POLITECNICO DI TORINO

Department of Environment, Land and Infrastructure Engineering

Master of Science in Petroleum Engineering

Drilling Approach Selection Scheme (DASS) for Managed Pressure Drilling Techniques

Supervisors:

Prof. Raffaele ROMAGNOLI	Politecnico Di Torino
Mr. Angelo CALDERONI	DRILLMEC S.p.A
Mr. Francesco COLAIANNI	DRILLMEC S.p.A

Candidate

Ahmed Fawzy Ibrahim Elrefai

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ABSTRACT

Conventional and overbalance well drilling practices have been always the main style to reach energy and hydrocarbon resources underground. But as time advances, the conventional energy resources in conventional settings are becoming scarcer. That makes reaching new energy resources a challenging job using conventional ways of drilling. In other words, more resources will be needed to explore deeper in the earth in reduced tolerability, and strict conditions (e.g., Narrow Formation pressure/Fracture pressure window).

These strict conditions will need more than the conventional drilling approaches in order to pass through them safely and optimally. That was the rising argument of unconventional drilling techniques as Under Balance Drilling (UBD) and Managed Pressure Drilling (MPD) Techniques. Managed pressure Drilling (MPD), had acknowledged much of attention in past years. The market trends show an increasing interest in using it day after day.

The main objective of MPD systems is to provide more tools and methods that would help in controlling downhole pressure within a narrow window between formation and fracture pressures without compromising Health, Safety and Environment (HSE) Values.

MPD systems are adding to the value of the well by reducing time and cost, but also they require special considerations (e.g., Rig Modifications, more equipment, higher experience levels….etc.) when utilized. These considerations makes the drilling process more complex.

Benjamin Franklin once said "*An investment in knowledge pays the best interest*.". That can be applied in well planning phase, by making sure to have a complete understanding of the well situation and conditions to decide the optimum approaches, equipment, and experience level needed in order to develop a vigorous drilling plan.

This research aims to develop a fast yet robust well screening criteria for the most used and widespread MPD technique 'Constant Bottom Hole Pressure (CBHP)'.

The study led to the development of 'Drilling Approach Selection Scheme - DASS'. DASS provides an understanding of different drilling parameters and operations, and their effect on downhole pressure. Moreover, DASS provides an understanding of the benefits on CBHP MPD systems utilization.

DASS involves two interconnected steps. The first is to perform hydraulic calculations and sensitivity analysis of drilling parameters (e.g., Rheological model, Surge/swab,….etc.) with respect to API recommended practices "API RP 13D" using a visual basic based software. The second step, is to provide a judgment and decision making scheme that yields the best drilling approach to be applied, depending on the hydraulic calculations and underground geological and pressure parameters. DASS had been applied to a narrow pressure window conditions for a well in Darquain field in Iran, showing that CBHP MPD techniques will be useful if applied in such well conditions, unlike the conventional drilling, which will not be applicable.

DEDICATION

I dedicate all of this work specially to **my mother and family** , who were always encouraging and supporting me towards success and superiority in life.

Moreover, this work is directed and dedicated generally to anyone who is trying to make the world a better place to live in.

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To All of my friends, each one of them made his/her print in my personality to, in my career, and in whole of my life, which I like and appreciate to have, **THANK YOU ALL.**

Abbreviations, And Nomenclature

ABS	American Bureau of Shipping
API	American Petroleum Institute
BHA	Bottom Hole Assembly
BP	Bingham Fluid Model
CBHP	Constant Bottom Hole Pressure
CCD	Continuous Circulation Device
CCS	Continuous Circulation System
CML	Controlled Mud Level Drilling
CPD	Controlled Pressure Drilling
DAPC	Dynamic Annular Pressure Control
DASS	Drilling Approach Selection Scheme
DGD	Dual Gradient Drilling
ECD	Equivalent Circulating Density
ECDRT	Equivalent Circulating Density Reduction Tool
FMCD	Floating Mud Cap Drilling
HSE	Health, Safety, and Environment
HB	Herschel Bulkely Fluid Model
IADC	International Association of Drilling Contractors
MPD	Managed Pressure Drilling
PMCD	Pressurized Mud Cap Drilling
MCD	Mud Cap Drilling
PL	Power Law Fluid Model
RFC	Return Flow Control
RPM	Round Per Minute
UBD	Under Balance Drilling

G_{10m}	Gel Strength after 10 mins, $lb_f/100ft^2$.
K	Consistency Factor (Herschel Bulkley Fluids), $lb_f.sec^n/100ft^2$.
d_h	Hole or Casing internal Diameter, in.
d_{hyd}	Hydraulic Diameter, in.
d_i	Pipe Internal Diameter, in.
d_p	Pipe Outside Diameter, in.
L	Length, ft.
n	Flow Behaviour Index, dimensionless.
N_{ReG}	Generalized Reynolds Number, dimensionless.
p_{ds}	Drill String Pressure Loss, psi.
p_a	Annular Pressure Loss, psi.
p_{acc}	Pressure Due to Acceleration of Drillstring, psi.
p_{bh}	Bottom Hole Pressure, psi.
p_{cl}	Annular Choke Back Pressure, psi.
p_f	Fracture Pressure, psi.
p_{GS}	Gel Strength Breaking Pressure, psi.

p_h	Mud static Column Pressure, psi.
p_p	Pore Pressure, psi.
p_{ss}	Surge and Swab Pressure, psi.
PV	Plastic Viscosity, cP.
Q	Mud Circulation Rate, gpm.
V	Fluid Velocity, ft/min.
V_a	Fluid Velocity inside the Annulus, ft/min.
V_p	Fluid Velocity inside the Drillpipe, ft/min.
$V_{Clinging}$	Velocity of the fluid due to Clinging to Drillpipe while moving, ft/min.
$V_{Displacement}$	Velocity of the fluid due to Volume displacement due to pipe movement, ft/min.
V_{Pump}	Velocity of the fluid due to fluid pumping, ft/min.
YP	Yield Point, $lb_f/100ft^2$.
ρ_a	Mud Density in the Annulus, ppg.
ρ_p	Mud Density in the Drillpipe, ppg.
τ	Shear Stress, $lb_f/100ft^2$.
τ_w	Shear Stress at the Wall, $lb_f/100ft^2$.
τ_y	Yield Stress, $lb_f/100ft^2$.
γ	Shear Rate, 1/sec.
γ_w	Shear Rate at the wall, 1/sec.
θ	Rotor Viscometer Dial Reading.
θ_3	Rotor Viscometer Dial Reading at 3 RPM.
θ_6	Rotor Viscometer Dial Reading at 6 RPM.
θ_{100}	Rotor Viscometer Dial Reading at 100 RPM.
θ_{200}	Rotor Viscometer Dial Reading at 200 RPM.
θ_{300}	Rotor Viscometer Dial Reading at 300 RPM.
θ_{600}	Rotor Viscometer Dial Reading at 600 RPM.

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Chapter 1: Introduction

This chapter involves an introduction and summary of the conventional drilling technique, and the main challenges that pushed the drilling industry towards the development of unconventional drilling techniques. Providing a quick review about each of the unconventional drilling approaches and the main challenges solved by each of them. By the end of the chapter, a State-Of-Art review about the screening and candidacy selection techniques for decision making process regarding conventional and unconventional drilling mode selection.

Conventional Drilling

Till the moment, The majority of the oil wells are drilled in the conventional rotary drilling techniques. The term "Conventional Drilling" means:

1. **Drilling in overbalance conditions**, where Bottom hole Pressure (P_{bh}) inside the well is always higher than formation fluid pressure (P_P) and lower than fracture pressure (P_f). This Principle has to be fulfilled statically and dynamically.

$$P_P \leq P_{bh} < P_f$$

   In Dynamic Conditions, Bottom hole Pressure, will be the summation of the mud hydrostatic pressure plus the additional dynamic annular friction component (P_a), which exists by the effect of drilling fluid circulation and its friction in the annular space between drill string and borehole walls.

$$(P_{bh})_{Dynamic} = P_h + P_a$$

   In Static Conditions, there will be no annular pressure losses, so the bottom hole pressure will equal to mud hydrostatic pressure.

$$(P_{bh})_{Static} = P_h$$

2. **Drilling by open vessel technique.** That means that the top of the well is exposed to the atmospheric pressure, and the return of the mud is directed by means of a bell nipple.
   As the hydrostatic pressure of the mud has to be higher than formation pressure, the recorded pressure of the casing at the surface has to be Zero all the time, otherwise it will be considered as well barrier failure (i.e., mud hydrostatic pressure is lower than formation pressure) and will imply starting well control procedures (e.g., Drillers method, Weight and Wait Method….etc.).

3. **The Stop – Start Circulation technique;** That while making/Breaking the connections of the drill string while tripping in/out, the circulation of mud stops. That will cause losing the mud circulation and all dynamic pressure losses in the well at the connection time.

   A typical representation of the pressure profiles in conventional conditions is shown in **figure.1**.

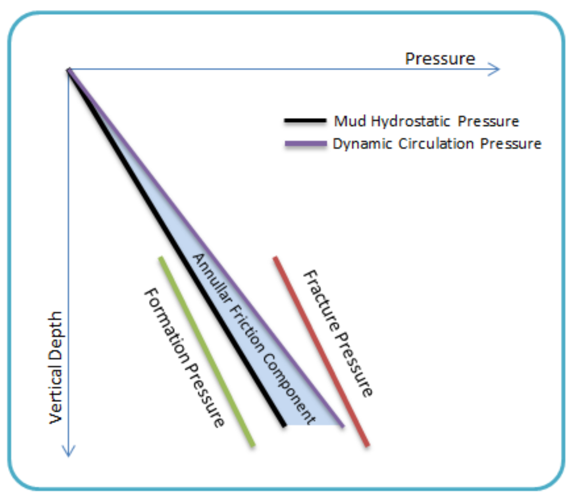


FIGURE 1: CONVENTIONAL DRILLING PRESSURE PROFILES

Challenges vs. Conventional Techniques

The hydrocarbon and energy industry is always in quest for new resources discovery, these new resources are often escorted with new challenges.
Some of these Challenges:

- Narrow Window between the formation pressure and fracture pressure.
- High Pressure / High Temperature Conditions.
- Deep Water Wells challenging pressure profiles.
- Extended Reach Wells, Which are accompanied with hole stability problems.
- The problem of borehole Ballooning/Breathing, which in some cases can cause complete loss of the well because of miss interpretation.
- Wellbore stability. When the borehole is highly unstable, and will require a higher control on the Equivalent Circulation Density ECD spikes at different well operations.
- Highly Uncertain Pore Pressure (P_P)/Fracture Pressure(F_P) Predictions, So the probability of encountering overpressure or losses zones is high.

In normal conventional drilling techniques there is no control over the bottom hole pressure but by the mud rheology, and during normal operations there are some pressure spikes, that will affect ECD.
These ECD spikes and variation can happen due to :

- Surge and swab pressures while tripping in/out.
- The Stop – Start Circulation technique. Which oscillates the bottom hole pressure between the static and dynamic values, while making a connection.
- Acceleration/Deceleration of drill string inside the wellbore.
- Gel Strength Breaking
- Yield Point breaking

By considering the limited control over the bottom hole pressure in conventional drilling techniques, facing challenges like the ones mentioned earlier; will be compromising HSE principles, loss of assets, and failure of operation to reach the target.

Facing these new challenges caused the revolution in the drilling industry and the mindset moving to the unconventional drilling techniques.

Unconventional Techniques

The main unconventional well drilling techniques, classified based on the relationship of different pressures inside the well pore among each other are:

- **Underbalance Drilling (UBD)**

  It is an approach of drilling where the bottom hole pressure is lower than formation pressure, allowing a controlled influx inside the wellbore.

  The International Association of Drilling Contractors (IADC) had defined it “A drilling activity employing appropriate equipment and controls where the pressure exerted in the wellbore is intentionally less than the pore pressure in any part of the exposed formations with the intention of bringing formation fluids to the surface.”

- **Managed Pressure Drilling (MPD)**
  It is an approach of drilling where the pressure downhole is controlled over a narrow pressure window, and not allowing the ECD spikes that happen by conventional drilling ways.
  It is a drilling in over or near balance conditions; no or minimal instantaneous controllable influx will be allowed inside the well bore.

  The main difference between Underbalance drilling and managed pressure drilling is that, UBD accepts to have formation fluid influx while drilling, but MPD is not allowing continuous formation fluid influx inside wellbore.

  IADC defines MPD as "an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. MPD is intended to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process."

A simple and typical representation about the pressure windows and pressure profiles for conventional and unconventional drilling approaches is shown in **figure.2**

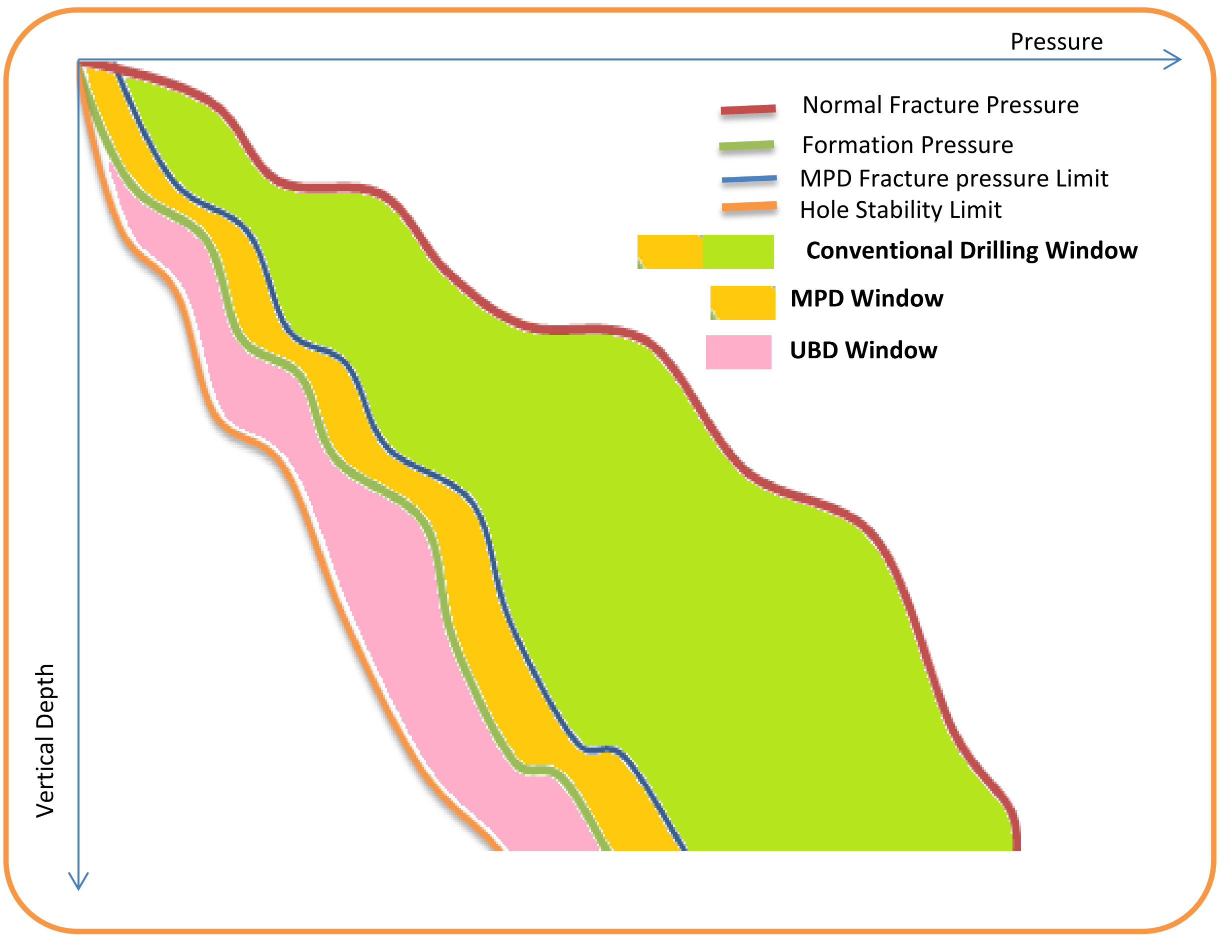


FIGURE 2: DRILLING APPROACHES PRESSURE WINDOWS

Classification and definition of different of MPD techniques

In simple words, MPD is a process aiming to provide additional control over downhole pressure and annular pressure profile during drilling process.

IADC classification of MPD systems can be shown in the following **figure.3**

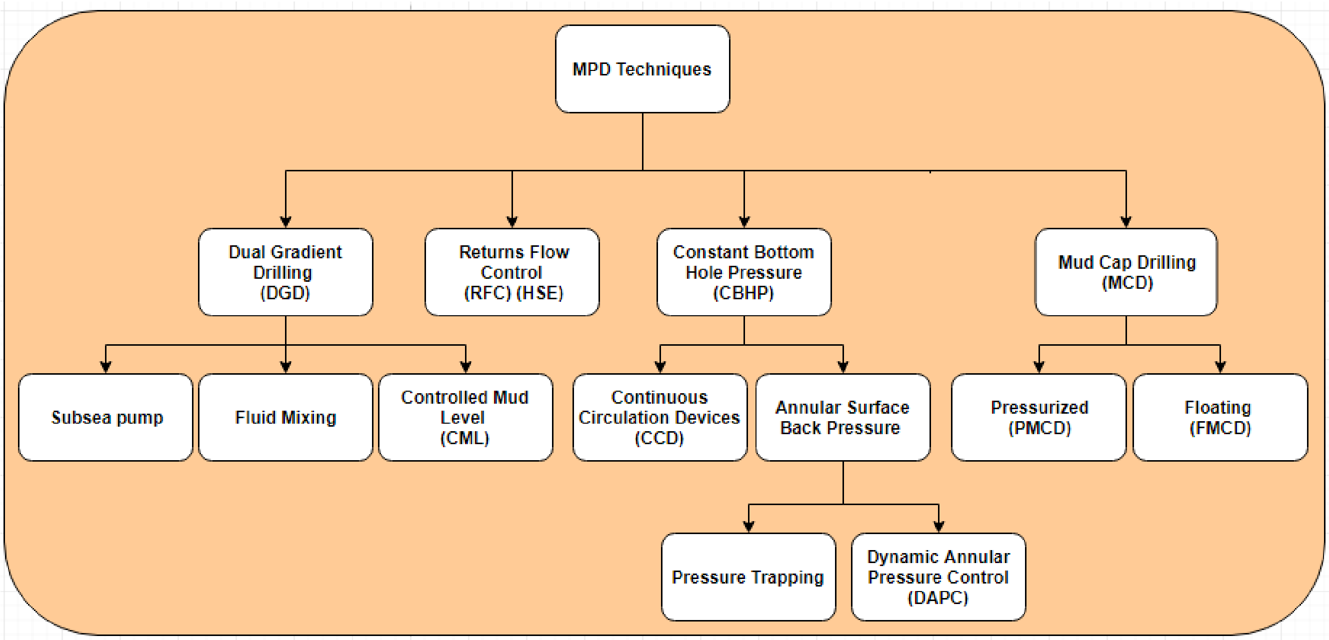


FIGURE 3: CLASSIFICATION OF MPD TECHNIQUES

Dual Gradient Drilling (DGD)

IADC Definition of DGD :

"Two or more pressure gradients within selected well sections to manage the well pressure profile"

DGD is one of MPD methodologies that utilizes two pressure gradients along the wellbore, rather than using one gradient from the well head to the well bottom hole. That dual gradient along the well, aims to manipulate the pressure profile inside the annulus.

This method is utilized and needed mainly in offshore wells due to the reduced fracture gradient profile of the formations below the seabed. That reduction in the fracture gradient is resulted from the reduction of the overburden gradient above the seabed; its ~ 0.5 psi/ft rather than ~1 psi/ft in case of conventional onshore overburden gradient. As a rule of thumb DGD would be required when drilling wells at water depths higher than 5000 ft.

Figure.4 illustrates how the formation, and fracture pressure profiles change from onshore to offshore wells, and how the pressure window becomes tighter as we move to more water depths.

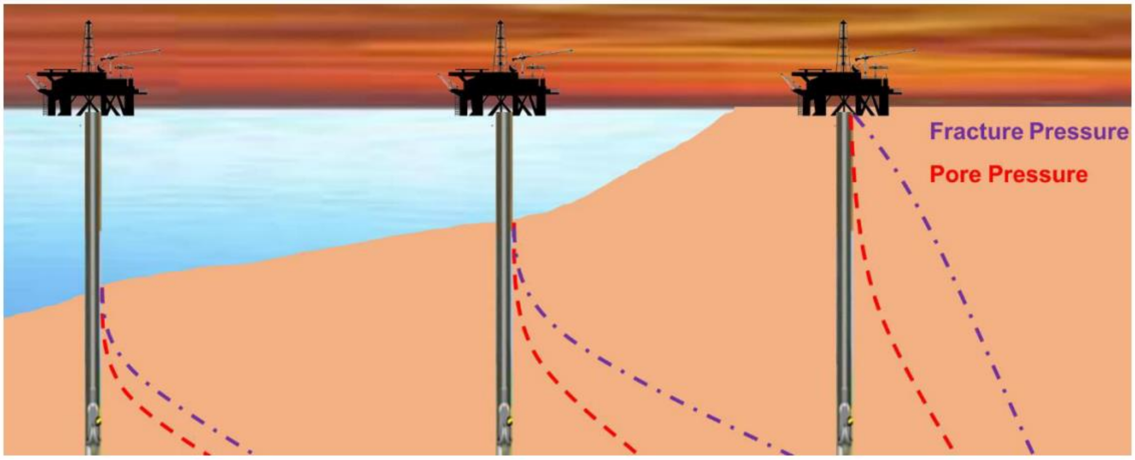


FIGURE 4 PRESSURE PROFILE IN ONSHORE AND OFFSHORE WELLS, (PEREIRA F. F., 2016).

