is complex and must be done by a manufacturer of pumps or mud motors. Some of the considerations are to obtain suitable torque and power absorption and output. Other considerations for the design which needs to be considered are vibrations, resonance, run-away, loading sensitivity and start-up pressure.

6 EVALUATION OF SYSTEM BEHAVIOR

It is hard to predict the system behavior during rapid flow and pressure changes, especially for multiple pump-motor sets in series. Advanced computer software programs should be used to simulate the system behavior. Control of the pump system during rapid flow changes and pressure limits due to high water depths, are challenges that are discussed below. Several possible cases are discussed to try to identify the correct system response to irregularities.

6.1 General pump-motor behavior - Single pump system

This section describes the Single Pump Systems behavior during changes in the operation. The changes could be start-up, ramp-up or shut down of the circulation. Balances of displacement, flow, pressure, torque and power need to be established, based on changes in the system flow resistance.

As a starting point, some predictions may be drawn:

- With increased load on the return pump, implying a higher return pump discharge pressure, the load on the motor also has to be also increased, and the driving fluid pressure drop across the motor therefore has to be increased. It is assumed that the top side pressure remains quite stable, and that the increased pressure drop across the motor lowers the available pressure drop to the drill bit. Increased load on the return pump will be experienced during ramp-up of circulation flow rate and with increasing ROP.
    - With a higher pressure drop over the motor, the same pressure drop will occur over the bypass nozzle, which will result in a higher flow through the nozzle. This will affect the flow through the motor, and there will be less flow through the motor to power the pump. Reduced available power can be avoided by keeping the increased nozzle flow to a minimum. The increase or decrease in nozzle flow during operational changes should be small compared to the average nozzle flow.
- With mud flow ramp-up, the frictional forces will increase and thereby increase the required pump discharge pressure. In addition, the available pressure drop over the motor will be reduced. This can to some extend be compensated by increased pressure from the top side mud pumps. However, higher displacement and pressure drop of the motor, produces more power output to the pump.
    - The increased frictional pressure loss with increasing flow rates or pipe length can set the limitation of the system. With too high flow rates, and frictional pressure losses, the differential pressure over the drill bit nozzles is too low. The added hydrostatic pressure to be overcome by the pump is increased with deeper waters, well length and increasing densities. With increasing water depths, the well length gets more and

more restricted. The frictional and hydrostatic pressure to be overcome by the return pump, together with decreasing available pressure drop for the motor dictates the limits for the operational window of the system.

Flow ramp-up:

- With supply mud flow ramp-up the RPM of the motor and pump increases, the return flow rate increase. The pump experiences higher loads due to rising frictional forces in the return conduit, which in turn strains the motor until the differential pressure over the motor increases to balance the pumps required power input.

Increase of ROP:

- With increasing ROP the load on the pump will increase, due to increased volume and density in the return conduit. This causes the pump to restrain the motor until the differential pressure over the motor increases to balance the pump strain.

Decrease of ROP or flow rate:

- With lowered pump load, the required power from the motor is reduced, and the motor will then rotate more freely, and require a lower differential pressure.
    - Due to the lower differential pressure over the motor the flow through the bypass nozzle will decrease.
- During mud flow ramp-down, the pump experiences lower load, the differential pressure over the motor is decreased.

Pump wear:

- During drilling and pumping of fluid with high cutting contents, the stator-rotor interface will experience wear. This can result in higher slip and lower pressure and flow capacity. The efficiency of the pump may be lowered. The load on the motor may decrease at the same RPM with small pump wear.
    - The RPM of the unit will increase to obtain the same flow and the load is maintained quite like before, but with increased wear the efficiency of the pump will degraded and there will be increased load on the motor, with the same pump displacement.

Starting of circulation:

During start-up after circulation stops there are several flow suppressing forces to be overcome, before the system is operational:

-Gel strength -Pump and motor inertial and frictional forces -Opening pressure of the DSV

-Hydrostatic pressure in return pipe

- As mentioned earlier, the pressure to start circulation in the system is higher than the pressure at low circulation speed. A pressure-peak is expected during start-up.
- During start-up, the topside mud pumps build up pressure in the supply line. Once the differential pressure over the DSV is high enough there will be flow in the annulus conduit. The flow through the nozzles will cause a pressure drop over the motor, which in turn, with enough torque and power, will start to rotate and thereby start the return flow.
- There might be a mud level increase in the well during start-up.

6.2 Multiple pump-motor sets in series

For multiple pump-motor sets in the DDS, the co-functioning of the motor-pump sets in the drill string must be evaluated.

The pressure distribution of the supply fluid depends on the resistance of the motors and other factors like static head and frictional losses. The resistance in the motors may vary from motor to motor, depending on operational irregularities and is hard to predict. For instance, it is expected that the lowest pump in the well will be subject to increased wear compared to the pumps above. This is since the largest cutting parts can be expected to be grinded somewhat in the first pump, and less in the subsequent pumps.

Some predictions may be drawn for the Multiple Pump System:

- With increasing wear of the lowest pump, the slip will increase and the displacement and discharge pressure will decrease. This gives a lower load on the motor.
- With reduced displacement through the first pump, the load on the subsequent pump may rise, causing increased torque and power demand on the adjacent mud motor.
- The increased torque and power demand on the mud motor yields a higher differential pressure over the motor. causing higher flow through the motor bypass.

Starting of circulation:

The start-up flow suppressive forces are almost the same as for the Single Pump System. However, there are now four motor and pumps which have a starting torque and pressure. During the selection of number of motor-pump sets in the Multiple Pump System, the start-up torque of the pumps, and the starting pressure drop in the motors needs to be considered, to avoid a too high starting pressure.

- As mentioned earlier, the pressure to start circulation in the system is higher than that of circulation with low speeds, and a pressure-peak is expected during start-up.
- During start-up, the topside mud pumps build up pressure in the supply line. The pressure will increase through the bypass nozzles and annulus to the DSV. Once the pressure reaches the opening pressure of the DSV, the DSV is assumed to open slowly. The pressure between the DSV and the lowest motor will decrease rapidly, and the DSV opening may decrease. This may be repeated some times over, due to the flow restriction in the bypass nozzles. But with increasing flow through the annulus, there should be a build-up of pressure differentials over the motors. And finally, the motors and pumps will start to rotate.
- There might be a level increase in the well during start-up.