This DGD manipulation of the pressure profile would impact the casing design. Thus, it will reduce the number of casing strings needed in the well before reaching the target depth. This reduction will lead to a reduction in the total well cost and simpler well design.
As shown from **figure.5** in case of riserless-DGD (Curve E + Curve D), the pressure gradient of the deployed mud would allow us to drill a longer vertical section of the well before having the need to add another casing string.

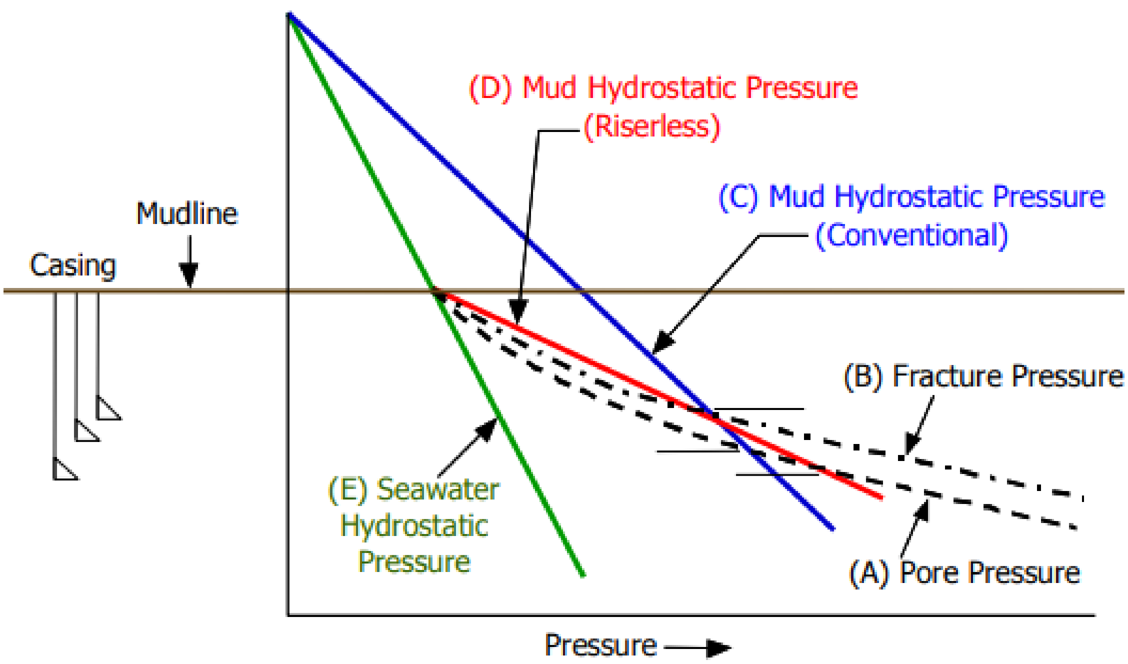


FIGURE 5: IMPACT OF DGD IN CASING DESIGN, (COHEN J.H. AND DESKINS G., 2006).

The application of the dual gradient profile can be done by one of the following variations:

- **Subsea pumping (Dual Gradient MudLift)**
  Often can be defined as the real DGD as it acts as if the drilling rig is on the sea floor.

  The well will have two fluid gradients one from the bottom hole till the seabed and the other from the seabed till the surface inside the riser, and the two fluids are separated by a subsea rotary device (SRD). The fluid in the riser is usually a light weight fluid that is close to the sea water density.

  A positive displacement pump is placed on the seabed above the BOP and below the SRD that have the mission of withdrawing the mud from the annulus and pumping it back to the surface through a line attached to the riser.
  One of the variables, that the drilling process could be riserless and the fluid column above the SRD is just the sea water directly as shown in **figure.6**.

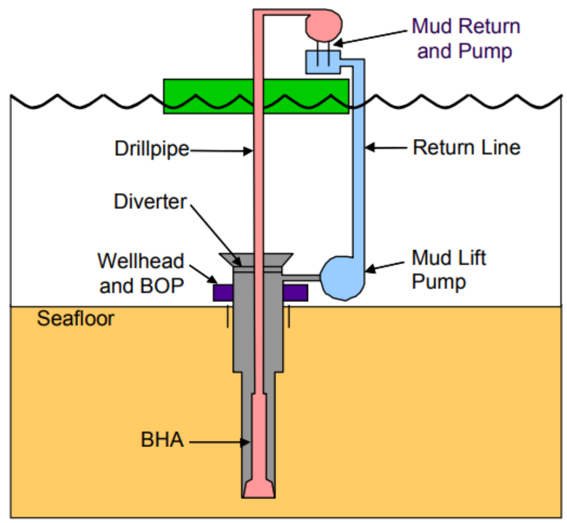


FIGURE 6: DGD - PUMP LIFT SYSTEM, (COHEN J.H. AND DESKINS G., 2006)

- **Fluid Mixing**
  This is done by injecting a low density fluid or material, in the riser in order to reduce the return mud weight inside the riser, which will lead to a dual gradient profile inside the well.
  The mixing can be with:
  - Gas
  - Lower Density Liquid
  - Light Weight Solid Additives LWSA (e.g., Hollow spheres)

  The injection can be from a single point at the bottom of the riser, or multiple injection points can be used. An illustration of the sphere injection DGD process is shown in **figure.7**.

  Moreover, this method can be used in onshore applications, by adding a parasite mixing fluid injection tube in the surface or intermediate casing.

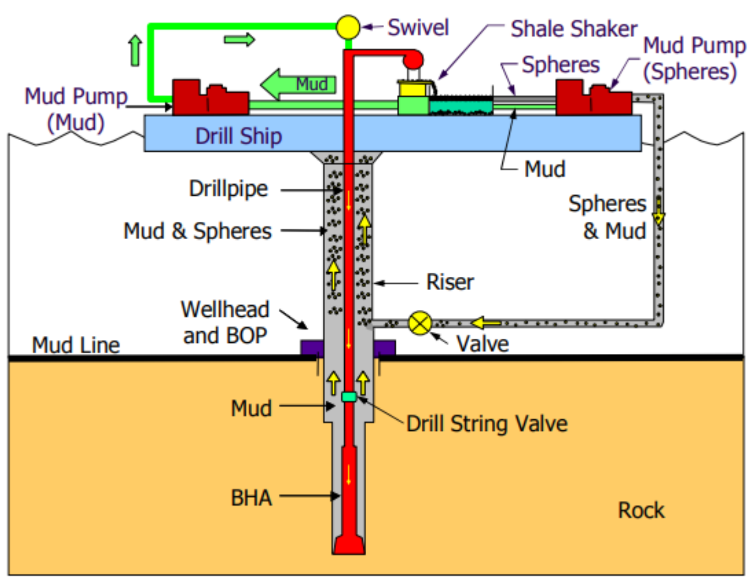


FIGURE 7: DGD - HOLLOW SPEPHERE SYSTEM (COHEN J.H. AND DESKINS G., 2006).

- **Controlled Mub level (Mid Riser DGD)**
  In this method two fluids with different densities are utilized to control the pressure profile inside the well. The lower density fluid can be gas. Unlike the Mud lift DGD, The two fluids are in contact as there is no SRD is used to separate the two fluids.
  The control of the bottom hole pressure and profile is done by controlling the heavy mud level in the riser by means of a pump installed at different levels on the riser (**figure.8**). Increasing the return mud pumping rate will reduce the heavy mud level in the riser and vice versa.

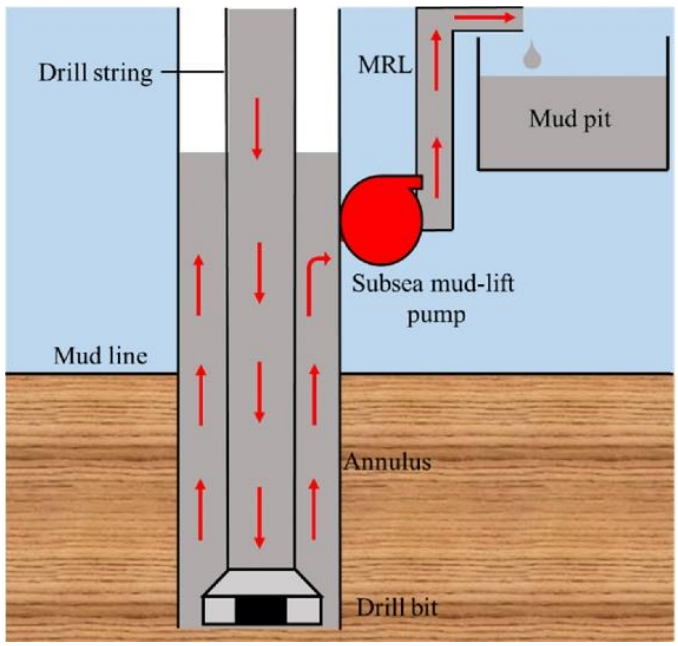


FIGURE 8: DGD - CONTROLLED MUD LEVEL (COHEN J.H. AND DESKINS G., 2006).

Mud Cap Drilling (MCD):

MCD is drilling with no mud returns from the well to the surface. This methodology is pretty beneficial when drilling highly fractured zones. thus when drilled with conventional ways, the well will have severe or total losses problems. This method requires an abundance of a sacrificial drilling fluid to be able to be pumped all the time in the wellbore. Moreover, the drilled losses zones has to have the ability to accept the mud and cuttings to be injected into it.

This system can be applied in land and marine operations. It is potentially preferred in offshore conditions due to the abundant amount of water that can be utilized in the drilling process.

Mud Cap Drilling can be one of two variations (figure.9):

- **Floating Mud Cap Drilling (FMCD)**
  As defined by ABS (American Bureau of Shipping):
  "A drilling process that involves maintaining a mud level in the annulus below the surface for hole stability and well control purposes, and no surface back-pressure. In MCD, there are no flow returns to the surface while maintaining mud column on the annular side."
  It's a mud cap drilling where the drilling fluid column pressure is equal to the formation pressure, and the fluid level is kept lower than the surface level. Keeping the mud level constant will keep the bottom hole pressure constant. Fluids may be pumped from the surface in the annulus in order to keep the mud level constant, or to mitigate any potential influx in the well.
- **Pressurized Mud Cap Drilling (PMCD)**
  It's a mud cap drilling where the hydrostatic mud weight is lower than formation pressure.
  The main variation between FMCD and PMCD, is that in PMCD the drilling fluid reaches the surface, but not allowed to be circulated out of the well by mean of a Rotary Control Device RCD. Having annular pressure all the time while drilling will provide the communication with the formation pressure and the detection of any influx as fast as possible. Also, as mentioned in FMCD, fluids can be pumped from the annulus in order to bull-head any influx which had entered the wellbore.

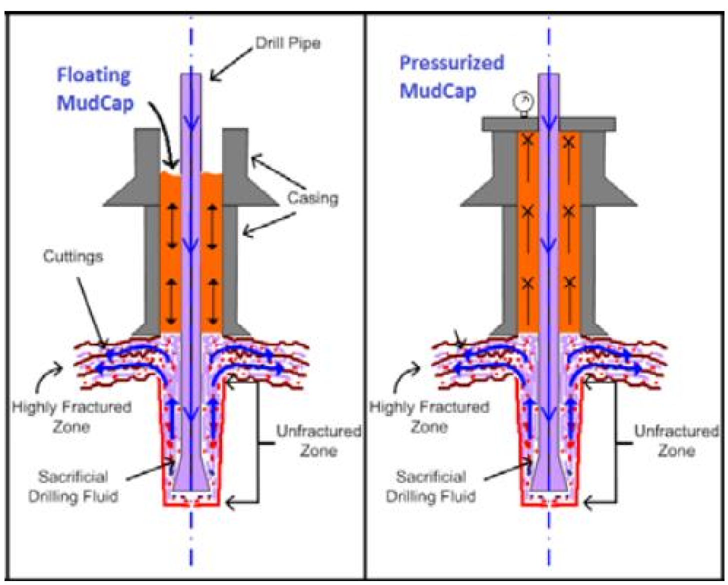


FIGURE 9: MCD VARIATIONS, (GOODWIN B., NADURI S., AND MEDLEY G., 2014).

Return Flow Control (RFC) (HSE):

Health, Safety, and Environment (HSE) method involves using closed loop circulation system. Closed loop circulation system using RCD and diverting the mud return flow under the rig floor. And the mud flow line out of the well to be equipped with a Remote controlled choke in order to help to control any kick or well control situation in the well as fast as possible.

This method is mainly useful in drilling in high H_2S concentration zones. That at any accidental influx from the formation the containment will be faster and easier, and the probability of any leak will be lower.

Constant Bottom hole pressure CBHP:

In conventional drilling technique and by using **Stop/Start Circulation at** each connection made, the mud circulation in stopped and bottom hole pressure drops rapidly, generally overshooting the static balance by several hundred psi, before rising to the static level. This **negative pressure surge** may induce flow from the formation if it falls below the pore pressure.
After a connection in made, circulation is re-started and bottom hole pressure rises rapidly, generally overshooting by several hundred psi, before decreasing to the circulation level. This **positive pressure surge** may exceed the fracture pressure anywhere in the exposed wellbore.

That Circulation stop/start technique in extended reach wells or HPHT wells where the window between the formation and fracture pressure is small, might induce a lot of undesired kick and loss situations while drilling the well.

Several statistical studies had been made to discover the major reason behind kick incidents in drilling process.

One statistical study of deep water floating rigs kick data (Barkel J.D., 2015) show that :

- 25% of kicks happen during drilling and circulating.
- 25% of the time kicks are related to making connections.
- 50% of the time kicks are related to tripping the DP out of the well.

Another study by (Fraser D., 2014),

- 15% of the Kicks happen during Tripping out.
- 70% of the Kicks happen during making a connection.

By reviewing at these data, it can be found that most of the kicks happen either due to losing the dynamic circulation pressure during connections, or during tripping out due to swabbing effect. Both of them account for more than 75% of kick incidents.

That was the reason for developing constant bottom hole pressure (CBHP) MPD that keep the Bottom Hole Pressure (BHP) constant and to prevent the bottom hole from pressure fluctuations that happen mainly during making the connections.

CBHP MPD approach will keep the pressure downhole constant by one of the following methodologies:

1. **Using Continuous circulation devices (CCD).**
   By utilizing these continuous circulation devices, the circulation will be maintained in the well, while making the connection. That will keep the downhole pressure in steady state at the same value of dynamic ECD, while making the connection without any positive or negative surges.
   Figure.11 show the pressure profile when utilizing CCD in the drilled sections

2. **Using closed loop circulation system, and Annular back pressure application**
   While the circulation is stooped while making a connection the annular pressure losses effect in the downhole pressure is eliminated. This system is used mainly to apply back pressure from the surface in the annular side ($\boldsymbol{P_{Cl}}$) of the well while making a connection. The value of the back pressure that has to be applied can be calculated from any hydraulic simulator software.

   That when the well is Dynamic:
   The Downhole pressure $= \boldsymbol{P_h + P_a}$

   While Making the Connection or/and losing the circulation out of the well:

   The Bottom Hole pressure $= \boldsymbol{P_h + P_{Cl}}$

The pressure profile inside the well, while utilizing Surface back pressure MPD system, is shown in **figure.11** compared to the Continuous Circulation method in **figure.10**.

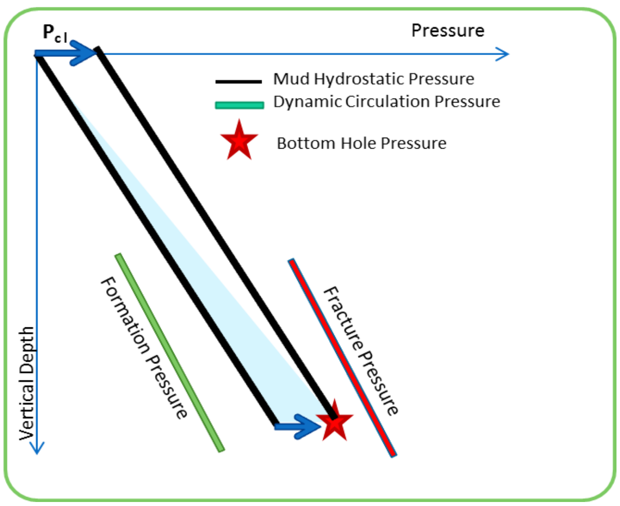


FIGURE 11: THE BOTTOM HOLE PRESSURE IS HELD CONSTANT BY APPLYING ANNULAR SURFACE BACK PRESSURE WHILE MAKING CONNECTION

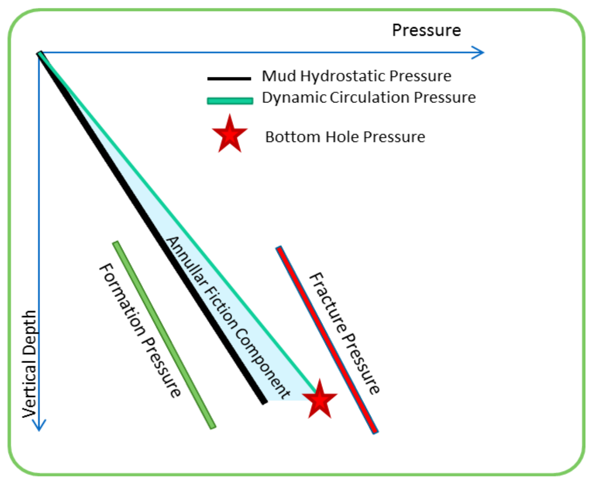


FIGURE 10: THE BOTTOM HOLE PRESSURE IS HELD CONSTANT BY KEEPING THE CIRCULATION WHILE MAKING CONNECTION

Both of these systems applications doesn't contradict each other. In the contrary, the application of both of them will combine the benefits of both of them to drill the well in the best conditions. That will be explained in details in the next chapter.

This is the typical and conventional definition of MPD system. Thus, in oil industry when mentioning MPD in any article, annular back pressure application in a closed loop circulation system will be the one which is considered.

Equivalent Circulation Density Reduction Tool (ECD RT):

In deep water and extended reach wells the annular pressure losses becomes huge increasing the ECD significantly. High ECD causes a lot of hole instability and mud losses problems.

The conventional ways of reducing ECD:

- Mud rheology thinning.
- Lowering annular losses by making bigger clearance between BHA and bore walls.
- Using liners instead of casings
- Reduction of drilling fluid circulation rates.
- Reduction of rate of penetration. That will lead to the reduction of cuttings load in the mud.

There had been a search for more methods that would reduce or eliminate the effect of annular friction losses inside the well bore. ECDRT had been proven by field tests to achieve that target, by installing a turbine pump in the drill string that works to counteract the effect of annular friction losses by reducing the total mud hydrostatic head.

The ECDRT works to provide energy and push the drilling fluid up in the annulus removing the effect of annular pressure losses from the ECD.

The ECDRT is a self-activated tool, driven by the circulation of drilling fluid. It starts when the fluid is circulated, and it stops when the circulation stops.

ECDRT consists mainly from three main parts, shown in **figure.12**:

1- Turbine Motor, which takes the energy from the circulating fluid and provides mechanical energy.
2- Multistage pump, which is connected to the motor. So that it will rotate when the circulation is on.
3- Annular seal Packers, to ensure and directs the drilling fluid through the turbine, and to provide the seal between the upper and lower sections of the annulus.

Usually this tool is limited to be used in the cased sections. So it will need repositioning as drilling proceeds to more depths
Field tests in 2006 found that the annular pressure can be reduced by up to 450 psi, by using ECDRT.
Field tests had found that Surge and swab effects are significant and magnified when utilizing ECDRT. Thus, The optimization of tripping speeds is mandatory when utilizing ECDRT.

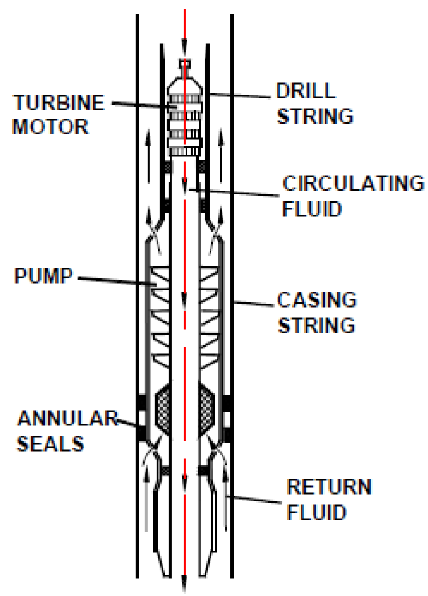


FIGURE 12: ECDRT SCHEMATIC (BANSAL, 2007).

State-Of-Art of MPD Candidate selection Methodologies:

MPD is a great technique that solve a lot of drilling problems and reduce Non Productive Time NPT while drilling. But also, MPD technique is adding more complexity and experience requirements in the drilling site. More complexity means more vulnerability to risks.

Thus, before deciding to use MPD in any well, a screening criteria and feasibility study to be made in order to decide if the well conditions require MPD or not, or even if MPD will affect the well economics in a positive way or not. Maybe some times a change in the hydraulic parameters, or the approaches will be enough to solve the problem and proceed to drill the well in a conventional way.

Several attempts had been already made to develop a systematic approach for the evaluation of well conditions and problems, and the assessment of MPD options to overcome these drilling problems.

All of these models and methods aim to provide a decision making tool for the operators and engineers concerning MPD deployment.

This section will provide an overview of the published models and attempts.

MANAGED PRESSURE DRILLING CANDIDATE SELECTION Model CSM

Nauduri (2009) provided a Candidate Selection Model CSM, As a part of a research developed at TAMU, which is intended as a preliminary screening tool and mechanism for MPD applications.
The research study provided an explanation of a workflow, and basic steps for the MPD screening process. Aided with a special hydraulic simulator DZxION, which is developed to take MPD and drilling variables into consideration.

The proposed steps for Candidate screening process:

- **Defining, identifying, and establishing the purpose.**
  The definition of project resources constrains of time, money, expertise, HSE regulations, MPD availability,…etc.

- **Procuring information.**
  To collect the data of the considered well case. The basic data which are required to be able to assess and run full hydraulic analysis in the following step.
  That basic data includes:
    a. Pressure Profiles
    b. Wellbore Geometry
    c. Drill String Assembly and Geometry
    d. Mud Rheological properties
    e. Drilling Problems to be faced, and needs to be solved.

  In all of these data, especially with faced drilling problems, offset well data can be of a great importance to be collected and evaluated.

- **Performing a hydraulic analysis.**
  To run the hydraulic calculations and to know the changes in downhole pressure and ECD in different well operations of Drilling tripping and making a connection.
  Also, the hydraulic Analysis can be used to run a sensitivity analysis on different available options of the drilling variables (i.e., Mud rheology, BHA design, well geometry…..etc.).

- **Selecting the method.**
  Based on the known system limits and hydraulic analysis, the need (or not) for MPD system will be known. As it's a preliminary decision and screening tool, all MPD systems are to be considered in the study, that advantages and disadvantages of each of them to be defined.

And three additional steps, those will increase the level of confidence in the taken decision regarding the MPD method to be utilized:

- Determining the viability of MPD using a preliminary economic case.
- Recommending equipment.
- Performing a hazard and operability analysis and hazard identification.

The basic idea of the proposed candidate selection model CSM is to start by running the hydraulic calculations with a developed software called DZxION, with the purpose to find out if the well can be drilled conventionally without any problems. this condition will be met when the static and dynamic mud circulating pressure profiles lies in the mud window (i.e., between formation pressure and fracture pressure for the drilled section). If this conventional drilling basic assumptions are not met, then the software can be used to study the applicability of different MPD techniques, and its associated variables.

As mentioned by the author, some of the associated variable for MPD techniques that can be studied (Moreover, can be used as constrains) by the hydraulic simulator are the ranges of: Mud Weights, mud circulation rates, and required surface backpressures. All of the previous parameters to be studied both statically and dynamically.

That proposed CSM will give one of three main results:

- **MPD is not required:** The well can be drilled conventionally.
- **MPD is applicable:** the well cannot be drilled conventionally, and MPD can be used to drill the well with the provided constrains and range of variables.
- **MPD is not useful:** the well cannot be drilled conventionally, and MPD is surpassing the provided constrains and variables. So, MPD won't be an optimum solution.

That workflow is explained within the following flow Diagram shown in **figure.13.**

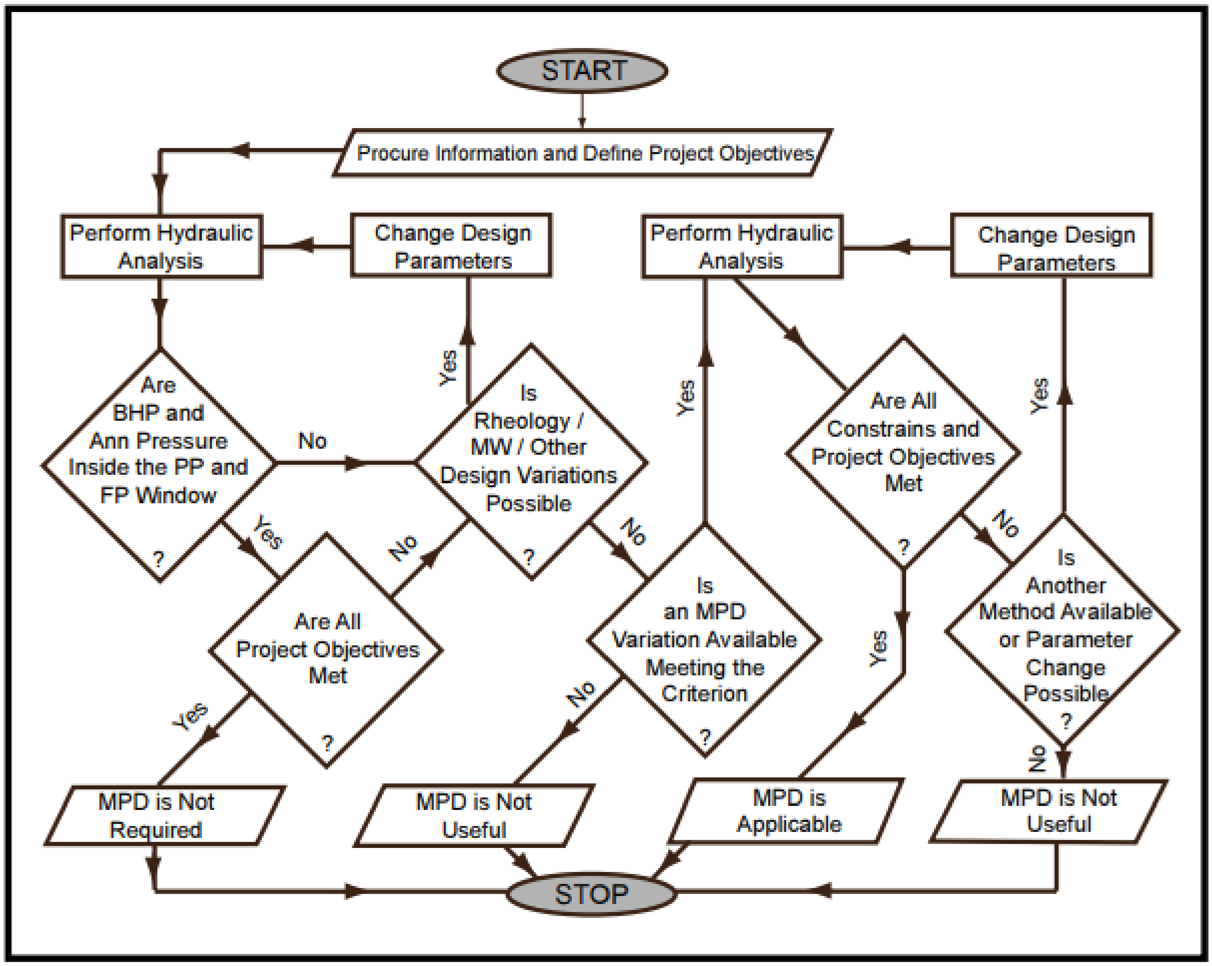


FIGURE 13: MPD - CANDIDATE SELECTION MODEL CSM, (NAUDURI, 2009).

Controlled Pressure Drilling (CPD) Candidate Screening Methodology

Villatoro et al. (2009) as a part of a project with Weatherford, Provided an explanation of the development of the initial SURE screening process. This screening methodology had taken a bigger scope of screening involving Underbalance and Air Drilling Approaches in the screening process. All of these technologies included under the name of Controlled Pressure Drilling CPD.

CPD is the drilling process that enables a precise control of the pressures inside the wellbore by the use of engineering equipment and processes. That definition is more or less mocking the definition of MPD. But The Authors consideration of CPD is taking into account mostly all methods of controlling the BHP by having a closed loop, pressurized circulating system. Providing a more general screening tool for controlled pressure drilling CPD techniques. CPD Techniques which had been mainly considered in this screening process are: Air drilling (AD), Managed pressure drilling (MPD), and Underbalanced drilling (UBD).

The three CPD techniques are:

- **Air drilling (AD):** is a cost driven drilling approach. To improve drilling economics by increasing rate of penetration (ROP) and extending bit life. Allows influx to enter the wellbore during drilling.

$$P_p > P_{bh} = P_h + P_a + P_{sc}$$

- **Managed pressure drilling (MPD):** is a drillability driven technique. To optimize drilling process by decreasing NPT and mitigating drilling hazards. Does not allow influx to enter the wellbore during drilling.

$$P_p \cong< P_{bh} = P_h + P_a + P_{sc}$$

- **Underbalanced drilling (UBD):** is a productivity and formation damage reduction driven technique. To increase reservoir productivity and maximize NPV by reducing formation damage and enhancing reservoir characterization. Allows influx to enter the wellbore during drilling.

$$P_p > P_{bh} = P_h + P_a + P_{sc}$$

Important to mention that all included systems in that screening criteria are closed loop circulation system. The MPD systems that had been mentioned in the study are only MPD CBHP with surface back pressure application, and PMCD.

The screening methodology is based on two steps process:

First Step: An Internet based low resolution screening tool that gives a guidance and a rating of how beneficial will be CPD.

Second step: perform an advanced high resolution analysis that contains the exact quantification of how the CPD technique will benefit the drilling process.

The following Graph in **figure.14** explains the screening criteria for the three CPD techniques and SURE screening process.

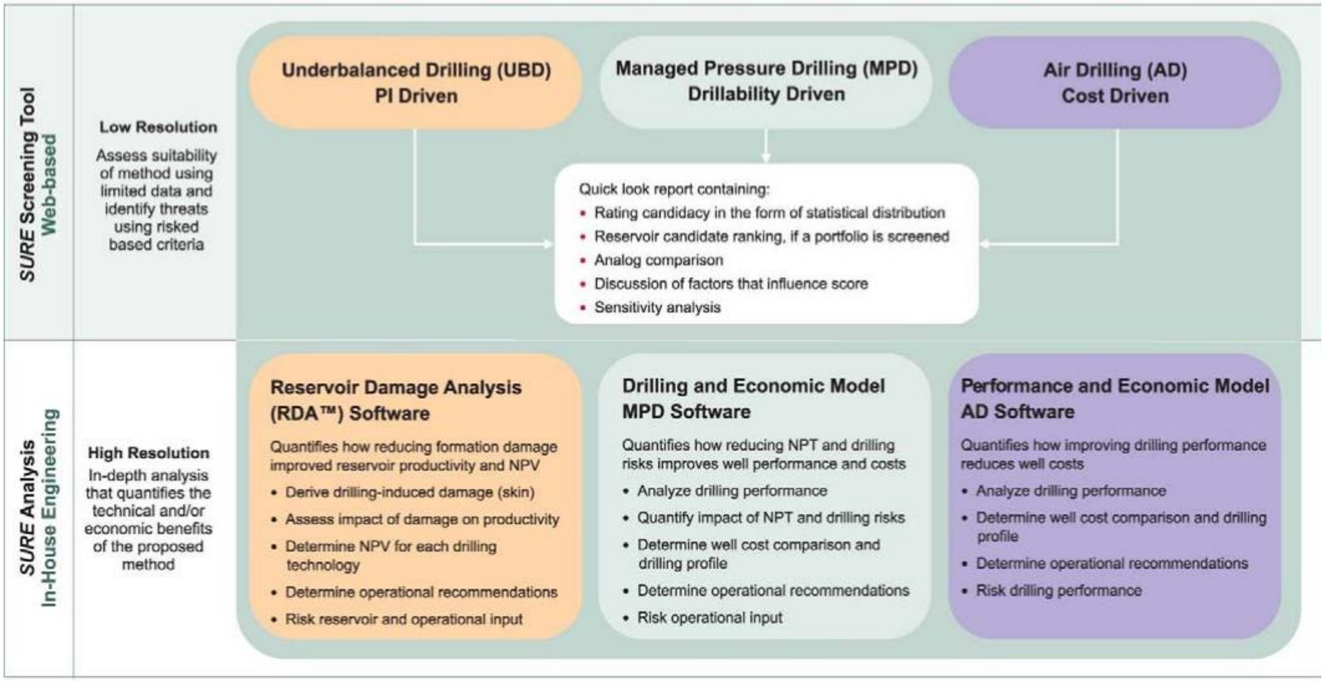


FIGURE 14: CPD SCREENING PROCESS, (VILLATORO ET AL., 2009).

The CPD online screening tool is a low resolution screening tool. That works with limited amount of data to provide a quick fuzzy logic based evaluation about the candidacy for any of the three CPD options.

The screening is done based on the following Points:

- Hole section: top, intermediate, or reservoir.
- Presence of shale and coal.
- Well orientation direction.
- Drilling objectives: NPT, formation damage.
- Directional drilling requirements.
- Source of NPT.
- Hole size.
- Presence of drilling hazards.

When a CPD technique is chosen for evaluation, the user will be asked to enter a range of technical and economic parameters. These parameters will be used in the screening process.

The parameters needed for the quick evaluation for MPD applications screening includes:

- Well depth.
- Mud details.
- Lost-circulation events.
- Differential sticking events.
- Lost-in-hole events.
- Wellbore ballooning and/or fracture charging.
- Well-control events.
- Conventional costs and duration.

The screening criteria for candidate selection will be based on a score calculated by three modules

- Time.
- Improvement of HSE conditions (e.g., H2S).
- Intermediate casing score.

The primary step in the score determination is the evaluation of the **time saving score** by utilizing MPD technique versus conventional drilling. That score will be calculated from the following relation

$$\Delta T = \frac{\Delta T_{Hazards} + \Delta T_{ROP} - \Delta T_{MPD}}{T_{Conventional} + \Delta T_{Hazards}} * 100\%$$

- ΔT , Is the time score for MPD system application
- $\Delta T_{Hazards}$, Time delays caused by drilling hazards, occurring when using conventional techniques.
- ΔT_{ROP}, ROP time savings, when utilizing MPD system and reduce mud weight.
- ΔT_{MPD}, Additional time needed when using MPD techniques.
- $T_{Conventional}$, Time needed for conventional drilling without problems.

The time savings ΔT is then evaluated,

- ΔT is Positive, Indicating that MPD system is beneficial and time saving.
- ΔT is Negative, Indicating that MPD system is not beneficial, and conventional drilling is more time saving.

In addition to the time saving score, comes the **H2S score**. If H2S is present in the formations to be drilled, then MPD closed loop system will become more favorable than conventional drilling.

The third score will be related to **intermediate casing strings score**, MPD is expected to lower the number of casing strings to run in hole. This to be evaluated by intermediate casing score.

Adding all of the three scores Time, H2s, and intermediate casing score, will give an overall quick evaluation about the candidacy and benefits of applying MPD system in drilling the well.

The output to be a score number between -100 to 100:

- -100, MPD option is not a recommended option.
- 0, No realized advantages of Using MPD system.
- 100 MPD option is fully recommended.

IADC MPD Tool 2012:

A simple free software provided by IADC in order to aid qualitatively the screening process of MPD Candidates.

The assessment process is one following these steps:

1- Data Input

Definition of the general data about the well

   a. Offshore or Onshore
   b. If Offshore, water depth
   c. Drilling fluid
   d. Predicted pressure regime uncertainties
   e. Equipment used in drilling process

2- Definition of the goal and objectives

In this part, the user is expected to define the expected challenges or problems that are to be faced within the well design and drilling process.

Example of the challenges and goals to be met:

   a. Lost Circulation
   b. Abnormally pressurized zone
   c. Drilling in HPHT areas
   d. Drilling though narrow pressure windows
   e. ECD effects
   f. Surge and swab Mitigation
   g. Increase of ROP

3- Based on the provided data and the needed objectives, the software will give a preliminary assessment of all MPD.

The assessment and recommendation is based on a rating criteria made in an Excel sheet attached to the software. That excel sheet have a rating and assessment of each MPD technology in solving each of the provide problems.

That rating will be one of five numbers (-1), (0), (3), (5), or (10).

The rating as provided from IADC for each system versus each objective can be reviewed in appendix B

The legend as provided from the software:

   a. (-1) The system cannot be applied, or it will have adverse effect with respect to the needed goal.
   b. (0) The system is not useful in solving the considered issues.
   c. (3) The system can be used to provide a partial benefit in reaching the target.
   d. (5) The System can be used as a primary system to solve the problem, and to meet the objectives.
   e. (10) The System can be used as a primary system to solve the problem, and to meet the objectives, and the system is highly recommended in to solve that issue.

Example of the IADC Tool Application:

The inputs to be:

Onshore well – Single phase oil base mud – Pressure Profile uncertainty

The List of Goals/objectives:

1- Drilling Through a narrow pressure window.
2- Mitigate Surge and swab problems.

The output:

Following **figure.15** shows that the recommended solutions starting from the most recommended to the least recommended are:

1- Continuous Circulation Devices.
2- CBHP/ Back Pressure Application of Trapped Pressure.
3- DGD.
4- MCD.
5- UBD.

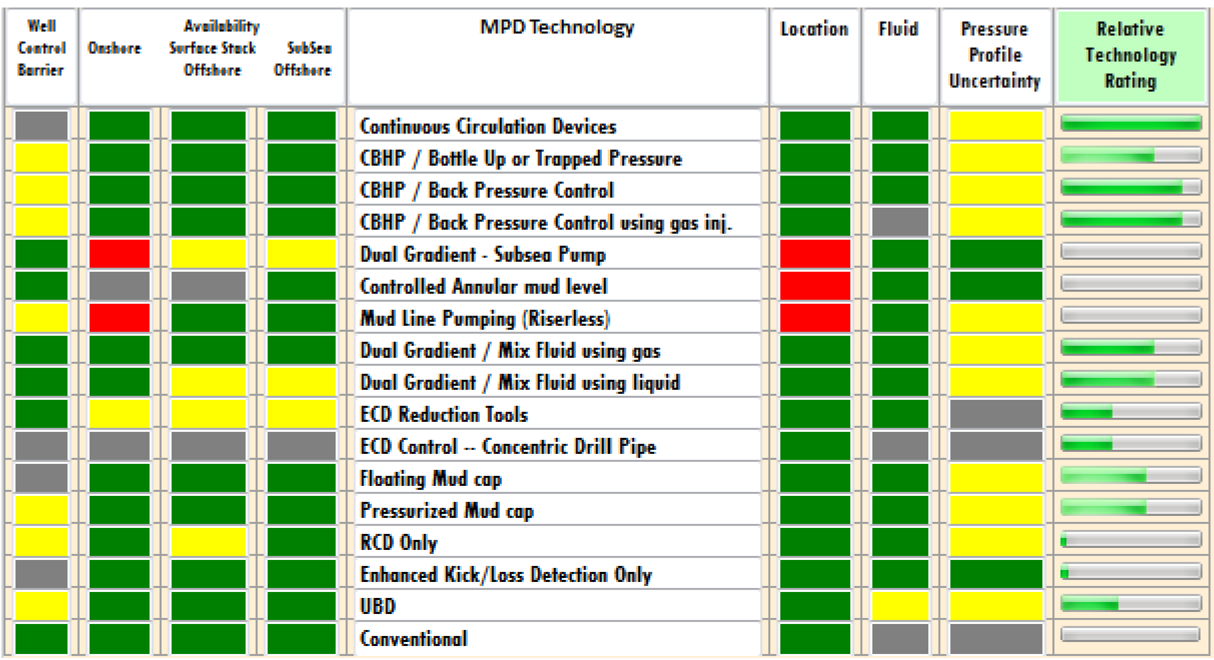


FIGURE 15: SCREENSHOT OF IADC MPD TOOL EXAMPLE

To meet the needed objectives of narrow pressure window and surge and swab problems, it makes sense that the general need to be one of CBHP MPD systems.

The color code in the pressure profile uncertainty column:

- Green : this technology is potentially used for drilling that well section in these conditions.
- Yellow: Usually this technology is not used for drilling that well section in these conditions.

We find that in all CBHP MPD techniques and continuous circulation devices are with yellow color. That is because usually these MPD technologies usually require a high level of confidence on the provided/predicted pressure profiles.

Moreover, we find that the Enhanced Kick/loss detection system is marked to be green, within that high uncertainty of pressure profile. But it works as an assisting system to the main MPD approach to be used, not as a standalone system.

In the provided case, the software give the Continuous Circulation devices the highest rating among other technologies to meet the needed objectives. Adding the Enhanced Kick/loss detection system as an assisting system will be partially beneficial to meet the objectives.

Chapter 2: Constant Bottom Hole Pressure CBHP – MPD in details

Having a constant pressure down hole and not allowing excessive pressure fluctuations is one of the most important aspects for hole stability and reduction of a wide range of drilling problems. A big part of the NPT during conventional drilling process can be saved by just having the pressure steady on the bottom hole.

This chapter will provide in depth review about different CBHP MPD methods and how they are helpful in solving many of drilling issues. Moreover, making a comparison between the two main major methods, applying surface back pressure and using continuous circulation systems. With a quick review on the equipment utilized on these MPD processes.

Usually when MPD is mentioned, the first idea that jumps in the listeners' minds that it is a closed loop circulation system with surface choke to apply back pressure. But in that study, Open loop Continuous Circulation system CCS CBHP MPD will be dealt with, as a standalone system that can be utilized to control bottom hole pressure fluctuations without the need to surface back pressure.

By the end of this chapter, there is a review about some of the case studies that proved that utilizing CBHP MPD systems are beneficial and already utilized in solving many of drilling problems.

General CBHP MPD Systems Description and Equipment

Continuous Circulation Devices (CCD)

CCD are devices which are used to keep the downhole pressure regime in a steady state profile and constant by keeping the circulation in the well without interruption during any connection making/ breaking.

A common form of continuous circulation devices uses a manifold connected into the rig's standpipe that diverts flow to and from the top drive to a side port on a sub threaded into the top of each drilling stand. The sub contains two internal flapper valves that enable flow through the side port, automatically isolating the top drive, and providing circulation downhole while making or breaking a connection.