Flow ramp-up:

- With flow ramp-up the RPM of the motors will increase and the pumps experience higher loads due to rising frictional forces. The differential pressures over the motors increase to balance the pumps required power input.

Increase of ROP:

- With increasing ROP rates the load on the pumps will increase, due to a higher density in the return conduit. The load on the motors increase, and the differential pressures over the motors increase. This may happen with the following scenario:
    - The lowest pumps backpressure increases first. The pressure drop over the lowest motor increases. When the cuttings pass the second lowest pump the backpressure for this pump increases, and the associated motor pressure drop increases. This continues throughout the system.

Decrease of ROP or flow rate:

- With lower pump loads, the load on the motors are lowered. The motors need a lower differential pressure.
    - Due to the lower differential pressures over the motors, the flow through the bypass nozzles will decrease.
- During flow ramp-down, the pump experiences lower load, the differential pressure over the motor is decreased.

Pump wear:

- The Lowest pump may be subjected to higher wear than the subsequent pumps. If this should happen, then the displacement and discharge pressure of the lowest pump will decrease. Decreased discharge pressure causes the subsequent pumps to work under higher loads. The associated motor differential pressures increase.

6.3 Spud in

During the spud in drilling of a new well, there might be a small discharge of drilling fluid. This is because the return inlet channels are set above the BHA and motor, and can only pump up sea water until the inlet channels are submerged in the drilling mud. However, if the THLT is designed high or large enough, the drilling discharge fluid can be contained in the THLT until the returning fluid is mud. Another possibility to avoid the mud discharge during start up is by employing a crossover at top side, and starting the drilling with sea water.

7 RESULTS OF THE DEVELOPED SYSTEMS

7.1 The developed systems drilling capacity

The drilling capacity of both the developed systems are the same, assuming the motor-pump sets of both systems have the same efficiency. The requirements stated in the start phase of the system development, was that the system should be able to drill a 500 meter deep top hole, in 1000 meter water depth. The starting diameter size was set to 36”, required drilled 100 meter deep, and the following 400 meter was to be drilled with a 26” drill bit. Whether the developed system can manage these requirements is a question of minimum required HSI, drill bit pressure drop and mud flow rate. Setting the minimum required values to what Reelwell has demonstrated good hole cleaning with, the minimum required pressure drop is 60 bar, and the minimum required HSI is set to 0,85 kW/in^2.[13, 15] The required HSI, flow rate and drill bit pressure drop will vary with the top hole to be drilled.

7.1.1 Water depth and well length

The table below shows the estimated differential pressure over the drill bit nozzles with increasing water depth and well length. The flow rate is set to 900 liters per minute, the density of the supply mud to 1100 kg/m^3, and the cutting contents to 5%. The pressure unity is bar and the values above 80 bar are marked with green, the pressures between 60 and 80 bars with yellow, and the lower pressures are marked with red.

Water depth [m]	**1500**						
	1250	52					
	1000	89	56	26			
	750	111	92	59	29		
	500	143	114	95	62	32	
	250	165	146	117	98	65	35
	100	180	161	136	113	84	54
	0	**500**	**750**	**1000**	**1250**	**1500**	**1750**
	Well depth [m]						

Table 21 Differential pressure drill bit nozzles with increasing water depth and well length

Table 24 below, illustrates the HSI for the same well parameters as the table above, unit horsepower per square inch.. The drill bit diameter is taken to 26”. All values are red, indicating a HSI lower than 0,85kW/in^2. The system never obtains high enough HSI for drilling with 26”. The values are even lower for drilling with a 36” drill bit.

Water depth [m]	**1500**						
	1250	0,20					
	1000	0,34	0,21	0,10			
	750	0,42	0,35	0,22	0,11		
	500	0,54	0,43	0,36	0,23	0,12	
	250	0,63	0,55	0,44	0,37	0,25	0,13
	100	0,68	0,61	0,52	0,43	0,32	0,20
	0	**500**	**750**	**1000**	**1250**	**1500**	**1750**
	Well depth [m]						

Table 22 HSI of 26" drill bit with increasing water depth and well length

The operational window of both systems are limited due to required motor pressure drop to power the return pump. The pressure losses in the annulus subtracts from input pressure and the available pressure to power the mud motor and the drill bit nozzles is lowered. The frictional pressure loss in the pipe and annulus of the DDS, and the hydrostatic differential pressure over the inner pipe are the main loss contributors. This implies that the longest wells the systems are capable of drilling, are in shallow waters, with low cutting contents in the return pipe.

The graphs below show the estimated differential pressures over the bit, with increasing well length for variable flow rates and cutting contents in 250 meter water depth. Drilling with high flow rate and cutting contents means that the ROP is high, such operational conditions lead to high backpressure to the return pump, and the operational window is restricted.