The History of continuous circulation devices:

- The evolution of CCD started with continuous circulation Coupler devices as a Joint Industry Project JIP – between six major oil companies. The limitation of the Coupler was the long connection time, due to complex flow diversion process with an average connection time of 23 mins.
- Then Eni-Circulation devices are considered to be the start of innovation of Sub based continuous circulation systems. Which overcomes some limitations of the coupler and less complex operation in the rig floor.

  E-cd sub contains two internal flapper valves that enable flow through the side port, automatically isolating the top drive, and providing circulation downhole while making or breaking a connection.

Then many market providers are emerged in the process of innovating CCDs, some them are mentioned below in **figure.16** and **table.1.**

FIGURE 16: TIMELINE OF CCD DEVELOPMENT, (COURTESY OF DRILLMEC S.P.A).

TABLE 1: CCD PROVIDERS, (COURTESY OF DRILLMEC S.P.A).

Year	Company	System
2004	JIP (6 Major Oil Companies)	Coupler
2006	Eni – Halliburton	E-cd
2009	Canrig – Nabros	Non Stop Driller
2012	Weatherford	Continuous Flow System
2015	Drillmec	HoD – Heart Of Drilling
2018	**Eni - Halliburton**	**E-cd Plus**

DRILLMEC S.p.A – Heart of Drilling HOD® – Continuous Circulation System

System operation and description:

There are special subs which are pre-installed in the drill string. These subs has a side valve which can be used for maintaining the circulation while breaking up the drill pipe. There will be a special clamp which is able to attach to the sub and open the side valve allowing the circulation from the side valve. A special manifold to be utilized to control the direction of the mud circulation through the drill string to be from the top drive section or the side valve of the subs.

The general layout of the system is shown in **figure.17**

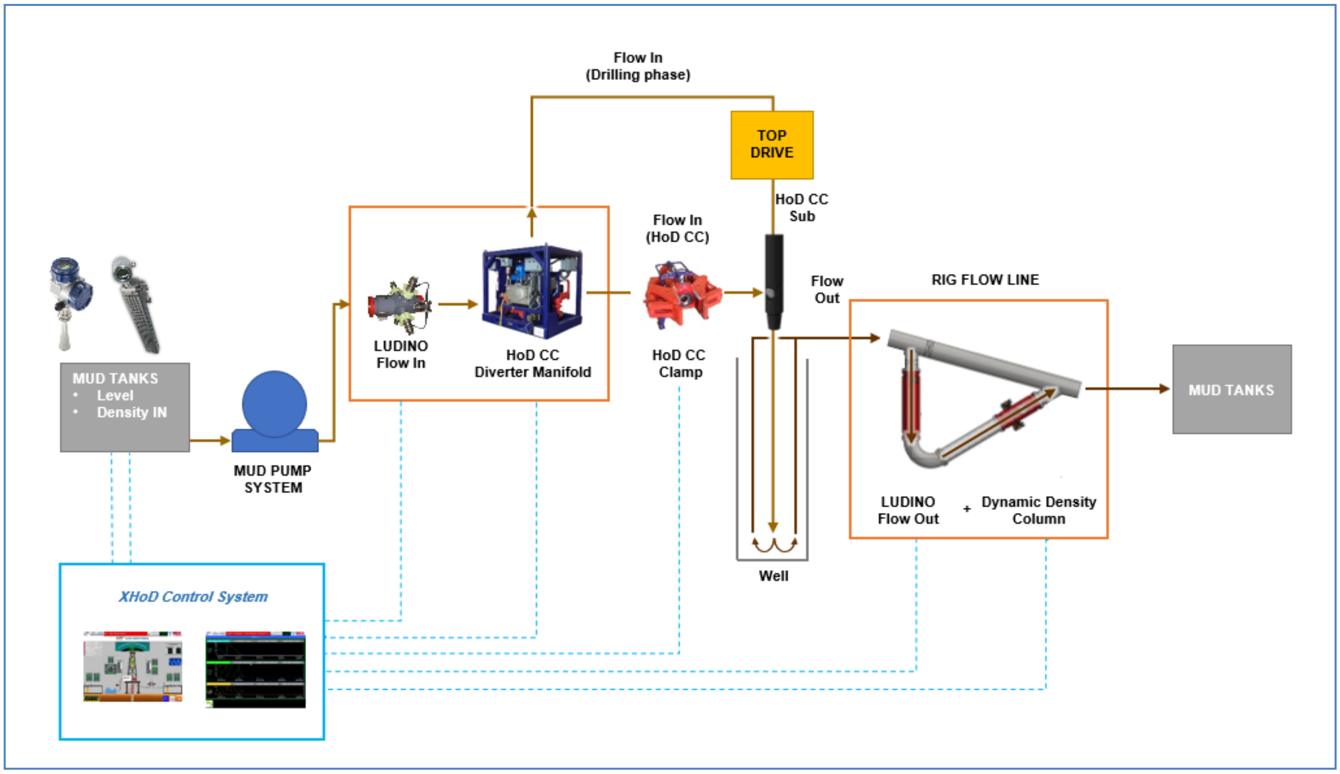


FIGURE 17: HOD CCS GENERAL LAYOUT, (COURTESY OF DRILLMEC S.P.A).

The process of operation to make / break a connection with HoD Continuous Circulation system:

1- The HoD CC clamp is to be attached to the sub and to the side valve, removing the safety plug from it.
2- then the manifold will divert the flow from the top drive direction to the side valve direction. That diversion of flow will open the side valve and close the top flapper valve.
3- By that time the circulation in the well is totally isolated from the top drive direction and the stand on the top of the clamp can be removed/added safely.
4- After finishing the connection, the manifold will divert the flow to the top drive direction again and the side sub valve will be closed
5- The clamp will return the safety plug. Then, detached from the drill string.
6- Afterwards, the drilling/Tripping process continues.

HoD is comprised Mainly of :

1. CCS Subs,

Which utilize two flapper valves (Axial and Radial), show in **Figure.18**. The sub has a dual flapper valve configuration. The upper flapper valve acts as a check valve when disconnecting the top drive while adding a new stand.

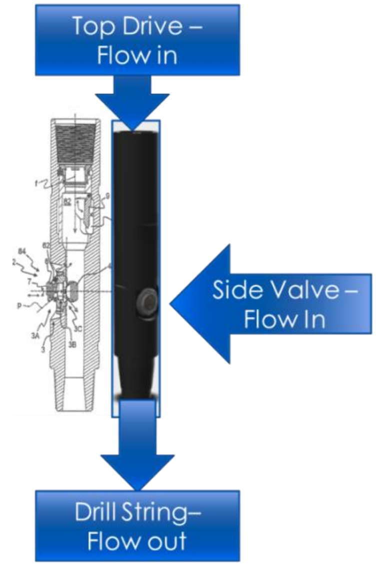


FIGURE 18: HOD® CCS SUB, (COURTESY OF DRILLMEC S.P.A).

2. CCS Clamp,

The HoD Clamp **Figure.19**, provides sub lateral valve opening/closing without manual interaction. The operative sequence is automatically performed by means of a HMI (Human machine Interface) located in a safe area on the rig floor.

3. Manifold,

The manifold shown in **Figure.20**, Controls the process of diversion of the flow direction from to Drive to the side valve and vice versa.

4. Mud Flow Meter MFM System,

Venturi flow monitoring system **Figure.21**, that comprised of sensors and flow monitoring tools. That helps in a sudden detection of any kick or loss incident happens in the well.

FIGURE 19: HOD® CCS CLAMP, (COURTESY OF DRILLMEC S.P.A).

5. XHoD Control System,

The XHoD Control System **Figure.22**, integrated in the HoD Manifold, gives operators the capability to easily manage and control the operative sequences related to connections with HoD in a safe and fast way.

The XHoD Software provides:

• real time influx and loss alarm, values and trends of mud parameters

• HoD Continuous Circulation System remote control and monitoring.

FIGURE 20: HOD® CCS MANIFOLD, (COURTESY OF DRILLMEC S.P.A).

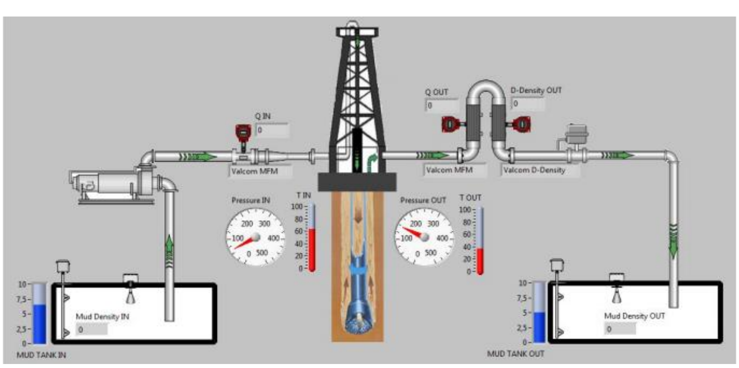


FIGURE 21: HOD® CCS XHOD CONTROL SYSTEM, (VALCOM®)

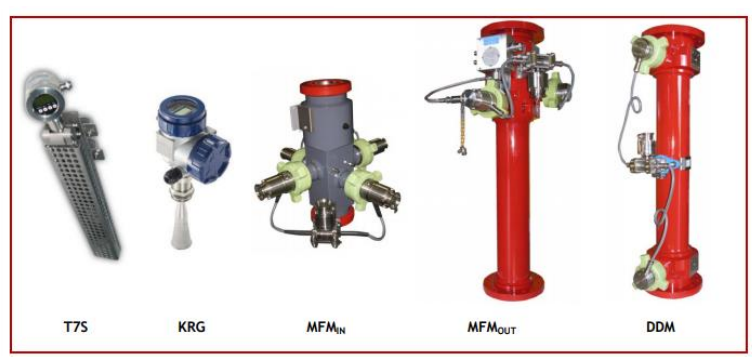


FIGURE 22: HOD® MUD FLOW METER FLOW MONITORING, (VALCOM®)

Challenges to solve by CCD:

1- **Drilling through Narrow Pore/Fracture Pressure window**

Using continuous circulation system will reduce the pressure surges that happen downhole when start/stop circulation conventional technique is used. And will keep the pressure at steady state at the dynamic value in the open hole section.

a. Surge and Swab pressure reduction

By having circulation in the well, while tripping in/out the hole. The effect of Surge and Swab is significantly reduced. IT can approach to zero with CCS deployment , if all drilling parameters are optimized.

b. Surging in start/ stop circulation elimination

In conventional drilling, when the pump stops. And due to the Thixotropic properties of the mud. The mud will build a gel structure. To start the circulation and to commence the drilling again that will need extra pressure to break that gel structure. The surge pressure to break the circulation after any connection is named Circulation breaking pressure. That surge pressure can break exposed weak formations in the open hole section.

By having continuous circulation in the well, that pressure surge to break the circulation is eliminated.

The following **figure.23** represent the pressure fluctuations recorded by PWD tools in case of conventional drilling, and how it would be minimized to the minimum if CCS CBHP MPD were utilized in the drilling process of this section

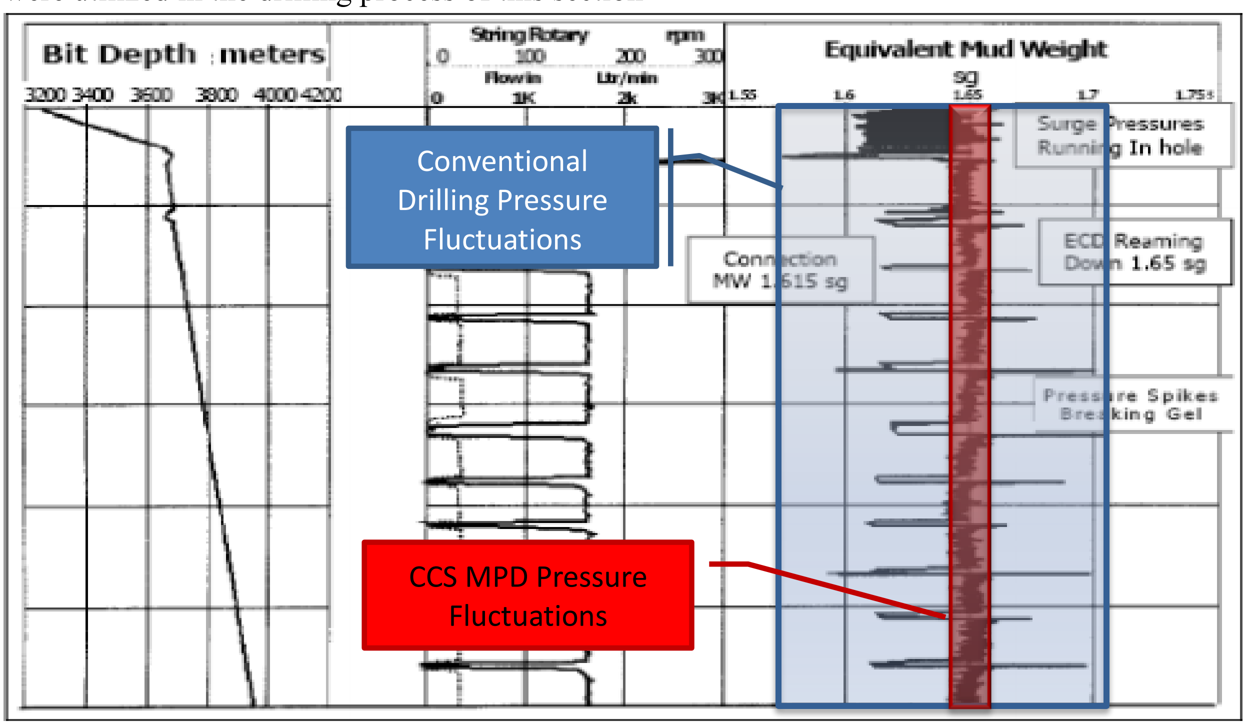


FIGURE 23: CONVENTIONAL DRILLING PRESSURE FLUCTUATIONS, (WARD C.D., AND ANDREASSEN E., 1997).

2- **Slugging and settling of cuttings**
By keeping the circulation ongoing, the settling of cuttings in annulus while making a connection will be eliminated. That, will provide optimum and continuous hole cleaning. Moreover, reducing the probability of having a mechanical pipe stuck.

3- **Differential sticking**
By utilizing CCS, The maximum pressure that will be present bottom hole will be reduced compared to the conventional drilling. Thus, the probability of differential sticking is reduced.

4- **ROP Improvement**
By having the ability to reduce the mud weight, the ROP will increase.

5- **ECD fluctuations and hole stability**
In conventional drilling, The open hole section of the well is exposed to a lot of pressure and ECD fluctuations. These ECD variations makes the hole unstable and may cause hole collapse and erosion, that will cause more stuck pipe and hole cleaning problems. But by having continuous circulation in the well and steady state conditions, these pressure changes are minimized.

6- **Connection Kicks**
As elaborated before connection kick, are expected in some statistical studies to make up around 70% of kicks that happen during drilling process.
When circulation stops, and due to the loss of the annular pressure loss, the connection gas increase. The open hole section might have a zone that has the mud gradient is lower than formation pressure in static conditions (But higher in dynamic). So having continuous circulation would reduce the risk of having kicks during connections.

7- **Pressure and Temperature Variations in HPHT wells**
The static condition of the mud during connection in HPHT wells would give more time for the heart exchange between the high temperature formation and the drilling fluid. That heat exchange would reduce the mud density and change its rheological properties. Having steady state circulation conditions inside the well would not allow that to happen.

8- **Formation Ballooning (Wellbore Breathing)**
When Dynamic pressure is higher than formation pressure, some of the drilling fluid volume is injected into the formation by the effect of that pressure difference. Ballooning is the ability of the formation to return these injected fluids when the well becomes static (i.e., ECD reduces due to the loss of dynamic circulation). That ability is mainly found in naturally fractured formations, due to the opening and closing of fractures with downhole pressure changes.

These returned volumes are misleading, and if not analyzed correctly, they can be considered to be a fluid influx from the formation. For example Well Bard-1, which is drilled in October 1998 in Timor Sea, offshore northwest Australia. The well had miss interpretation of the well bore breathing with formation influx and kick. By the end, that lead to abandon the well (Ashley,2000).
By having steady state circulation in the well bore and reducing the pressure maximum pressure to be applied in the well pore, the problem of wellbore ballooning can be eliminated.

Back Pressure Application

Surface Back pressure Application CBHP MPD method is the conventional and most widespread definition of MPD systems. The bottom hole pressure is kept constant and above formation pressure during any pipe connection by applying back pressure from the annular side in order to replace the annular pressure losses during connection making/breaking.

That system will need the utilization of Rotary Control Device (RCD) in a closed loop circulation system. RCD (also known as Rotating-BOP) are devices which are used to provide a seal around the drill string while it rotates, and are the main enabling equipment of closed loop MPD system.

The utilization of closed loop circulation, will give the MPD system the ability of underbalanced drilling fluid deployment.

The simplest form of applying back pressure from the annular side of the well while making a connection is done by the following steps:

1- The annular dynamic pressure losses is calculated based on the well and BHA models.
2- The amount of back pressure to be applied from the surface is decided and calculated, which will equal to the annular dynamic losses in order to keep the BHP constant.
3- For closing the pump or stopping the circulation from the well, the circulation is removed from the well in steps. That with each step, there will be a choke closing step to apply back pressure that would compensate for the pressure loss in the well. These steps continue until the complete stop of circulation and complete closing of the choke and choke pressure increase.
4- After connection is made, the circulation starts back in the well by the same stepping way. A choke closing/Opening schedule while making a connection is show in figures

That closing/opening schedule as the one shown in **figure.24** can be manual or automated process. The automation of the process will have higher efficiency and accuracy. The back pressure application can also be done by the help of a back pressure pump rather than a closing choke.

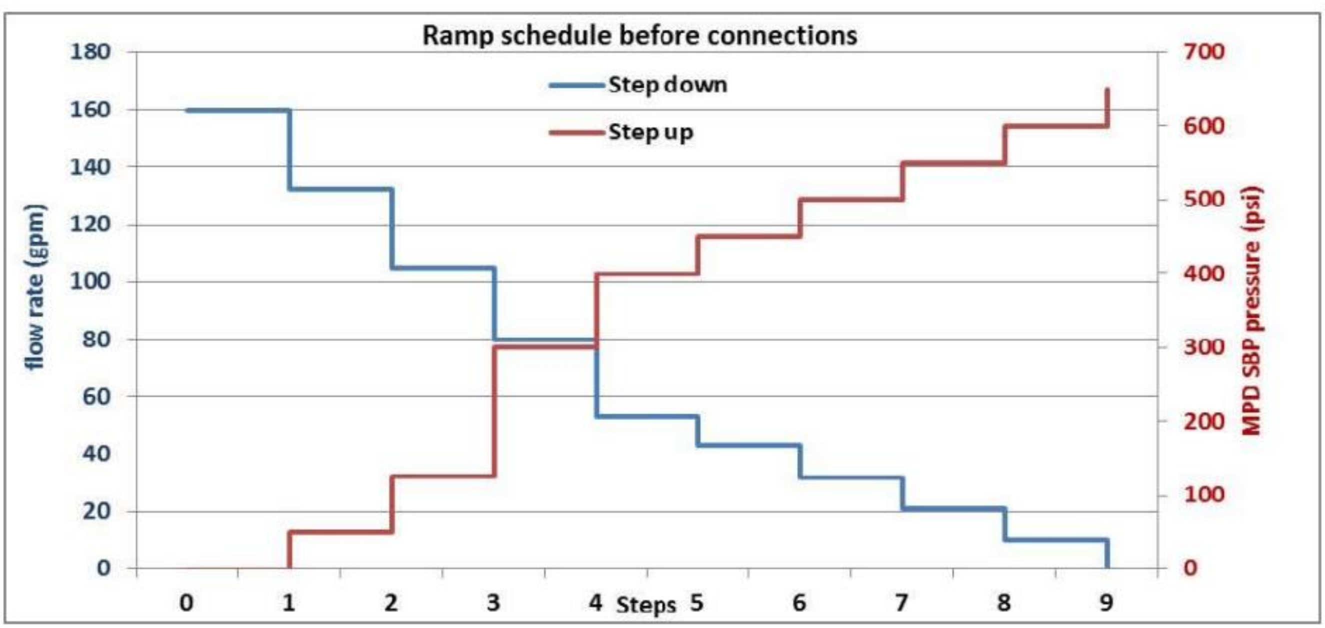


FIGURE 24: CHOKE CLOSING SCHEDULE IN MPD BACK ANNULAR PRESSURE APPLICATION, (OSEME U. ET AL.,2017).

Challenges to solve by Closed loop MPD system:

1- Having a constant ECD during connection.
   When losing the circulation, or stopping the pumps, back pressure is applied from the annular side in order to replace the loss of dynamic annular friction pressure losses.
   That will require, a fluid flow model in the annulus in order to be able to calculate the annular pressure losses with high precision.
2- Influx detection within short time.
   Due to the usage of closed loop circulation system, any influx /loss happen in the well will be detected instantaneously and with a high precision.
   That happen with utilization of Early kick/Loss detection skid, which
3- Instant control of Small amount of Influxes dynamically, without the need to stop the drilling operation or NPT.
   If the amount of the influx detected is controllable, back pressure would be applied from the annular side to stop the influx. Then, the kick can be circulated out of the well safely.
   The controllable volume of Closed loop MPD system would be based on a risk analysis study, that will revise the detection accuracy and robustness of the system response, and a creation of a well control matrix for quick decision making while in the drilling process as in **figure.25**.