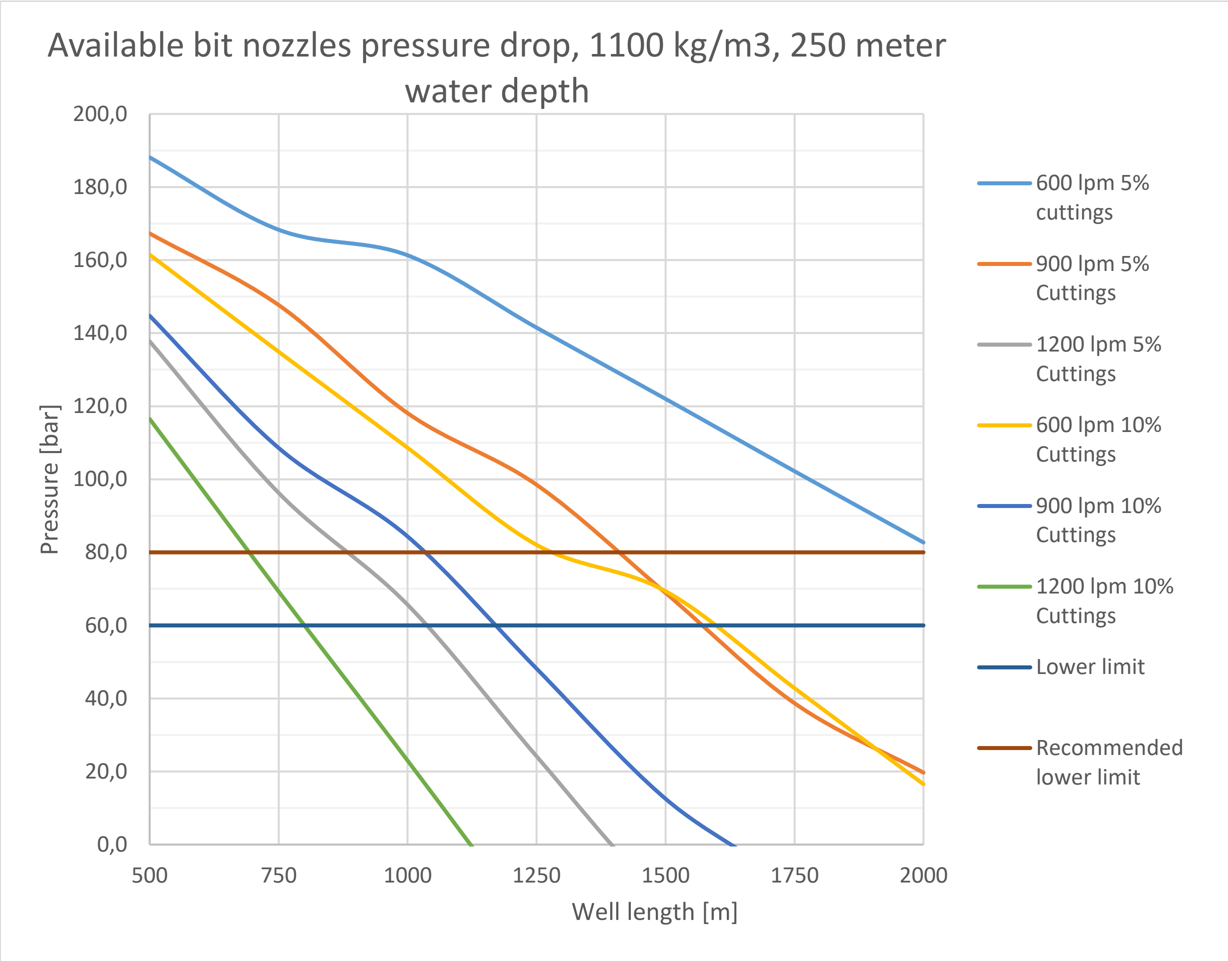


Figure 46 Bit differential pressure with variable flow rates and cutting contents

7.1.2 Rate of Penetration

The results for the maximal ROP, is obtained by setting a maximum allowable cutting contents limit. This limit is not absolute and could be passed for short durations of time. A limit for maximum cutting contents in the DDS is selected to 15% The maximal average ROP with variable flow rates are shown below.

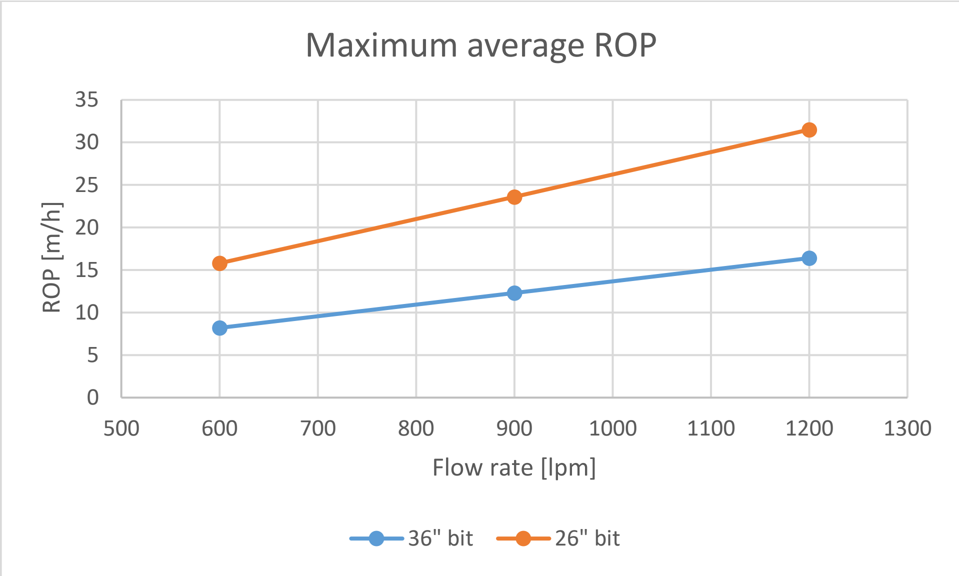


Figure 47 Maximum average ROP

7.2 Single pump system

The requirements for the pump in the Single Pump Systems needs to be highlighted to be able to discuss whether the requirements are feasible for a PC pump and mud motor. The flow rate capacity is set to the same as the maximum flow rate of the DDS. The lift capacity depends on the parameters for the top hole to be drilled; Water depth, well depth and length, desired mud density and viscosity and drill bit size and expected ROP.

7.2.1 Pump requirements

The required pressure lift capacity of the return pump for variable water depths, well length/depth with a density of 1100 kg/m^3, 900 liter per minute flow and 5% cutting contents are illustrated in the figure below.

The starting base case, of 1000 meter water depth and 500 meter well length yields a required pump pressure capacity of around 75 bar. The hydraulic power output of the pump should be around 107 kW.