MPD Drilling Matrix		Surface Pressure Indicator			
		At Planned Drilling Back Pressure	At Planned Connection Back Pressure	> Planned Back Pressure & < Back Pressure Limit	≥ Back pressure Limit
Influx Indicator	No Influx	Continue Drilling	Continue Drilling	Increase pump rate, mud weight, or both AND reduce surface pressure to planned or contingency levels	Pick up, shut in, evaluate next action
	Operating Limit	Increase back pressure, pump rate, mud weight, or a combination of all	Increase back pressure, pump rate, mud weight, or a combination of all	Increase pump rate, mud weight, or both AND reduce surface pressure to planned or contingency levels	Pick up, shut in, evaluate next action
	< Planned Limit	Cease Drilling. Increase back pressure, pump rate, mud weight or a combination of all	Cease Drilling. Increase back pressure, pump rate, mud weight or a combination of all	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action
	≥ Planned Limit	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action

FIGURE 25: MANAGED PRESSURE DRILLING OPERATIONS MATRIX WITH INFLUX DETECTION, (THE MINERALS MANAGEMENT SERVICE (MMS) GULF OF MEXICO OCS REGION (GOMR),2008).

4- Gives the ability of calculation of pore and fracture pressure while drilling, and the relative mud weight and ECD to be adjusted accordingly to the calculated and measure values.
5- The ability of deployment of statically underbalanced drilling fluid without risking the well primary barrier.
   The drilling fluid column can be designed to be statically lower than formation pressure and when circulation starts and with the annular pressure losses it will be slightly higher than the formation pressure. That will give all the benefits of lowering the bottom hole pressure while drilling (i.e., increasing ROP, lowering formation damage…..etc.).

Back Pressure Application Vs. Continuous Circulation CBHP MPD Techniques

The main challenging points that will define which CBHP will be more beneficial to the case that we are facing, require considering the main differences between the two systems.

The following **table.2** define the main operational differences between the CBHP MPD two systems in deployment:

TABLE 2: COMPARISON BETWEEN CONTINUOUS CIRCULATION DEVICES AND ANNULAR BACK PRESSURE CBHP MPD TECHNIQUES

Comparison point	Open Loop – CCS Continuous Circulation System	Closed Loop MPD system Annular Back Surface Pressure
Complexity of operation	Less Complex	More Complex
Experience needed	Easier for application	Harder for application
Rig modification	Minimal	Major Circulation System modifications
Well Barrier re-definition	NO re-definition. Exactly like the conventional	Barriers will be re-defined if underbalance fluid is used
Well control	No well control addition	Enhanced well control due to the presence of RCD
Offshore application	Not complex	More complex
Ability of underbalanced drilling fluid utilization	Will not be allowable because of compromising primary well barrier	Available, thanks to the presence of RCD.
Pressure Profile inside the well	Makes lower slope of the pressure profile inside the open hole section. Useful when the formations below are more stressed and higher in pressure than the formations above.	Makes larger slope of the pressure profile inside the open hole section. Useful when the formations below are less stressed and higher in pressure than the formations above
Utilization of Flux control and detection system	Available	Available.
Sophistication of calculations needed	Not a critical element in the drilling process.	A hydraulic well model update is critical and control is needed to calculate the needed surface back pressure at all times.

And the following **table.3** provides a summary about the challenges that can be solved by each of the systems.

TABLE 3: CHALLENGES TO BE SOLVED WITH EACH OF CBHP MPD TECHNIQUES AND THE COMBINATION

Challenge	CCD	Closed Loop MPD	Combined (CCD + RCD)
Narrow Pressure Window (PP/PF)	X	X	X
Wellbore Ballooning	X		X
High Pressure	X	X	X
High Temperature (Over Heating Protection)	X		X
Surge/Swab	X		X
Gel Strength Pressure mitigation	X		X
Extended Reach Drilling	X		X
Influx Detection and control		X	X
Drilling Gas (H2s)	X	X	X
Depleting Kicks		X	X
Hole Cleaning	X		X
Lowering the mud weight	X	X	X
Fluid Loss Mitigation		X	X
Calculation of Pore pressure and fracture		X	X
Underbalanced Drilling fluid deployment		X	X

From the previous comparison, the CCS is exceeding the benefits of Closed loop MPD system with respect to pressure fluctuations and wellbore stability. On the other side, Closed loop MPD system adds an extra element of control over the well.

Each of these systems is providing some benefits that the other system does not provide. Moreover, these benefits are not mutually exclusive. That means both systems can be combined to have a full CBHP MPD package. CCS which will be able to mitigate a huge number of drilling problems that happen due to downhole pressure ECD fluctuations, and the closed loop system by the extra control over the well and underbalanced drilling fluid utilization ability in safe conditions. Moreover, as a sort of a backup system when circulation dynamic pressure losses is lost.

Thus, combining both systems will provide a full CBHP MPD system that will be able to face a large number of the drilling issues in the most extreme and critical conditions.

Eni Near Balance Drilling e-nbd^{TM} system

One Example of the systems available in the market is Eni Near Balance Drilling (e-nbd^{TM}) system. That system is a combination between Back Pressure Application technique and continuous circulation devices (e-cd^{TM} Eni-Circulation devices CCS).

e-nbd^{TM} had been deployed multiple times in order to allow more safe drilling operation in narrow pressure window and tight well conditions and environment. The system had been utilized and tested in Land rigs, offshore Platforms, and offshore floating drilling vessels.

Provided the following study (Squintani et al.,2018) and observations in two wells, well A and Well B.

Well "A" : CCS and the need to go underbalanced!

"Well A" is an offshore well drilled from a drillship with water depth higher than 2200m. The expected pressure window is from 0.17 to 0.08 kg/cm2/10m. The e-cd^{TM} CCS had been deployed in that well in order to reduce pressure fluctuations in such expected tight pressure window.

The well reached an extremely tight and strict condition more critical than the expected. The available pressure window was ranging from 0.13 to 0.02 kg/cm2/10m. that the drilling fluid had to be statically underbalanced in order to make the dynamic pressure downhole ECD inside the drilling window Fig. Shows the dynamic and static mud window. The recorded static and dynamic pressure data while drilling the well is shown in **figure.26**.

The application of e-cd^{TM} CCS with underbalanced static mud weight was vital and critical condition, and unstandardized way of operation, that the drilling fluid static mud weight pressure had been slightly lower than formation pressure for a part of the drilled open hole section. That critical condition had been made safer and more assured in "well B" by the addition of RCD and utilizing closed loop system.

Well "B" : Utilization CCD in a closed loop MPD system Configuration, e-nbd^{TM}

"Well B" Is an offshore well, with a water depth of 850m. The well had been drilled originally utilizing only closed loop Back Pressure Application MPD system without CCS. And due to a multiple number of well control problems, the well had been considered not safe to be drilled to the total depth, and decision taken to be abandoned.

Later on, ENI S.p.a, had decide to re-enter well "B", but with e-nbd^{TM} system, To be able to drill the well without down hole pressure fluctuations that caused a lot of problems in the original hole, and the MPD closed loop system with the choke manifold in order to be able to use underbalanced drilling fluid safely without compromising the primary barrier of the well.

That system proved to be successful in such ultra-tight pressure window conditions of 0.05 kg/cm2/10m. That either of the systems cannot complete the job individually. That MPD system alone had not been able to go through this tight pressure window condition, and CCS will require an underbalance drilling fluid which will compromise the primary well barrier policy.

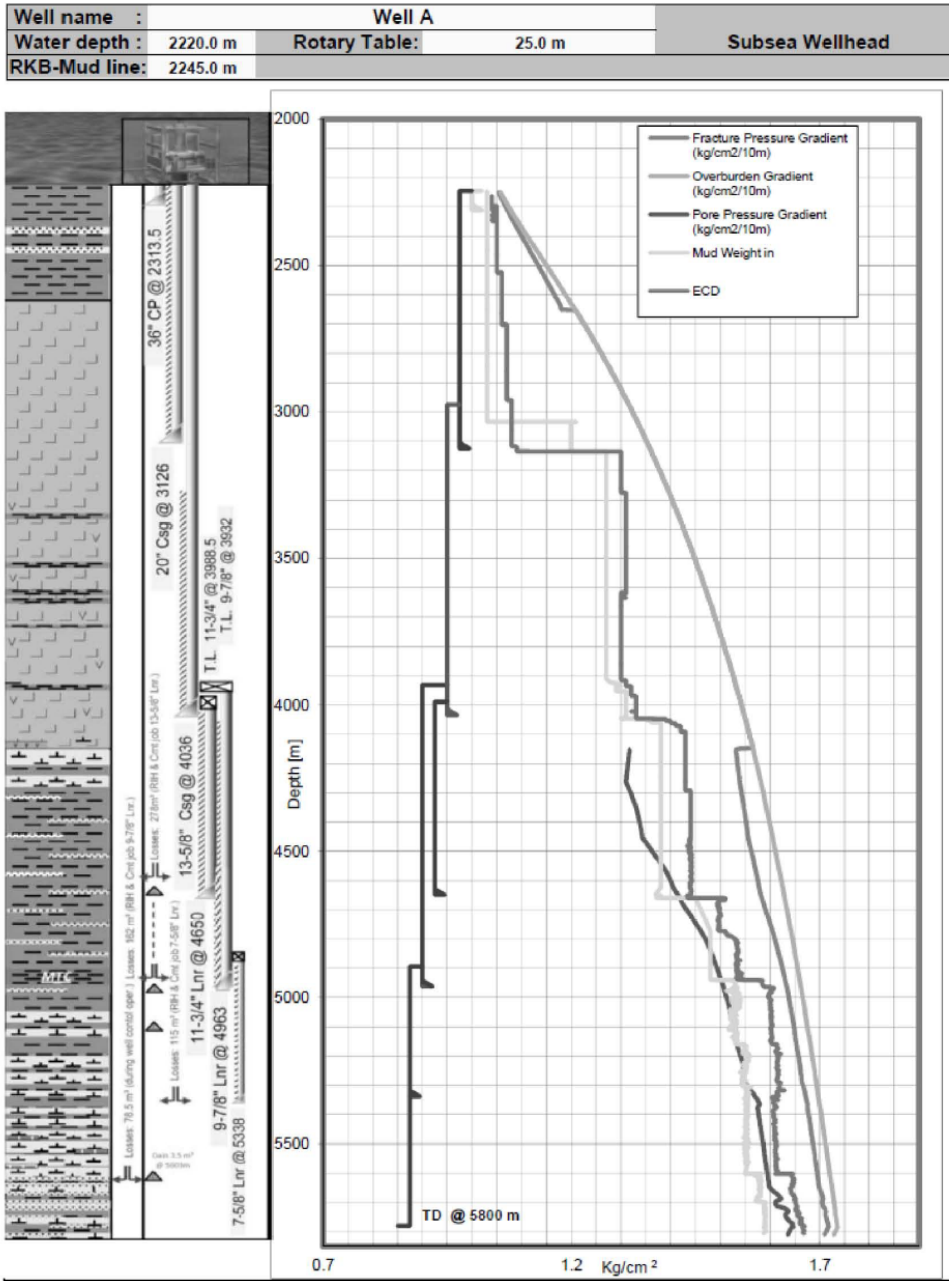


FIGURE 26: WELL "A" ACTUAL DRILLING DATA, (SQUINTANI ET AL.,2018).

Early Kick/Loss Detection (EKLD)

Kick detection time is one of the most important Key performance indicators (KPI) related to kicks is the time needed to identify a kick. As detection time reduces, as the response will be faster, as the kick volume reduces, and the severity of severity of the situation will be less.

Early Kick/Loss Detection (EKLD) (or sometimes named as MicroFlux Control MFC System) mission is to provide a fast identification of kicks or circulation losses at very small volumes, that will aid in the well control mitigation process as early as possible. That system can be utilized in the operation conventionally or with any MPD system without interfering with its operation, on the contrary this system is able to make the process more efficient.

Furthermore, EKLD system helps to monitor potential changes to the BHP and the well circulation system. Helping to identify and to differentiate kicks and losses from downhole events as ballooning and breathing, these events those could be miss-interpreted, and cause escalation of problems in the drilling operation if the problem is treated with wrong interpretation.

EKLD system is a combination of sensors and flow meters. That have the mission to monitor the inflow and outflow from the well, and by this monitoring and comparison between them any influx or loss will be detected and analyzed promptly.
Flow meters can be Coriolis or Venturi meters. Some of challenges will be met for the system to be applied in open loop circulation system as:

- Coriolis meters require head pressure, which might not be present in most of open loop circulation operations (non MPD) circulation systems. Anyways, the required head is not high (~3-5 psi).
- Coriolis meters are very sensitive, that the rig heave and pump stopping/ starting operations would change the meters reading s noticeably. So Noise reduction techniques and software are utilized to increase the confidence in the meter readings. In open loop conventional drilling a characterization and description of the outflow transient patterns would be needed to help to help to identify and confirm the presence of kicks.

EKLD system can be utilized in either open loop or closed loop circulation system, but when in closed loop circulation system it can be connected to the remote choke by a processing unit and a control panel that will give it the ability to act proactively depending on real-time analysis. For example within few seconds of kick detection and confirmation the system can give an order to the remote choke to ably back pressure that will reduce any further influx in the wellbore. And vice versa, The same can happen with mitigation of partial losses.
The following simple workflow (**figure.27**) can provide an explanation of the EKLD system with remote choke MPD system.

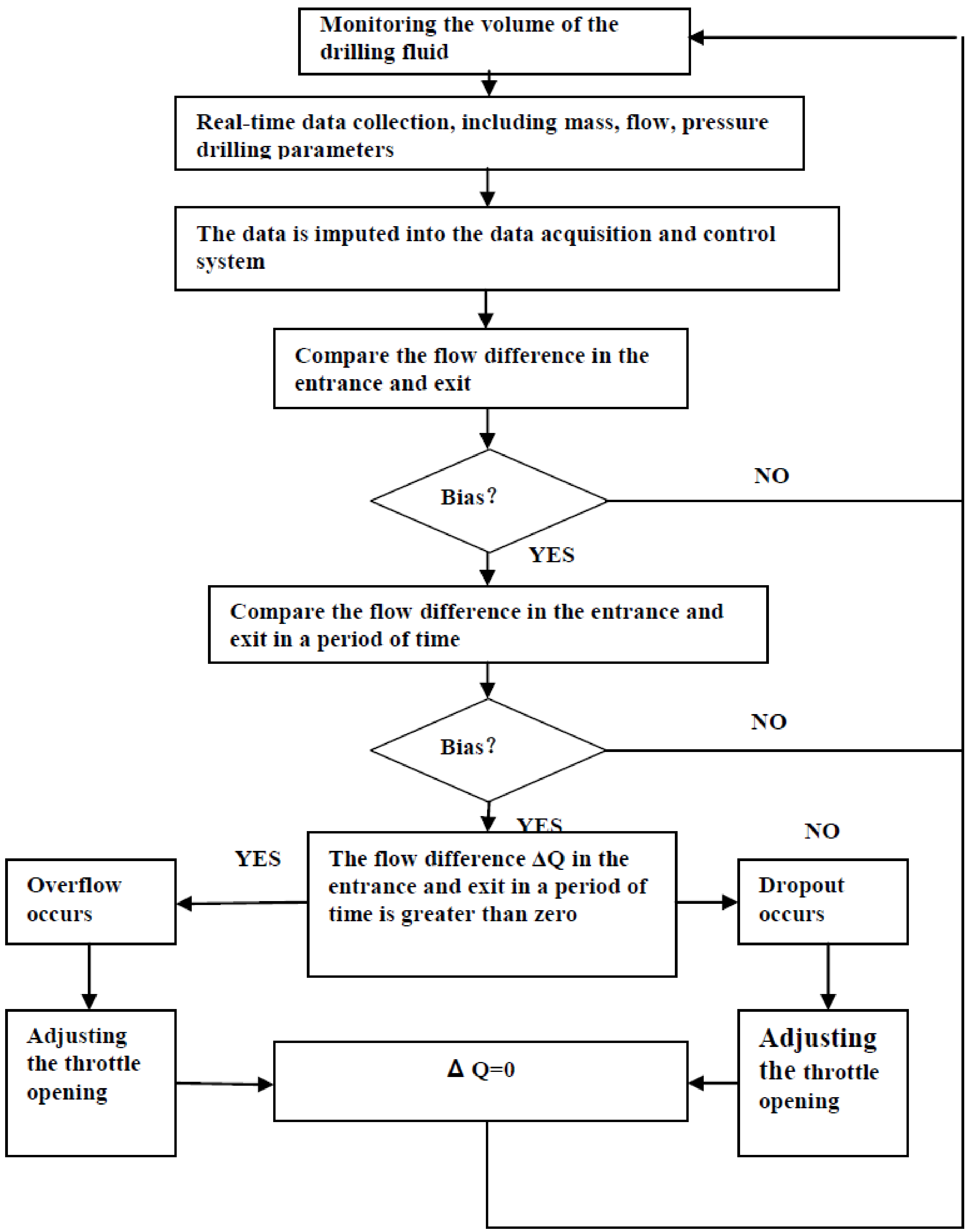


FIGURE 27: PROCESS OF MICROFLUX CONTROL, (JIANG ET AL.,2014).

A case study made by Calderoni A., and Girola G. et al.in 2009, proved that the combination between the MFC + CBHP MPD systems are beneficial in harsh and challenging situations.

The study was made to know the effect of Micro Flux Control MFC System utilization, in drilling in challenging HPHT offshore well, in Mediterranean, in Egypt.

The system had been utilized in two configurations:

- **Combining the MFC system with e-cd™ Continuous Circulation System.**
  But the feature of automatic control of the well is off, and if kick is detected the well will be controlled by the conventional well control operations.

- **Combining the MFC System with e-nbd™ Combined CBHP MPD system.**
  In that case to drill in a tight hole section, the automatic control system is online and able to control the well by the applied back pressure as explained before.

The following **figure.28** Provides a comparison in the operation with and without MFC system, in terms of Time, Number of Kicks, Size of Kicks, and NPT .

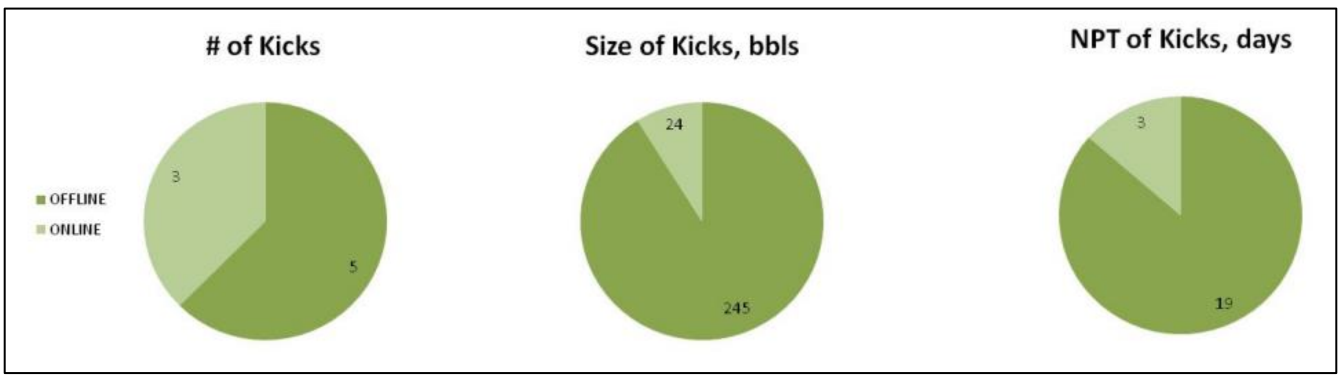


FIGURE 28:NO. OF KICKS, SIZE OF KICKS, AND NPT OF KICKS, WITH AND WITHOUT MFC SYS., (CALDERONI A., AND GIROLA G. ET AL., 2009).

The MicroFLux Control system combination with the CBHP MPD Techniques proved that it is very beneficial in identification of kicks early enough to reduce the time required (i.e., NPT) to regain control on the well (from 19 days to only 3days) and reducing the severity of the situation, and making it safer mood of operation by reducing the number, and sizes of kicks (from 245 bbls to only 24 bbls).

Case Studies

The following two wells had been drilled with the utilization of HoD™-Drillmec, open loop CCS:

Case Study #1 OPEN Loop CCS: onshore Appraisal well in Central Europe

The HoD system had been used in the drilling phase of 12”1/4 hole for well “~~S~~[redacted]~~3~~” confidential , which is drilled in Axxxxxx by Sxxxx. confidential (**table.4**).

TABLE 4: **SXXXXXX-3** CONFIDENTIAL WELL DATA, (COURTESY OF DRILLMEC S.P.A).

Drilling phase:	**12”1/4**
Lithology:	90%Claystone/Shale and 10% Siltstone/Limestone
Start Depth:	3,600 m
Final Depth:	5,300 m
Mud Type:	WBM
Mud Weight:	1.86 – 1.93 sg
Flow rate:	735 - 900 gpm
SPP:	3,700 – 4,200 psi
HoD Sub:	OD7’’ - 5’’1/2 FH - SS105
Service days:	90
Connections:	266
CHALLENGES	Stuck pipe, pack offs with several NPT and even more often low ROP due to high wellbore instability and poor hole cleaning.

Situation discerption:

There were two Pull out of hole POOH operations with the same BHA, one in the conventional way of stopping /starting circulation, and the other with the utilization of HoD CCS system. The comparison of problems encountered during these two POOH operations will provide an insight on the benefits gained by HoD® CCS.

Figure.29 show the Stuck events and problems encountered with both POOH operations. The left chart shows POOH #1 in which CCS had been utilized several times. In the left is the POOH #2 in which CCS is not utilized.