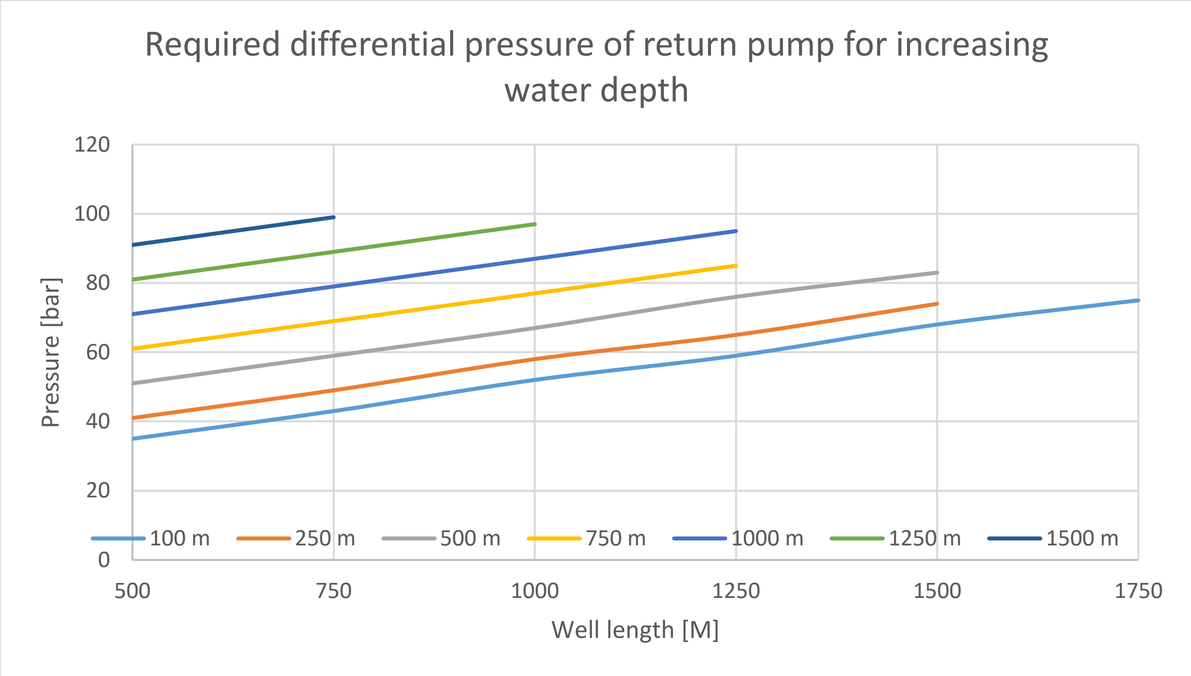


Figure 48 Required differential pressure over return pump with increasing water depth and well length

7.2.2 Motor requirements

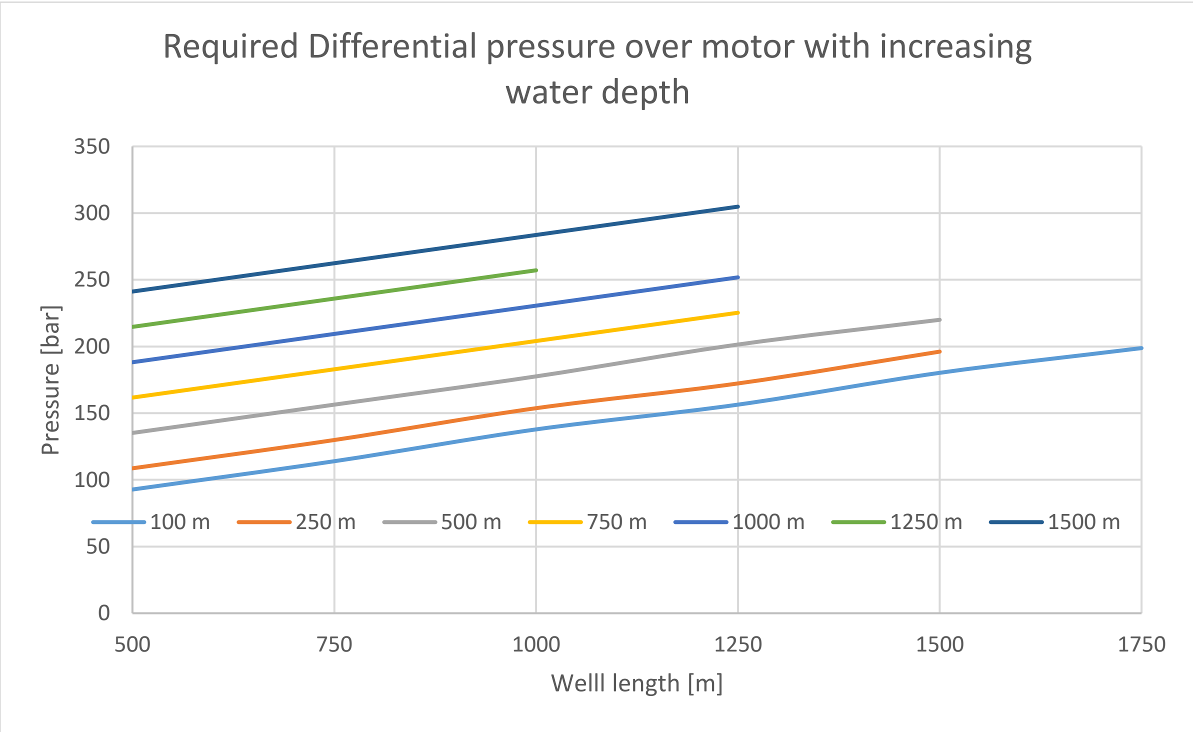


Figure 49 Required differential pressure over motor with increasing water depth

The figure above shows the estimated differential pressure over the motor with increasing well length for variable water depths. The flow rate is set to 900 lpm and the density is 1100 kg/m^3 and the cutting contents in the returning fluid is 5%.

For the base case the required motor capacity is set to 1000 liter per minute and 200 bar. The torque and power requirements needs to be set according to the employed pump and motor. But the motor should roughly produce 150 kW to drive the pump, with a pressure drop of roughly 240 bar.

7.3 Multiple Pump System

The hole goal of the multiple pump system is to be able to lower the required motor and pump differential pressure to what is obtainable with regards to design limitations.

7.3.1 Pump requirements

The starting base case, of 1000 meter water depth and 500 meter well length now yields a required pump pressure capacity of around 20 bar. The hydraulic power output of each pump should be 29kW.

The required pressure lift capacity of return pumps in the multiple pump system, configurated with four pumps, are illustrated in the figure below. The density is set to 1100 kg/m^3, the flow rate is 900 liters per minute and the cutting contents is 5%.

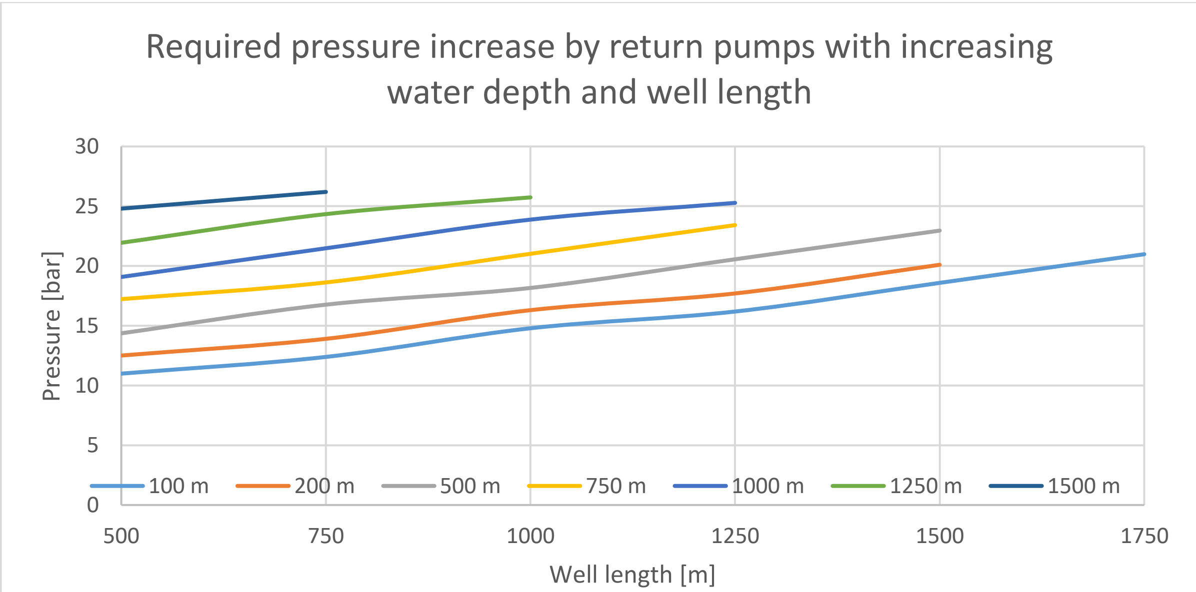


Figure 50 Required pressure increase by return pumps with increasing water depth and well length

7.3.2 Motor requirements

For the base case the estimated differential pressure over each motor, with four sets in series, 378,5 meters apart, is taken to 55 bar. The required power output to drive the associated pump, should be around 40 kW.

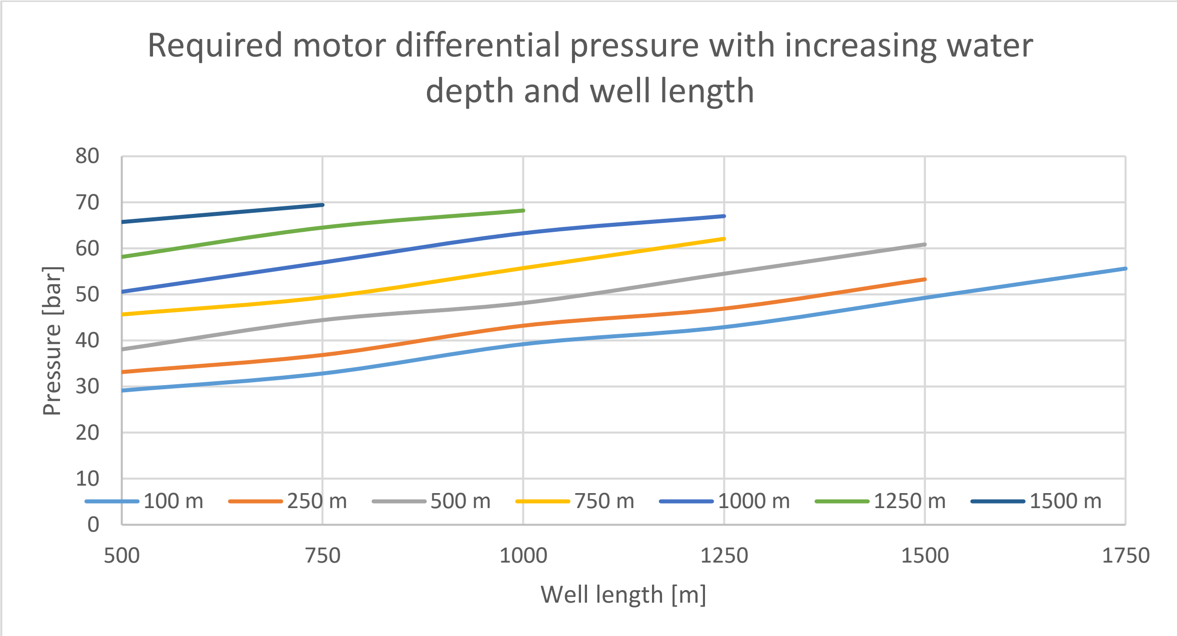


Figure 51 Required motor differential pressure with increasing water depth and well length

7.4 Uncertainties

7.4.1 Estimation of pressure distribution with regards to operational drilling capacity

The input pressure from the top side mud pumps was set to 320 bar, during the estimation of the pressure distribution. This number was set to avoid exceeding the maximum working pressure of the pipe. However, there are uncertainties with regards to the real pressure distribution and development in the system. Two of the reasons for this uncertainty are described below.