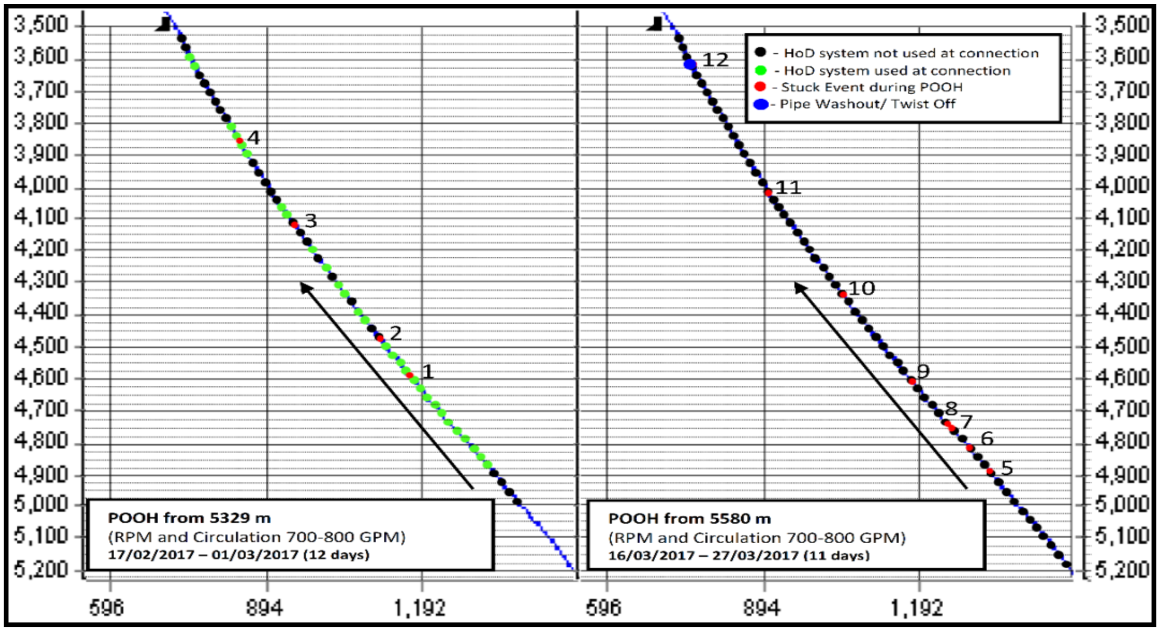


FIGURE 29: STUCK EVENTS AND COMPARISON BETWEEN THE OPERATION WITH AND WITHOUT HOD® SYSTEM UTILIZATION, (COURTESY OF DRILLMEC S.P.A).

Analysis of the collected data:

- During POOH with HoD® utilization five stuck had been observed with total NPT time of 57 hrs, compared to 102 hrs without HoD utilization at the same depths.
  The main reason for the pipe sticking was hole tightening and shale swelling and collapse (Proved by the cutting return on shale shaker)

- There are two stucks which happened at the same depths while using HoD and while not using it. Those can be used for a direct comparison in **table.5**.

TABLE 5: STUCK MITIGATION WITH AND WITHOUT HOD®

Event	Depth MD/TVD (m)	HoD	Time to release the string
Pipe Stuck	~4556m/4337m	**Yes**	**0h30min**
		No	3h22min
Pipe Stuck	~4837m/4588m	**Yes**	**0h49min**
		No	36h03min

Observed Benefits of CCS deployment:

- The total NPT due to pipe stuck at POOH operations is reduced by around 50%
- Due to better hole cleaning and hole conditions, the time required to free the drill string is significantly less.
- The volume of the friction cuttings in case of CCS utilization is much lower (around 50% of the conventional POOH), which proves a better hole cleaning conditions, and avoiding cuttings build up in the annulus.

Case Study #2 OPEN Loop CCS: offshore exploratory well in BlackSea

Well name : Mxxxx-1 confidential , well data are in **table.6**

Operator : Rxxxxxx and xxI confidential

TABLE 6: MXXXX-1 CONFIDENTIAL WELL DATA, (COURTESY OF DRILLMEC S.P.A).

Drilling phase:	17”1/2
Water Depth:	2,109 m
Start Depth:	2,790 m
Final Depth:	4,899 m
Mud Type:	OBM
Mud Weight:	1.11 – 1.46 sg
Flow rate:	3800-4200 l/m (max)
HoD Sub:	OD 7” – TT585 – S135
Subs in hole (max):	40
Service days:	58
Connections:	194
CHALLENGES	Calculated PPFG profile has a high level of uncertainty due lack of calibration wells and seismic velocity anomalies due to gas effect. Possible narrow window require a close control of the ECD and borehole cleaning to avoid potential kicks and/or mud losses.

Analysis of the collected data:
HoD (Heart of Drilling) has been included in the drilling program starting from 17 ½ phase to enable continuous circulation during the connection in order to control downhole pressure by having a constant ECD at all times.
And there are recorded pressure data by MWD tool in **figure.30**.

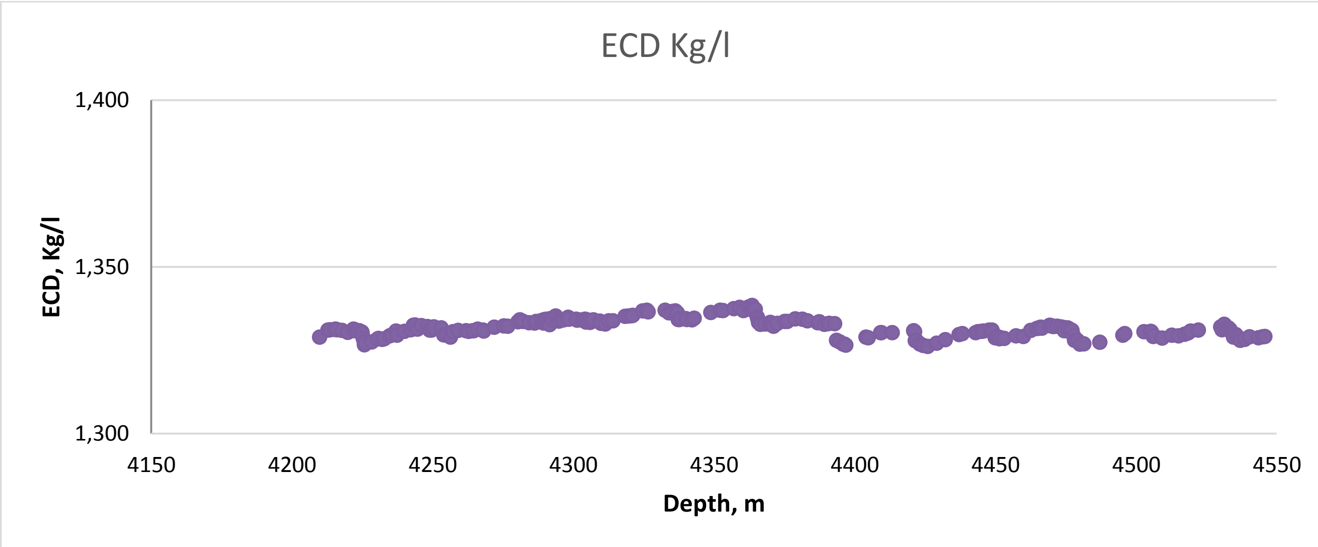


FIGURE 30: MXXXX-1 CONFIDENTIAL, RECORDED ECD DATA WHILE UTILIZING HOD®, (COURTESY OF DRILLMEC S.P.A).

Observed Benefits of CCS deployment:

- The variation with the ECD is only **± 16 psi (±0.021 ppg)**
  HoD® CCS helped in keeping the bottom hole pressure constant during connection with the minimal pressure surges due to piston effect (i.e., Surge/swab).
- HoD® system utilization did not increase the time needed to make a connection.
  The average connection time is Connection time: 00:12:32, which is the same with or without HoD® system.

Chapter 3: Well Integrity with MPD

Basics of well integrity

Based Norsok D-10, the definition of well integrity is the "Application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well".

So it is the application of operational and structural methodologies to maintain control on the fluid movement from/to the formations in the well bore in the whole life of the well starting from the planning and well spudding phase to the plug and after the abandonment phase

while studying the part of well integrity with MPD systems we are concerned with the drilling period of the wells life.

The concept of Well Barriers:

Well barriers are the basic components of the well integrity system, that prevent any uncontrolled flow of formation fluids to the surface or even to another formation.

Based on Norsok D-10 Definition :

"Well barriers are envelopes of one or several dependent Well Barrier Elements (WBE)s preventing fluids or gases from flowing unintentionally from the formation, into another formation or to surface."

Barrier Specifications:

The exact type, number, and specifications of well barriers have to be defined at each stage of the well life cycle.

Number of Barriers needed in the well:

One Barrier Policy, Should be used at the following cases:

- Cross Flow between different zone should be prevented.
- Normal Pressure zones that doesn't have hydrocarbon, and are not able to produce its fluids to the surface.
- Abnormal pressure Hydrocarbon zones which is not able to flow its fluids to the surface.

Two Barriers Policy, Should be used at the following cases:

- Hydrocarbon Bearing Formations.
- Abnormal pressure zones that are able to produce its fluids to the surface.

Acceptance criteria of well barriers

By reviewing Norsok – d10r4, the acceptance of well barriers during drilling operation will be as following:

General well barrier acceptance criteria:

1. Two independent Barriers at least has to be present to prevent any uncontrolled flow from the formations.
2. Well barrier should be able to Shut in the well on direct command during an emergency shutdown situation and thereby prevent hydrocarbons from flowing from the well.
3. In case of a loss of one barrier, the other barrier should allow, and aid the process of regaining the control on the well again.
4. In case of a loss of one the barriers, there must be an immediate plan to reconstruct it again. And barrier reconstruction to be the highest priority operation to be done versus any other operation.
5. The barriers shall be defined and criteria for (what is defined as a) failure shall be determined.
6. Status of all barriers has to be well defined, checked, and maintained all the time.
7. There must be a testing criteria for the assessment of degradability or potential failure risks within the defined barriers.

General acceptance Criteria of Drilling Fluid as a Barrier in the wellbore:

1. The hydrostatic pressure shall at all times be equal to the estimated or measured pore/reservoir pressure, plus a defined safety margin (e.g. riser margin, trip margin).
2. Critical fluid properties and specifications shall be described prior to any operation.
3. The density shall be stable within specified tolerances under down hole conditions for a specified period of time when no circulation is performed.
4. The hydrostatic pressure should not exceed the formation fracture pressure in the open hole including a safety margin or as defined by the kick margin.
5. Changes in well bore pressure caused by tripping (surge and swab) and circulation of fluid (ECD) should be estimated and included in the above safety margins.

For MPD operations, in “Norsok-d10” MPD Operations are defined to be done by using an underbalanced drilling fluid. That underbalanced fluid will affect the integrity of the primary well barrier which is the drilling fluid, so additional approaches and modifications with regard to the conventional has to be utilized to re-set the primary barrier again.

1. The RCD Should be installed above BOP Stack.
2. A special dedicated MPD Choke Manifold is used to control the annular pressure from the surface. Moreover, have the mission of reducing the drilling fluid pressure before entering to the separation equipment or Shale shakers.
3. A continuous influx from the formation should be prevented at all times.
4. The degradation of any of the surface equipment should not affect process of well control.
5. During Tripping operation the applicability to measure any surface pressure should be available, either by a direct measurement if the RCD is installed, or the fluid level in the annulus if there is no RCD.
6. The surface system should be designed in such a way to be ready to handle any formation fluid influx.
7. Snubbing equipment should be used in any pipe light operations.
   Pipe light scenarios are snubbing (Running the drill pipe in how with BOP closed) operations when the buoyancy forces and wellhead pressure will have a total resultant forces higher than the weight of drill string, which will result in pushing the drill string out of hole rather than allowing it to go down by the effect of its own weight.

For the second barrier policy, it will be the same as conventional Drilling, which is the BOP.

Barriers Definition with respect to CBHP – MPD approaches:

The well barriers acceptance criteria in MPD application in NORSOK D-10 is based on the usages of underbalanced drilling fluid. That is the reason of installing RCD in the surface in order to give the ability to apply back pressure from the annular side and to keep the primary barrier of the well intact.

But if the drilling fluid is still overbalance (Statically and dynamically) with respect to the formation pressure, the conventional barrier acceptance criteria applies.

So as a summary for both major CBHP techniques:

The key factor that will decide the need for RCD (i.e., closed loop circulation system) and to go more complex than the conventional open loop circulation drilling criteria is the static mud weight with respect to the formation pressure in the section to be drilled:

1- **If the drilling fluid is Overbalanced $P_h > P_f$**
   The applicable systems are: CCD, Closed Loop Back Pressure System, or the combination.
   As the static Hydrostatic Head of the mud is higher than any anticipated formation pressure; the first conventional primary Well Barrier (i.e., Drilling Fluid) is not compromised. That leads to the same barrier configuration as the conventional drilling.
2- **If the drilling fluid is underbalanced $P_h < P_f$**
   The only applicable system is: Closed Loop Back Pressure System, or the combination.
   The static Head of the mud will be lower than the formation pressure, the applicable acceptance criteria will be the Norsok D-10 MPD Criteria.

Chapter 4:

Drilling Approach Selection Scheme (DASS) for CBHP MPD techniques

If MPD systems are utilized, where they are not needed; that will be an unneeded burden on the drilling process; accompanied with adverse effects on cost and time rather than reducing it. A thorough study will be needed in the well planning process to know the exact positive and negative effects of the utilization of MPD approaches.

Drilling Approach Selection Scheme (DASS), is basically a series of hydraulic calculations followed by data analysis steps that work as a preliminary decision making tool for the optimization of drilling technique selection process. DASS is focused to provide a decision tool about the need to CBHP MPD techniques in well drilling process.

CCD had proved its ability to provide a good control over the BHP and pressure profile while drilling, that annular back pressure application MPD system alone will not be able to provide.

In DASS approach CCS will be the main system to be used to provide CBHP in MPD application. The main choice to be studied between the utilization of **CCS in open loop or closed loop circulation systems.**

DASS is developed to give a decision for the usage of one of the following approaches in drilling:

1- Conventional drilling.
2- CCS In Open loop circulation (CCS).
3- CCS In Closed loop circulation (Adding RCD).

The Basic data needed to be collected for the start of DASS process:

- Planned Well Geometry
    a. Drill String and Bottom Hole Assembly (BHA) Definition.
    b. Casing Strings Definition.
- Predicted Pressure Profile
    a. Fracture Pressure Profile.
    b. Formation Pressure Profile.
- Drilling Parameters
    a. Circulation Rate.
    b. Drill string movement velocity while tripping in or out.
    c. Mud Rheology.

The analysis process starts with a hydraulic simulation of the wellbore while drilling, in order to calculate:

- Annular pressure losses.
- Surge Pressure due to pipe movement.
- Gel strength breaking Pressure.
- Drill string Acceleration/Deceleration pressure spikes.

After completing the hydraulic calculations, a simple workflow to be followed to know the optimum approach to drill the well. The calculations in the hydraulic simulator and the basics behind the workflow are explained in the following section.

Data Analysis and Decision Making Workflow

Background

It had been elaborated that utilizing CCS and CBHP approaches in drilling the wells, will provide a lot of benefits regarding hole cleaning and wellbore stability. The proposed DASS workflow is taking a fit-for-purpose approach, and providing simple and quick, yet precise way to aid to decision making process regarding MPD system deployment.

The DASS workflow is mainly based on defining the application limits of the two major CBHP MPD techniques, Open loop CCS, or MPD (CCS+RCD) closed loop. The classification of the CBHP MPD systems is mainly based on the hydraulic calculations and well integrity.

The main idea of DASS workflow is to start the study with the simplest system and lowest in complexity, which will be the conventional drilling, passing by the other a bit more sophisticated system but not with high complexity which is open loop CCS MPD, till the most complex system that require redefinition of well barriers and high expertise, the Closed Loop BP MPD system. That workflow will depend mainly on how wide is the available pressure window between formation pressure and fracture pressure along the drilled section in the well. And to assess if that window will be able to accommodate all expected pressures that might occur in the wellbore during drilling without having issues.

It had been elaborated in the hydraulic calculations part that the general downhole pressure expression is

$$BHP = P_h + P_a + P_{SS} + P_{GS} + P_{acc} + P_{Cl}$$

- P_h, Hydrostatic Mud pressure.
- P_a, Annular Friction pressure losses.
- P_{SS}, Surge and swab pressures (Due to Piston Effect).
- P_{GS}, Gel Strength breaking surge pressure;
- P_{acc}, Drill string inertial surge pressures .
- P_{Cl}, Surface Choke line back Pressure.

And based on well operations and drilling parameters, the minimum and maximum limit of BHP can be defined.

In transition from static to dynamic, $BHP = P_h + P_a + P_{GS}$

In dynamic conditions, $BHP = P_h + P_a$

Tripping in/out (Surge/Swab), $BHP = P_h \pm P_{SS}$

The DASS methodology based on the quantification of the minimum pressure window required to be present in the section that to be drilled. So it will require using a hydraulic simulator to calculate all of these terms that will be utilized with its different combinations (i.e., depending in well operation) in the screening process.

The following section provides an analysis of the pressures that might be present in the well with different drilling approaches and defining the pressure limits requirements in each of them.

Required Pressure Window with Conventional Drilling:

The required pressure window is explained in the following **figure.31** At the operation of tripping in /out the well, the effect of the surge and swab will be present in the well. Which will cause decrease of increase with respect to the hydrostatic pressure respectively. After making a connection and restart the circulation, there will be a pressure peak due to gel strength breaking, then the pressure will stabilize with the addition of the annular pressure losses part only.

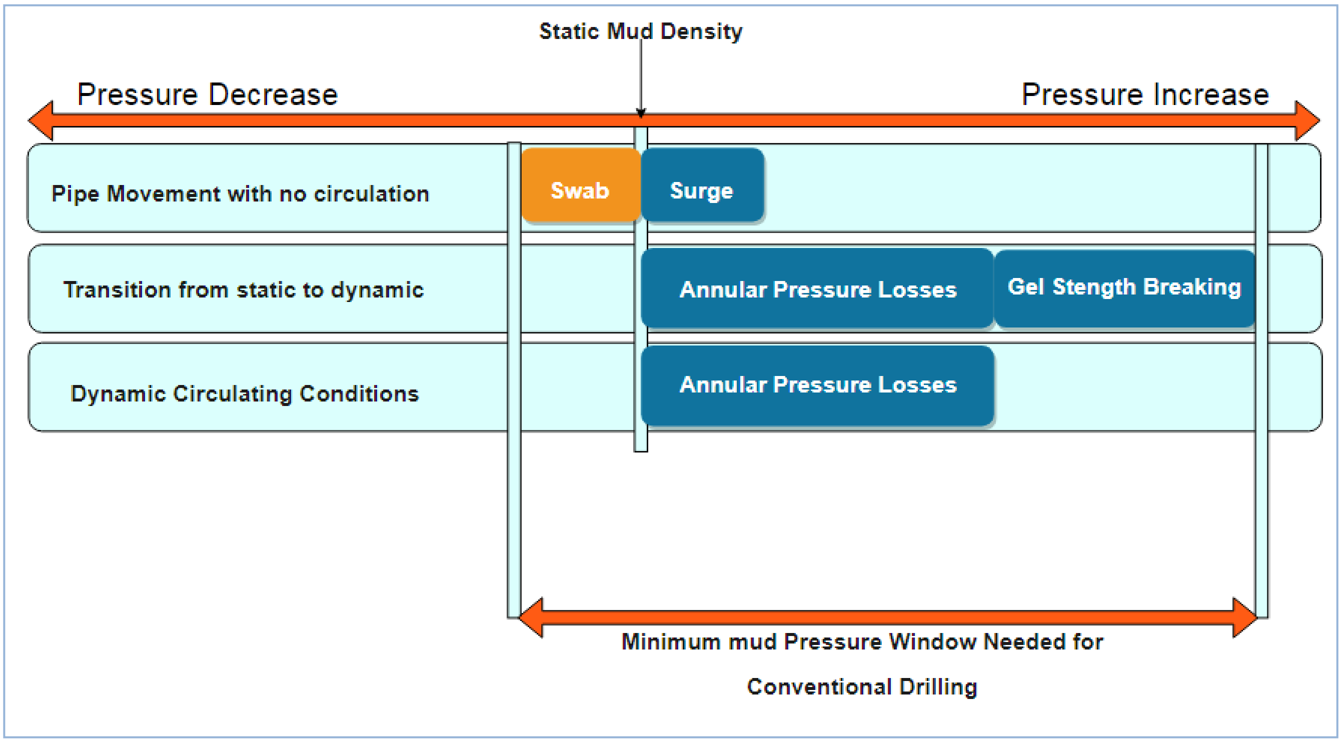


FIGURE 31: MUD WINDOW NEEDED IN CONVENTIONAL DRILLING APPROACH

The minimum pressure window to accommodate all of the well operations in conventional drilling approach can be quantified as, $\Delta P_{Conventional}$:

$$\Delta P_{Conventional} = Annular\ Pressure\ Losses + Surge\ Pressure + Gel\ Strength\ Breaking$$
$$= P_a + P_{SS} + P_{GS}$$

Thus, if the pressure window between the fracture pressure and formation pressure is larger the minimum pressure window needed,

$$\Delta P_{Conventional} < (P_p - P_F)$$

The well can be drilled conventionally, from pressure and well integrity point of view.

Required Pressure Window with CCS:

In case of using open loop continuous circulation system (i.e., without using RCD, and the casing pressure at the surface is the atmospheric).