1. The pressure drop in the motor/s are estimated only based on the efficiency of the motor and pump. And in section 5.2.6 describing the power and torque of the motor and pump, the predicted pressure drop over the motor was too low for the applied motor-pump set. It is uncertain if a motor-pump set would require more than the estimated pressure drop even though the pump-motor set is co-designed for the well planned to be drilled.
2. During the estimations of the pressure distributions within the systems, it is assumed that the pressure drop in the drill bit nozzles will adjust to the available pressure drop, after the frictional pressure drop and the pressure drop in the motor/s has been subtracted. At least as long as there is more than 60 bar still available for the drill bit pressure drop. This may have been a too simple assumption to have been made. It is uncertain if there should have been estimated a higher required pressure drop over the drill bit nozzles. If this is the case, then the systems drilling capacity will be reduced even further.

7.4.2 Co-function with several motor-pump sets in series

There are uncertainties with regards to the co-functioning of several motor-pump sets in series. It is not recommended to place several PC pumps in series, since they are positive displacement pumps, and uneven flow and pressure build-up might cause premature wear. Also, since the power supply to the pumps is not directly controlled, and the bypass nozzle open for uneven power distribution, it is hard to predict the actual behavior of the multiple pump system.

8 DISCUSSION ON THE DEVELOPED SYSTEMS AND THE POSSIBILITY FOR A FULL RETURN TOP HOLE DRILLING SYSTEM

8.1 Discussion of the developed systems drilling capacity

8.1.1 The Dual Drill Pipe

The DDS chosen for the developed systems is found to be a limiting factor to the systems drilling capacity. The low maximum flow rate and the related frictional pressure loss restricts the accomplishable hydraulic horsepower at the drill bit nozzles. Also, the maximum ROP is restricted due to high cutting contents in the return pipe, due to large drill bit sizes in top hole drilling and thereby high cutting accumulation while drilling. If a DDS with increased pressure and flow capacity was employed, this would lower the cutting contents in the return conduit due to increased flow, and enable higher HSI and drill bit differential pressure.

8.1.2 Pump power source

During the development of the systems, it was chosen to select a mud motor to power the return pump. This choice led to strong limitations of the system, but was set on the desire to base the system on existing technology, avoiding extensive development of new equipment, such as an electric conducting DDS. This also made level regulation complicated. Since the DDS is argued to be a limited factor for top hole drilling, and it would be better to employ a DDS with a higher flow capacity, perhaps the inclusion of an electrical conduct in the larger DDS would not imply too much engineering after all. With an electrical conducting DDS, the limitations set by the drill bit differential pressure and HSI would not be an issue any more. Top holes could have been drilled much longer and in much deeper water depths. There would be no issue with level regulation and the flow rate could have been adapted to the best drilling parameters. The training of personnel with regards to drilling with a new system would also have been simplified. The pump options would have been expanded due to an electro motor's ability to produce high torque and power with both high and low RPM.

Equipment in the BHA, implying additional pressure drop before the drill bit nozzles will shorten the possible well length to be drilled, and water depth the system can function in. The employment of a mud motor to power the drill bit can be removed all together, depending on the top hole parameters, and the desired drilling parameters. This is unfortunate, but the drilling may still be accomplishable.

The selected mud motor to power the return pump in the Single Pump System and the multiple pump-motor sets in the Multiple Pump System, might degrade the signals sent through the mud with regards to Measure While Drilling, MWD. MWD is not always performed on top holes and the technology is on the edge of the scope of the thesis. But there are several possibilities enabling the signals from the

MWD equipment to be received top side, in spite of the mud motors. The use of repeaters, repeating and amplifying the signals could be an option. Otherwise, the use of electromagnetic impulses through the pipe could be an option.

8.1.3 Level regulation possible solutions

The level regulation solution developed was complex, and led to lower hydraulic power supply to the mud motor, compared with the other level regulation solution, requiring a filling line. The flow rate would have to be adjusted to the level development, rather than to optimize the drilling. The level regulation solution would also require training of the involved personnel. However, the other solution, with a filling line, also has its disadvantages. The extra filling line and connection to top side facilities, would have been two of the disadvantages, as they would degrade the easy setup and deployment of the system. With regards to RMR, one of the benefits for the developed systems was the elimination of hoses or umbilicals to be deployed and connected subsea.

Another concern with the selected level regulation is the no longer option of pumping down high weight mud in case of unstable well conditions, without stopping the return pump. If necessary, the return fluid could be choked in the FCU, but this would also restrict the supply fluid. If an uncontrolled drilling condition occurred, how could the well be balanced or stabilized? What would be the most beneficial measures? These questions are considered beyond the scope of the thesis, but needs to be answered if the development was to be further analyzed.

During the development of the system, the possibility for equipment controlled from top side by radio communication was restricted. This was done to avoid poor signal transmitting during drilling, to degrade the drilling parameters, by requiring circulation ramp-down to transmit signals. However, such equipment would simplify the mud level regulation in the well. A valve opening and closing on command from top side, could increase the mud level in the well, by a dump line from downstream the return pump. With a gear between motor and pump adjusting on radio signals from top side, the return pump could have been disabled from the motor if necessary. Perhaps an “emergency disconnect gear” between the motor and pump could enable normal well kill pumping from top side during uncontrolled well situations. This possibility is not examined further. It is assumed that there are several unknown innovative solutions, which could simplify and improve the level regulation of the system. But the selected level solution has a low grade of innovation regarding new equipment, and this may be positive for the expected reliability.

8.1.4 The Top Hole Level Tank

The deployment and reliability of the top hole level tank is also an issue of concern. Could the THLT be set stable and reliable to the sea floor? Perhaps a better solution would have been to employ the CAN-ductor technology, by NeoDrill, but redesigned to include a level regulation tank. The CAN-ductor technology is basically a large can, which is set into the seafloor by suction. The picture below is taken from NeoDrill's web page. The CAN-ductor can be set by a smaller vessel before the drilling rig arrives, and therefore lower cost and time spent deploying the THLT. The picture is taken from NeoDrill's web page [24].

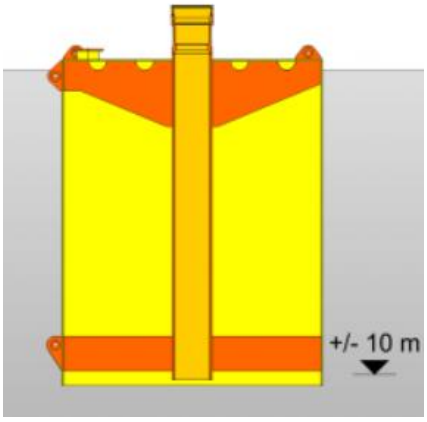


Figure 52 CAN-ductor, NeoDrill AS

8.2 Measurement of drilling capacity

The drilling capacity is set with regards to the hydraulic power per square inch, and pressure drop at the drill bit, and the cutting contents in the return fluid.

During the estimation, the highest amount of cuttings is set to 10%, but this is not set as an absolute and unexceedable limit. The percent cutting in the return fluid may be exceeded for a short duration of time. The load on the return pump, its pressure capacity and the reduced pressure to the drill bit, dictates the maximum cutting contents. If too much cuttings are accumulated, the pump might stall, due to a too high back pressure.

The hydraulic power and pressure drop at the drill bit is often used in optimization of drilling hydraulics. However, the necessary HSI and differential pressure will vary with the top hole parameters, such as soil type, depth, pressure, temperature, and also drill bit design and desired ROP. The limits set in the Results chapter referrers to Reelwells earlier experiences and may not be a good match for top hole drilling. The HSI for the 36" hole is not shown in a table in the results chapter, this is due to the assumption that since the hole length is small, and the sediments often are loose for the top layers, the HSI would not be a beneficial measure point for the drilling capacity of the system.

8.3 Drilling capacity of the developed system

As shown in the Results chapter, there is no possibility to obtain a high enough differential pressure or flow rate to gain high enough hydraulic power at the drill bit. Especially for the spud in drilling, assumed drilled with a 36 inch drill bit. This means that the washing of the drill bit, and jetting of the formation is reduced. While drilling through clay stone or shale the bit could get balled up, leading to low ROP.

The results for the drilling capacity for the developed system shows that the operational window of both systems are limited. However, within this limitation, many top holes on the Norwegian sector could have been drilled with the developed systems. The drilling capacity is reduced because of the low flow rate of the DDS. With a higher flow and increased pressure capacity dual drill pipe, the systems drilling capacity would have been increased.

8.4 Comparison to RMR and MRR

To highlight the developed systems pros and cons, a comparison to the existing full return top hole drilling systems is presented.

The obvious differences between the RMR and MRR systems and the developed systems, are the different flow path and system functionality. The RMR and MRR systems have higher flow rate capabilities, well length capabilities and water depth capabilities. This enables higher HSI, differential pressure at drill bit and the maximum cutting contents is dictated by the subsea pump and hoses.

The advantages Enhanced drilling advertise their system with, are compared to the expected advantages by the developed system in the table below.

RMR advantages, taken from Enhanced drilling web site:[5]	**Developed systems comparison**
Primary well control before BOP riser is installed	Since the developed systems enables the use of high performing mud, it is considered to have the same benefit with regards to well control. The RMR system has the same open hole as the developed systems.
Ability to check for shallow-hazard influx without a pilot hole	Level increase in the THLT would be discovered on the same base as with RMR's Suction Module. The flow rate is measured in the FCU, as with RMR's subsea pump module. Any other means RMR employ to check for shallow-hazard influx are unknown, and the same advantage is expected with the developed systems. In addition, comes the short duration for cuttings to flow to top side, opening the

	possibility for short delay formation and mud evaluation.
Improved hole stability	The same advantage is expected with the developed system. The only difference might be lacking mud cake packing of the hole walls, due to a short hole flow length. Mud packing of hole walls may help to avoid influx from the sediments, and may help to stabilize loose sediments. However, this issue is regarded as beyond the scope of the thesis, and should be considered by someone with better geology knowledge. The geological factors will wary and will dictate if this issue is applicable for the planned top hole.
Deeper surface casing ***Fewer casing strings***	This may be also be expected for the developed systems in shallow waters, but not in deep waters. With an electrical conducting DDS and an electrical pump, or with a larger DDS, the same could have been expected by employing a DDS with an integrated pump in deeper waters.
Top-hole mud log data and cuttings ***Zero discharge at seabed***	The same advantages are expected for the developed systems.
Safe identification of gas	The indication of gas in the RMR system, is presumed to be in the subsea pump module and with visual surveillance of the suction module. For the developed system, the advantages would be similar, but gas in the inner pipe, might not get identified before it entered top side facilities. It is unknown how the system would able circulation of gas out of the system. The FCU could be coupled to a high pressure flare boom, capable of burning of unwanted gas. Further

	discussion on this topic depends on the top side facilities.
Better conductor/Xmas tree stability ***Mud volume control in surface hole*** ***Fast gain/loss indication*** ***Real-time visual monitoring of the well*** ***No smothering of sea bed by cuttings*** ***Lower risk of undermining well template***	The same advantages are expected with the developed system and a system with an electrical conducting DDS and an electrical pump.
RMR disadvantages:	**The developed system comparison:**
The deployment of equipment through the splash zone has caused delays in operations.	With the developed systems, there are no hoses to be deployed. If the THLT is set on a spud base then there would be no additional equipment to be deployed at all.
Currents and poor visibility may cause delays and problems with the subsea hook-ups of umbilical and the flow lines/hoses. **The dependence on ROV is also considered a weakness to the two systems.**	The developed systems are not dependent upon subsea hook-ups, and should be independent of additional ROV services.

Table 23 Comparison of developed systems to RMR

8.5 Progressive Cavity Pump Design Limitations

The pressure capacity of PC pumps is high, but it is limited with increased flow rates. This is due to manufacturing and operational difficulties of the rotor.

The development of PC pumps has expanded, and the stator-rotor interface come in many design and material compositions. Traditionally it was common to assume a maximal of 5 bar per stage. Nowadays this limit has expanded, but the wear of the pump is increased with a tighter rotor - stator interface. With increasing flow range the size of the pump is increased and the forces acting on the rotor is increased. If manufacturing of the rotor is obtainable, for horizontal pumps the rotor may sag in the middle, resulting in too much interference with the stator. It is uncertain if the rotor will sag in any way with a vertical pump, perhaps the top section will be the most exposed section, due to tensional loadings.