Utilizing CCS open loop system will affect the pressure profile and pressure surges in the well, by several ways:

- The gel strength pressure beak after each connection will be eliminated, as it is not expected that the well will become static to make/Break connections.
- The Surge/Swab Pressure will be reduced due to having circulation while tripping in/out the well.
- The probability of having a kick while tripping out the drillstring is nearly eliminated as show in **figure.32**, as the pressure downhole with the swab effect is not expected to go lower than formation pressure.

Moreover, a surge/swab sensitivity analysis can be used to optimize the circulation rate while tripping. If optimized, the surge/swab pressures can approach to zero.

The following figure will show how the pressure window required is reduced when utilizing Open Loop CCS MPD system.

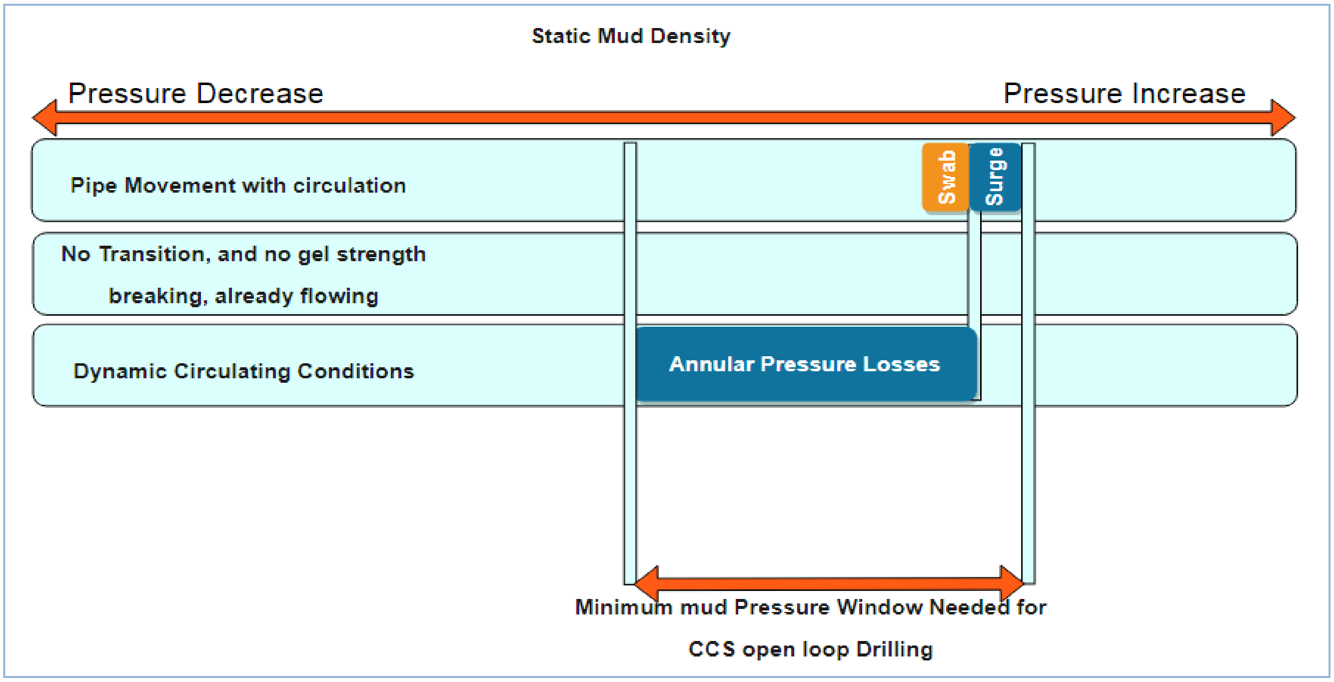


FIGURE 32: MUD WINDOW NEEDED WIH OPEN LOOP CCS UTILIZATION

The minimum pressure window to accommodate all of the well operations in Open CCS MPD approach can be quantified as, ΔP_{CCS}:

$$\Delta P_{CCS} = \textit{Annular Pressure Losses} + \textit{Optimized Surge Pressure}$$
$$= P_a + P_{SS}$$

Thus, if the pressure window between the fracture pressure and formation pressure is smaller than minimum pressure window needed for conventional drilling, but larger than annular pressure losses.

$$\Delta P_{CCS} < (P_p - P_F) < \Delta P_{Conventional}$$

The recommended method for drilling the well will be: by using CCS in an open loop configuration.

Required Pressure Window with Closed Loop MPD System:
In extreme conditions, where the pressure window is extremely narrow. That it becomes even smaller than the annular pressure losses. Removing or reducing pressure surges by deploying continuous circulation system alone will not be enough to drill the well section safely.

$$(P_p - P_F) < P_a$$

If we used a drilling fluid that has a static density equal to the formation pressure, mud circulation will make the pressure downhole exceeds the fracture pressure, compromising the safety and well integrity.

The solution to drill in these conditions is by using statically underbalanced drilling fluid

Having this underbalanced drilling fluid will require the utilization of closed loop CBHP MPD system. That at any time the well becomes static, a surface back Pressure can be applied, and the primary barrier of the well is not compromised.
The utilization of CCS in addition to RCD and surface choke will give all the benefits of CCS on downhole pressure surges plus the additional control on the well by the closed loop system.

The following figure will show how the well profile will be in static and dynamic circulation conditions.

Based on that, the following Chart (**Figure.33**) can explain the limits of each of the three systems with respect to the pressure window between fracture pressure and formation pressure in the section to be drilled.

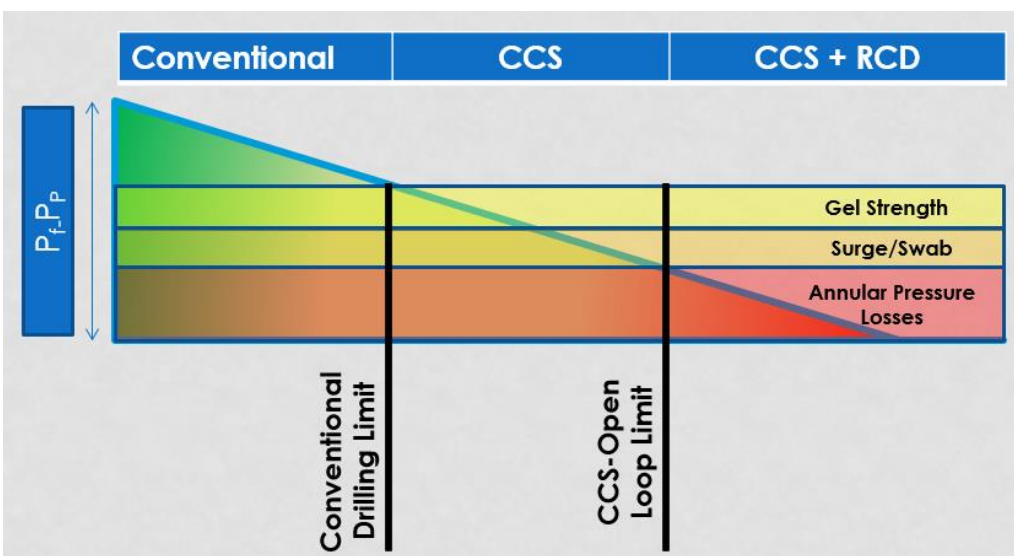


FIGURE 33: CONVENTIONAL AND CONTINUOUS CIRCULATION SYSTEM APPLICATION LIMITS

DASS Workflow Development

Based on the explained background the DASS workflow had been developed for the decision making and screening process regarding CBHP MPD system. The whole DASS operation start with hydraulic calculations

DASS workflow ends up giving a recommendation for one of three options:

1- **Conventional Drilling.**
   When the drilling window is big enough to accommodate all pressure fluctuations in the conventional drilling process, there will be no need for the utilization of any MPD system.

2- **Continuous Circulation System is recommended.**
   When the available pressure window is not able to accommodate all pressure fluctuations in the conventional drilling process. But, it is larger than the annular pressure losses.
   The deployment of CCS in an open loop mud circulation system will be the best and less complex option to solve any drilling issue that might arise from that tight pressure window.

3- **Closed Loop System + Continuous Circulation System (CCS +RCD).**
   When the Drilling window is ultra-tight, that its smaller than the annular pressure losses, and the use of underbalanced fluid is mandatory. Thus, a CCS will be utilized to minimize the pressure fluctuations to the minimum, and RCD with a choke manifold will be added to the system to maintain the primary barrier policy of the well.

Based on the previous explanation the workflow in **figure.34** had been developed .

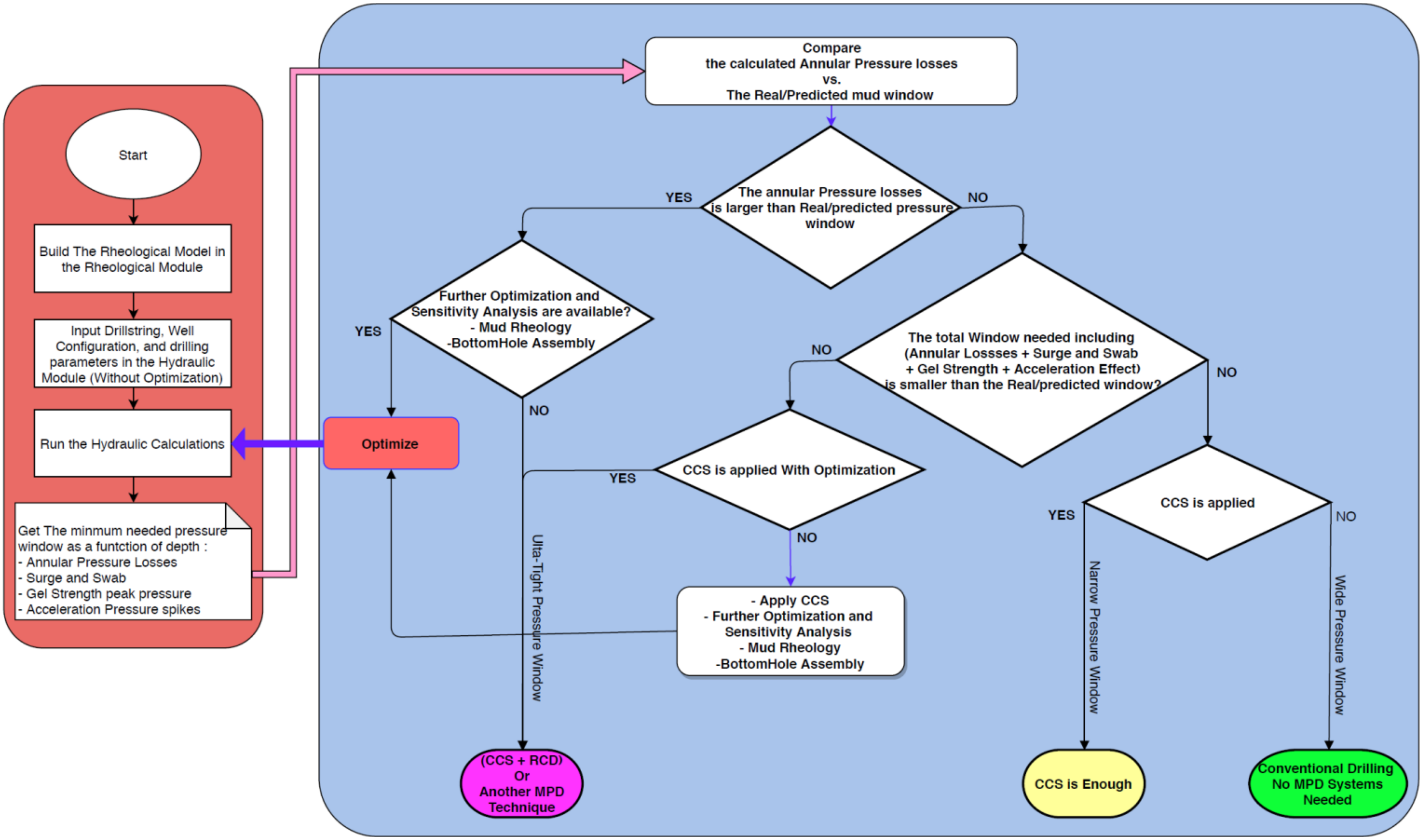


FIGURE 34: DASS WORKFLOW

DASS Hydraulic Simulator

A steady state hydraulic simulator had been developed for DASS process. The hydraulic simulator is a Visual Basic For Applications (VBA) based software embedded with an Excel Sheet.

This section will provide an explanation of how the hydraulic calculations are made inside the simulator.

Hydraulic Simulator Missions:

- Evaluation of different Rheological models and helps in selection of the best rheological model that match the rheology of the mud used in the drilling process.
- Calculate the pressure losses in the annular space for the mission of calculation of ECD.
- Calculation of Surge/Swab pressure surges.
    - The optimization of the tripping speed.
        - Not too slow, that the NPT will be higher.
        - Not too fast, that it will make hole stability and well control problems.
    - The optimum circulation rates can be evaluated while moving the drill string inside the well bore.
- Provide an assessment of the needed “pressure window VS. Depth” with the provided drillstring and well configurations.
- Assessment of the need for Continuous Circulation System and MPD Systems, or just the well can be drilled Conventionally.
- Applicability of a Sensitivity Analysis for any of the variables.

Assumptions for the Hydraulic Simulator:

- Vertical Wellbore (Only for Drill string Acceleration Calculations), but for any other calculations the measured depths will be valid to be used in non-vertical wells.
- No Mud Compressibility
  Which is a valid assumption in case of water base mud, and In case of oil base mud, the calculations will be more conservative.
- No Well Compressibility effect is included in the calculations.
- No effect of cuttings in the drilling fluid in the annulus.
  That the rheology and density is the original of the mud, and it does not have any change by the effect of cuttings.
- Flat Mud Rheology (Effects of Pressure and temperature are unconsidered).
- Concentric drill string in the wellbore (A conservative assumption for annular pressure loss calculations)
- Steady State mud flow conditions.
- No hole washing/swelling is considered in open hole section.

Rheological Module

Background:

All of the hydraulic calculations which will be needed for the evaluation of the pressure inside the wellbore, will need an accurate modeling of the fluid rheology. Especially, when dealing with more pressure sensitive techniques like MPD applications and studies.

The first and most important step in any hydraulic simulator is the creation of the drilling fluid rheological model. The main objective of this module is building the rheological model that will be utilized in the hydraulic calculations in further steps and modules of hydraulic simulation.

The Rheological Models utilized in the study are the three rheological models that are mentioned in the API Recommended practice (API RP 13D) for non-Newtonian fluids:

- Bingham Plastic fluid Model.
- Power Law fluid model.
- Herschel-Bulkley (Modified Power Law) Model.

Newtonian Fluid Model:
The fluid to be defined as Newtonian, when the viscosity of the fluid is independent on the shear rate. Newtonian Fluids can be described by a single coefficient only, which is viscosity(μ).

$$\text{Shear Stress, } (\tau) = \text{Viscosity } (\mu) * \text{Shear Rate, } (\gamma)$$

Most of drilling fluids are not behaving as a newtonian fluid, so the need for more complex fluid model arised, rheological models where the viscosity of the fluid is dependent on the shear rate.

Bingham Plastic Fluid Model:
This model is represented as a straight line relationship between shear stress and shear rate in the Cartesian plane, but the start point will not be from the zero as Newtonian fluids. Bingham Fluid models will start from a point in the shear stress axis call yield point (τ_y). Yield point is defined as the minimum stress that can be applied on the fluid to make it able to move. The slope of the line for Bingham Fluid Models is called Plastic Viscosity (PV).
It's a two parameters model, Yield Point, and Plastic Viscosity. Represented by the following relationship.

$$\boldsymbol{\tau = \tau_y + K.\gamma} \text{ Or } \boldsymbol{\tau = \mathbf{YP} + PV.\gamma}$$

Practically, and with respect to API RP 13D, The Values of YP and PV are determined from high shear rates of 511 s-1 and 1022 s-1. So, this model is characterized to have a good match in high shear rates, but an over estimation of shear stress at low shear rates (Which will lead to an over estimation of pressure drop calculations).

Power Law Fluid Model (Pseudo plastic Fluid Model):
Power law model is modeling the behavior of shear thinning fluids. Shear thinning fluids means they will have a lower apparent viscosity at higher shear rates. It gives a straight line relationship between shear rate and shear stress on the log-log plane.
It's a two parameters model; Flow Behavior Index (n), and consistency index (k). Represented by the following equation:

$$\boldsymbol{\tau = K.\gamma^n}$$

Newtonian fluid can be a special case for this model, when n = 1.
Although, shear thickening fluids are extremely rare to be encountered, but this model can be used to model dilatant fluids or shear thickening fluids (by setting n>1).
Until the release of API RP 13D – 2010, This was the recommended model for simulating fluid behavior in the wellbore.
This model is very useful and proven to be accurate in simulating fluid rheology, but it might lead to substantial errors while simulating the fluids that does have Yield Point.

Herschel Bulkley Fluid Model(Yield-Pseudoplastic Fluid Model):
As it is the same form of the power law model but adding the yield point term to it, It is also called modified power law model.
It's a three parameter model, Flow Behavior Index (n),and consistency index (k)and yield point (τ_y). Represented by the following equation:

$$\boldsymbol{\tau = \tau_y + K.\gamma^n}$$

Herschel – Bulkley Model is the recommended model by API RP 13D-2010 to be utilized to simulate the fluid rheology in the wellbore. It had been even mentioned by "de Facto" rheological model for advanced engineering calculations.

Herschel – Bulkley is the recommended model as:

- It can simulate the fluid rheology at different shear rates with a great match with the non-Newtonian fluid behavior.
- Most of the drilling fluid are described well with it.
- It is the most generalized fluid behavior model, that it can simulate other models as a special cases.(e.g., For Bingham Plastic(n=1) , For power law model($\tau_y = 0$)).

Table.7 provides a summary of different fluid models and their there parameters:

TABLE 7: RHEOLOGICAL MODELS

Fluid Model	Yield Point, τ_y	K	n	equation
Newtonian	0	Viscosity (μ)	1	$\tau = K.\gamma$
Bingham Plastic	τ_y	Plastic Viscosity (PV)	1	$\tau = \tau_y + K.\gamma$
Power-Law	0	K	n	$\tau = K.\gamma^n$
Herscel-Bulkley	τ_y	K	n	$\tau = \tau_y + K.\gamma^n$

The modules Operation:

As mentioned before, one key aspect in the correct simulation of the rheological model is the correct selection of the rheological model that able to regenerate the measured data with the least error.

The rheological module gives the user the flexibility to use the model that matches the best the input measured data. Moreover, gives a recommendation for the models to be used, based on the error calculations and deviation from real data.

The workflow of the rheological module is shown **figure.35**, and described as following:

1- Starting from the entering lab data of the 6 rotor speeds vs. Dial readings (Concentric –Cylinder "Couette" Viscometer); the system calculates the model parameters (n, τ_y, K), which are required to simulate mud rheology. Parameters are then calculated for different non-Newtonian fluid models, and with different techniques.
(The procedures of calculation of model parameters are cited in details in Appendix A).
   a. Bingham Plastic Model Parameters (n=1, τ_y, K),
      i. API RP 13D
      ii. Best Fit
   b. Power Law Model(n, $\tau_y = 0$, K),
      i. API RP 13D
      ii. Best Fit
   c. Herschel Bulkley Model(n, τ_y, K),
      i. API RP 13D
      ii. Golden Section Search

2- After calculating all model parameters, the models are used to recalculate the lab data again (i.e., calculate shear stresses at the same lab shear rates) to assess the accuracy of each of them.

3- The module will represent the accuracy of each of these models with their parameters, in a summary table with the values of the relevant "R-Squared" for each of them.
   - **Over All:** the accuracy of the model overall shear ranges.
      o The highest to be recommended as an overall shear ranges model to describe the fluid rheology.
   - **Low Shear Rates:** The accuracy of the model at low shear rates (Rotor speeds 3, 6, 100 rpm)
      o The highest to be recommended for Annular or Laminar flow.
   - **High Shear Rates:** The accuracy of the model at high shear rates (Rotor speeds 600, 300, 200 rpm)
      o The highest to be recommended for Drill string or Turbulent flow.

Then, The module will give the recommended model to be used in the hydraulic calculations, based on the highest "R-Squared".

Several studies had concluded that one single fluid model might not be adequate to simulate the fluid rheology at all shear rates at all conditions. Thus, the fluid can act as Bingham fluid inside the drill string but matches the behavior of Power law fluid in the annulus.
Moreover, it can be shown by that at API RP 13D the parameters for the power law model are different from the flow inside the drill sting (calculated based on high shear rates speeds 600 and 300 rpm), to the annular flow(calculated based on low shear rates speeds 100 and 3 rpm).