During development of the systems, effort was made to try to find a suitable PC pump, capable of a flow of 1200 liter per minute and a discharge pressure within desirable limits. However, this was not succeeded, and the highest pressure capacity found was 24 bar. This may be due to several reasons:

- No need or demand for a PC pump with these flow and pressure capacity requirements
- Several pumps in parallel can produce enough flow rate combined
- The design of a PC pump with these capacities would be very expensive

It may be possible to design a PC pump with the desirable capacities, due to the possibility to widen the rotor and stator, and the overall diameter of the pump. As long as the system is intended for top hole drilling, then the outer diameter of the pump and supply conduit could be increased to around 20 inches. This would allow the design of a larger rotor with a higher strength capacity. The supply conduit could possibly be led inside a wide rotor, allowing a maximal diameter of the pump.

If the design of a PC pump, with the required pressure capacity of minimum 75 bar would prove to be impossible, then the other pump options needs to be reconsidered. However, since the power source is limited to a mud motor, and a gear entails undesirable losses, the pump should function on speeds.

8.6 Effects on cost and time

Only a brief discussion of effects on time and cost are made.

The setup and the deployment of the developed system is considered to have minimal effect on schedule. The DDS is handled as a standard drill pipe, and the motor-pump sets are assumed to be assembled to the drill pipe with threaded connections. The FCU and TDA can be quickly installed before rig skidding and drilling starts.

The THLT is assumed to be able to be deployed on a spud base, like RMR can set their SMO on.

The ROP capacity may be a schedule delaying factor compared to RMR and conventional “drill and dump”. Connection stops may also be prolonged, as there are uncertainties with regards to circulation start-up and ramp-up, especially for the Multiple Pump System.

The design of the motor-pump sets, the development of an operational control system and the design of the THLT is a one-time investment. When drilling top holes on new drilling rigs, the personnel would need training. This is necessary every time the system is utilized on a a new drilling rig.

The expected cost savers compared to conventional drilling is:

- The elimination of pilot hole
- Stable top hole drilling in geologically challenging areas (lower risk for well abandonment)

- Lower risk for cleaning/ jetting jobs, due to undermined template.

However, if there are no geological, environmental or statutory reasons for drilling the top holes with full return, then it would not be economically advantageous to employ the developed systems. This is due to increased costs with regards to:

- Treatment and disposal of cuttings
- Mud costs
- Possibly prolonged drilling, due to low ROP.

8.7 Learning points

Remotely controlled equipment would have simplified the system development. This was excluded during the system development, due to the impression that this was not a technologically existing or reliable possibility. The remote-controlled equipment would have had to be powered by a battery, communicating with top side by radio signals or other signals.

Another solution for the level regulation could have been to employ a dump line from downstream the return pump (but upstream the check valve). This way the mud motor would have been powered by all the supply mud, and reducing the necessary pressure drop to obtain enough power to drive the return pump. This option was not seen during the analysis of the possible solutions for the system. However, this would also subtract power from the system, by increasing the flow rate of the same amount as for the motor bypass.

During the evaluation of the DDS, it was decided to analyze the possibilities for a full return system with the available DDS, even though it was clear that desirable values for HSI not could be accomplished. This decision led to development of a system, with string limitations. It would have been beneficial to highlight the possibilities for a system with a larger DDS with a higher flow capacity. However, it is still a string argument that it would be large design project to develop a larger DDS, and perhaps for small benefits. And, if a large redesign of the DDS would take place, it would perhaps be more beneficial to include an electrical conductor instead of increasing the flow capacity.

During the course of the thesis writing, it became clear that a higher drilling technology knowledge would have been desirable. The lack of knowledge within drilling equipment and drilling operations may have had a degrading effect on the thesis, but high effort was made to obtain knowledge on the applicable subjects.

9 SUMMARY AND CONCLUSIONS

The thesis developed, and theoretically proved feasible, a solution for regulating the mud level in the well. This is an important finding, which enables a full return top hole drilling system, within the limitations of existing technology.

However, due to the chosen pump power source to be a mud motor, the level regulation solution became complex, with several challenges to be solved. The solution required the mud supply flow rate to be adjusted to the level control, rather than to be used to optimize the drilling parameters. Also, the possibility to pump down heavy mud with a high flow rate to gain control in an uncontrolled well integrity situation was removed, without the use of remotely operated down hole equipment.

The chosen pump type is a progressive cavity pump, and its limitations represent an uncertainty. It is uncertain if it is possible to design a PC pump with the necessary flow rate and pressure capacity. To account for this, a second system was developed, with several pump-motor sets in series in the drill string. The system behavior with multiple pump-motor sets represent an uncertainty, but it is assumed that the system would function as intended.

The thesis concludes that a dual drill pipe with a higher flow and increased pressure capacity must be developed, to obtain comparable drilling capabilities to normal “drill and dump” and innovative full return top hole drilling. The selected dual drill string proved to be too small to accomplish comparable drilling capabilities for the base case. The base case was 1000 meter water depth, 500 meter deep top hole, with 100 meter deep 36” hole and 400 meter 26” hole. The selected dual drill string gives a too low flow rate to remove the cuttings generated with a top hole size drill bit and normal ROP. Also, the available hydraulic horsepowers at the drill bit nozzles are too low. Even though the pressure drop over the drill bit nozzles is in excess of 80 bar, a too low horsepower per square inch value is obtained, due to the low flow rate in combination with the large drill bit diameter.

The thesis concludes that a full return top hole drilling system applying a concentric dual drill string and an integrated pump is feasible. The developed systems have easy deployment and have comparative advantages over other existing full return top hole drilling systems. The costs of the developed systems are also comparative to other full return top hole drilling systems, but not to normal “drill and dump” top hole drilling.

For further development, a larger and electrically cabled dual drill string would offer significantly better possibilities. Eliminating the mud motor to power the return pump, would give significantly larger hydraulic horsepowers per square inch and pressure drop at the drill bit nozzles.

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