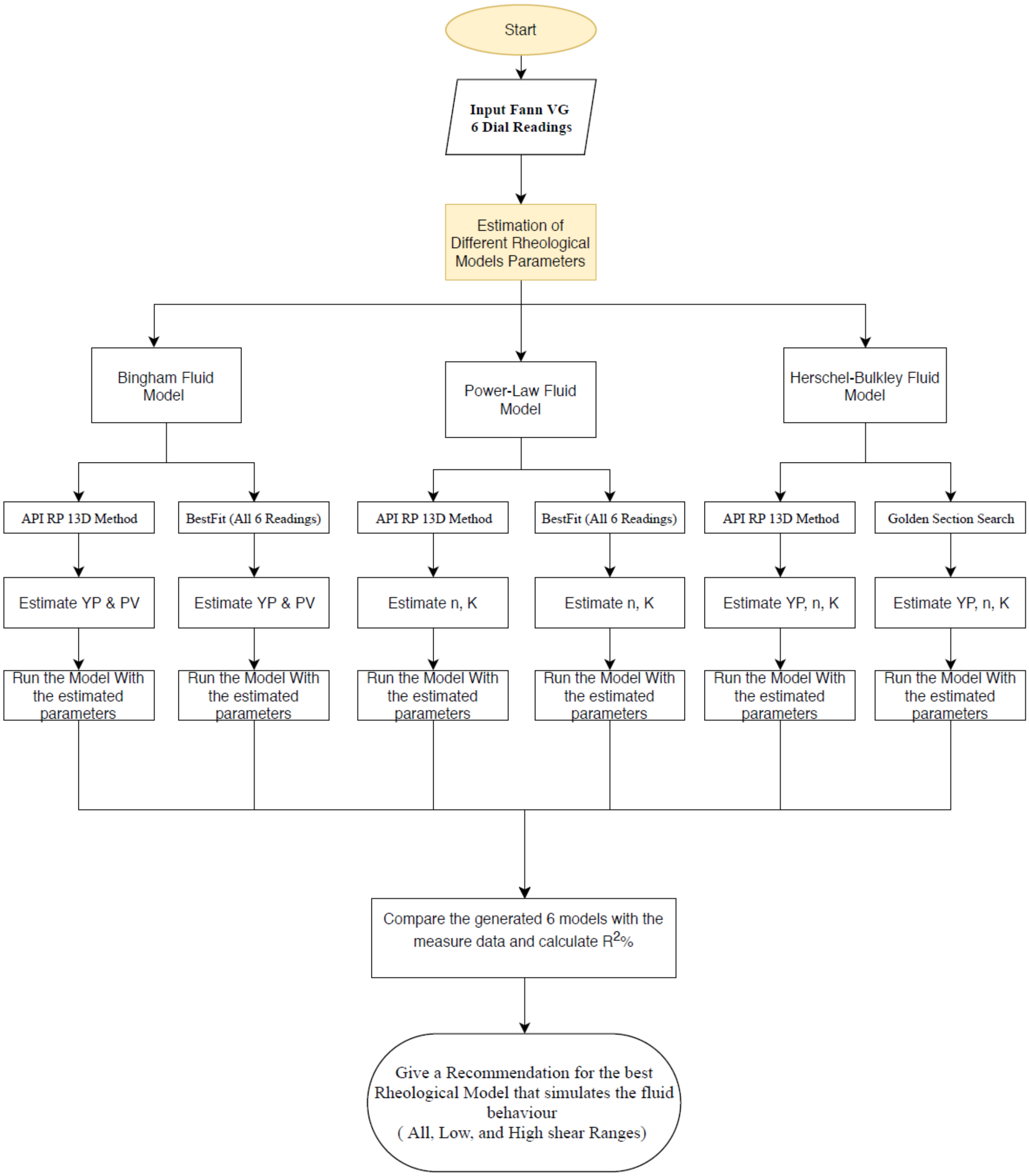


FIGURE 35: DASS RHEOLOGICAL MODULE WORKFLOW CHART

The following **figure.36** is a screen shot of the interface of the rheological module. Which starts by entering the laboratory test data.

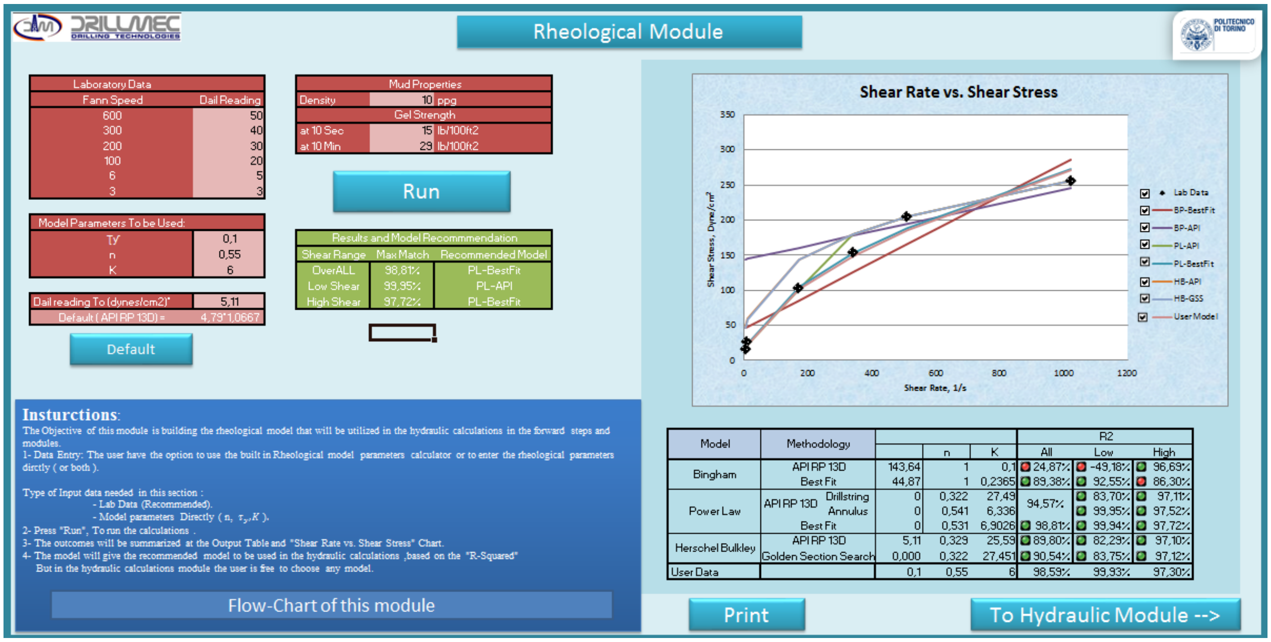


FIGURE 36: DASS RHEOLOGICAL MODULE SCREENSHOT

The output of the Rheology module can be concluded on the following:

1- Chart of Shear rates vs. Shear Stress, .
2- Models Parameters for different rheological models studied, with the accuracy of each model, **figure.37** is an example of the match analysis table.
3- The recommended models.

Model	Methodology	Dyne/cm2 Ty	n	Dyne.s^n/cm2 K	R2 All	R2 Low	R2 High
Bingham	API RP 13D	95,760518	1	0,2	76,72%	48,67%	99,46%
	Best Fit	32,46	1	0,2901	95,53%	95,30%	95,73%
Power Law	API RP 13D Drillstring	0	0,585	5,34	99,39%	99,76%	99,82%
	API RP 13D Annulus	0	0,657	3,497119458		100,00%	97,97%
	Best Fit	0	0,650	3,49112279	99,84%	99,95%	99,75%
Herschel Bulkley	API RP 13D	5,11	0,597	4,82	99,62%	99,38%	99,81%
	Golden Section Search	0,000	0,585	5,323	99,80%	99,76%	99,83%
User Data							

FIGURE 37: EXAMPLE OF DASS OUTPUT FOR MODEL PARAMETERS AND ACCURACY CALCULATIONS

Hydraulic Calculations Module For MPD Applications

Background:

MPD applications are based on controlling and manipulating the pressures and pressure profiles in the well bore.

That will need a simulation of the factors that can cause pressure surges downhole, and a study of the downhole pressures at all possible situations in the drilling process:

1- Drilling.
2- Tripping.
3- Making a Connection.
4- Well control and shutdown operations.

The general downhole pressure expression can be written as:

$$BHP = P_h + P_a + P_{SS} + P_{GS} + P_{acc} + P_{Cl}$$

- P_h, Hydrostatic Mud pressure.
  The permanent term in the bottom hole pressure expression, the static mud density.
- P_a, Annular Friction pressure losses.
  Exist when there is circulation of mud in the wellbore.
- P_{SS}, Surge and swab pressures (Due to Piston Effect).
  Exist When There is drill string movement inside the well bore.
- P_{GS}, Gel Strength breaking surge pressure;
  Due to the Thixotropic behavior of the drilling fluid.Exist when the well circulation is starting after being static for a period of time.
- P_{acc}, Drill string inertial surge pressures .
  Exist when there is acceleration or deceleration of the drill string inside the wellbore.
- P_{Cl}, Surface Choke line back Pressure.
  Exist when the operation is pressure controlled from the surface by a choke line (e.g., Well Control operation, MPD Choke manifold...etc.)

The calculation of each of these terms is explained in appendix “A” relevant to “API RP 13D”

These terms to be defined and quantified depending on the well operation.

For Example:

- Static Well (conventional) → $BHP = P_h$
- Static Well (MPD) → $BHP = P_h + P_{Cl}$
- Dynamic Circulating well → $BHP = P_h + P_a$
- Dynamic Circulating well with pipe line acceleration and movement
  → $BHP = P_h + P_a + P_{SS} + P_{acc}$

Module Operation:

Module objective is to make the hydraulic calculations, and to report and calculate the minimum mud pressure window required at each depth.
This module is concerned with the quantification of the pressure losses and pressure surges that exist in the wellbore in different situations (Utilizing Continuous Circulation System or not).

Module actions is explained in the following steps, and **figure.38** provides a screenshot of the module :

1- The Definition of wellbore and drill string geometry.

2- Calculation of the pressure losses in the annulus as we run the drill string in hole from the surface to the total depth.
The RIH process is divided in a predefined steps (based on the needed resolution), and with each step all the hydraulic calculations will run:
   - Annular Pressure Losses.
   - Annular Pressure Losses + Surge pressures while pump is on.
   - Surge Pressure While the pump is off.
   - Gel Strength breaking pressure.

3- The output from the hydraulic module: will be the minimum pressure window needed in two cases:
   a. Conventional Drilling Approach
   b. Open Loop CCS Approach

   The exact calculation of the minimum pressure window in these both cases is described later in the next section of

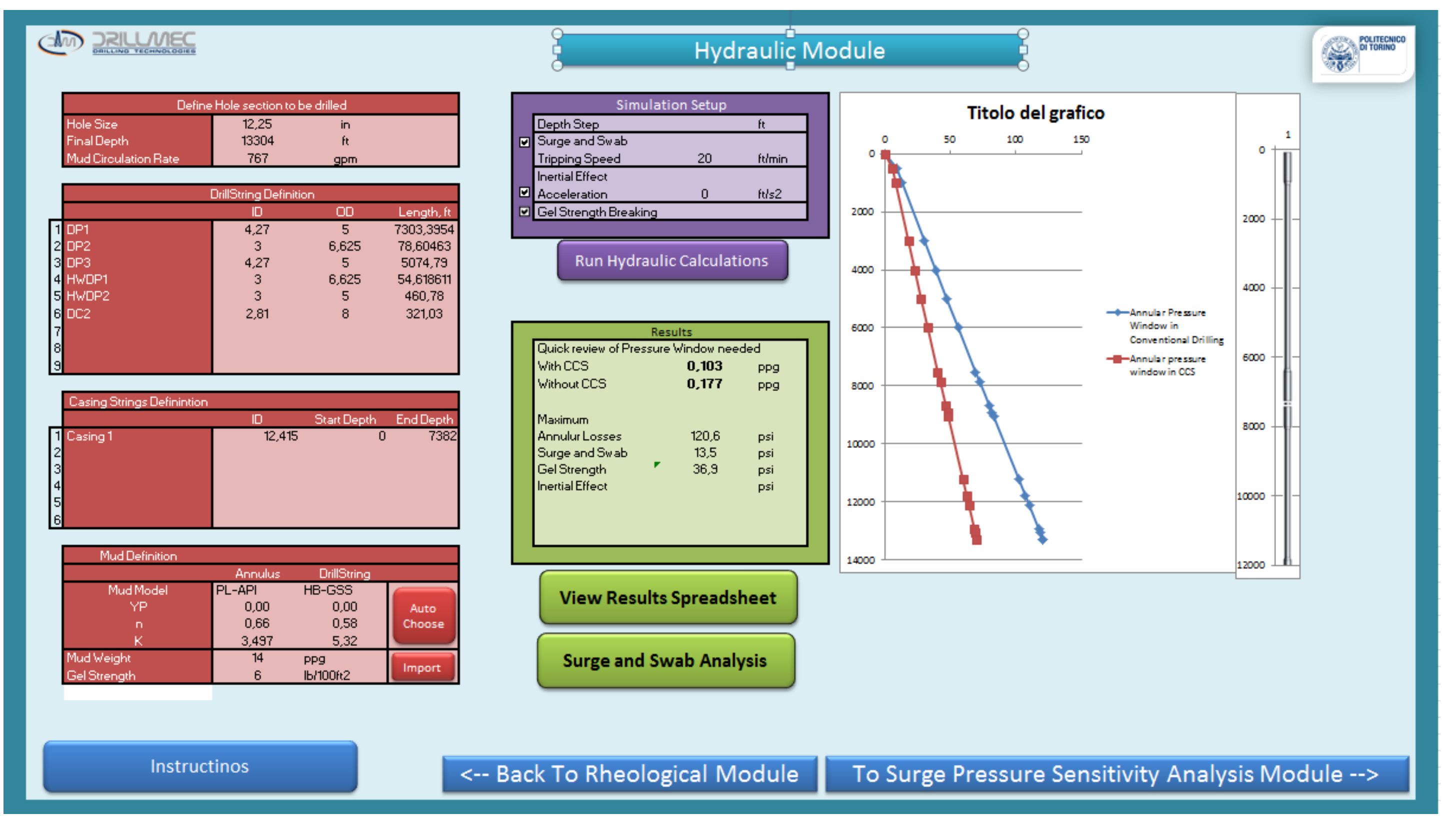


FIGURE 38: DASS HYDRAULIC MODULE SCREENSHOT

Surge/Swab Sensitivity Analysis Module

Background

Surge and swab sensitivity analysis calculations are useful in:

1- The selection of the optimum circulating rate in tripping conditions, in order to reduce the surge pressures due to pipe movement.
2- Knowing the movement speed limits, and how the pressure would change vs. drill string velocity.
3- Quantification of the effect of surge and swab while having circulation in the well.

The utilization of CCS while tripping in/out of hole is proved useful in the reduction of surge pressure effects downhole.

Figure.39 is created for a hypothetical well model in order to view the different regions found in Surge pressures can be divided to four parts:

- The Zero circulation Rate represents the conventional drilling, without CCS

The three following regions consider the utilization of CCS system,

- Surge pressures found to be decreasing by increasing the fluid circulation rate.
- The Plateau region, Where the pressure at its minimum
- The Turbulent Flow Region, Where the surge pressure will be higher than its initial value at zero rate. That having circulation in the well will add a negative effect in the surge pressures.

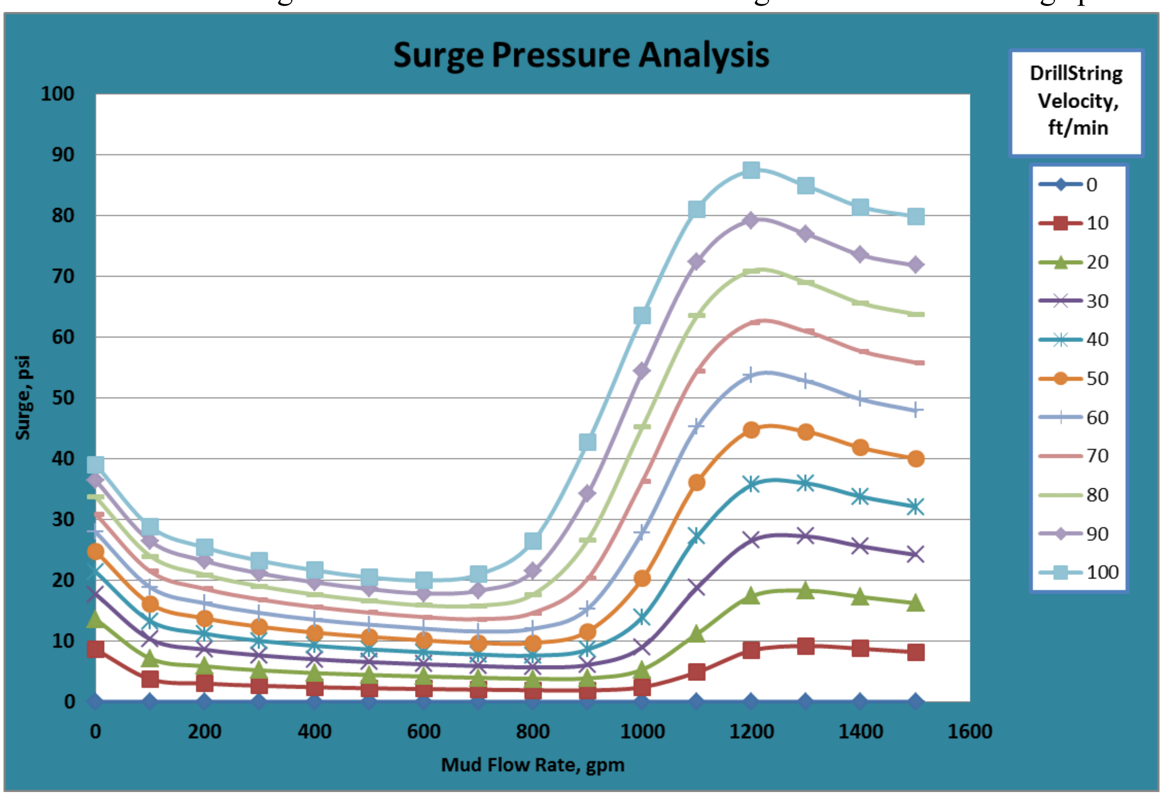


FIGURE 39: SURGE PRESSURE SENSITIVITY ANALYSIS WITH RATE AND DRILLSTRING VELOCITY

Module Operation

This module is the third step after utilizing all of the previous two modules:

- Rheological Module → To define the mud rheology.
- Hydraulic Calculations Module → To define the drill string and well geometry.

The module operation is explained on the following few steps:

1- Input the range of mud circulation rates, along with the required number of steps.
2- Input the range of drill string movement velocities, along with the required number of steps.
3- Run the module. (Which calculate the surge pressures for each pair of Mud circulation rate and drill string velocity)
4- The output of calculations will be shown in a form of chart of Surge pressure vs. circulation rate for various drill string movement velocities.

An screenshot of the Module is shown in the following **figure.40**

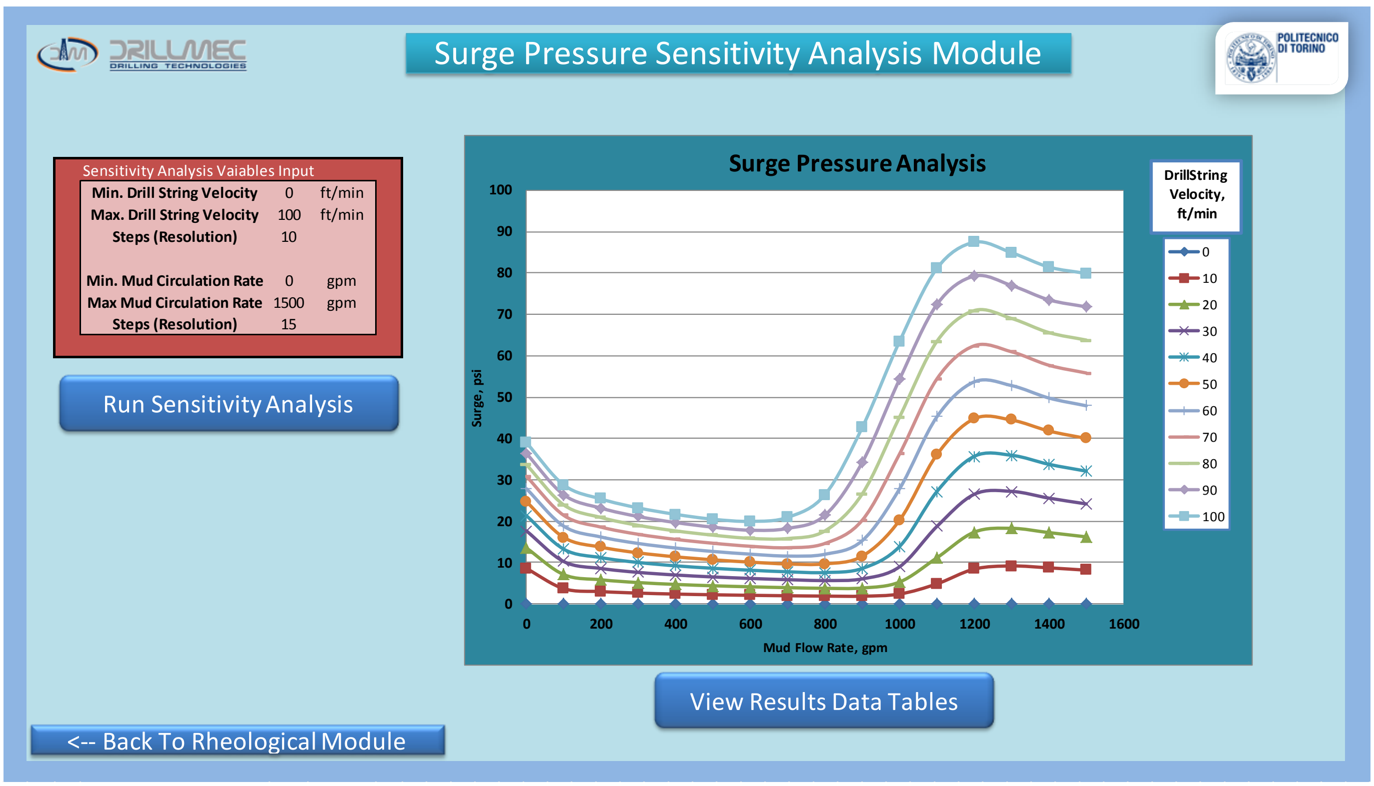


FIGURE 40: SWAB PRESSURE SENSITIVITY ANALYSIS MODULE SCREENSHOT

Chapter 5: DASS - Results and Discussion

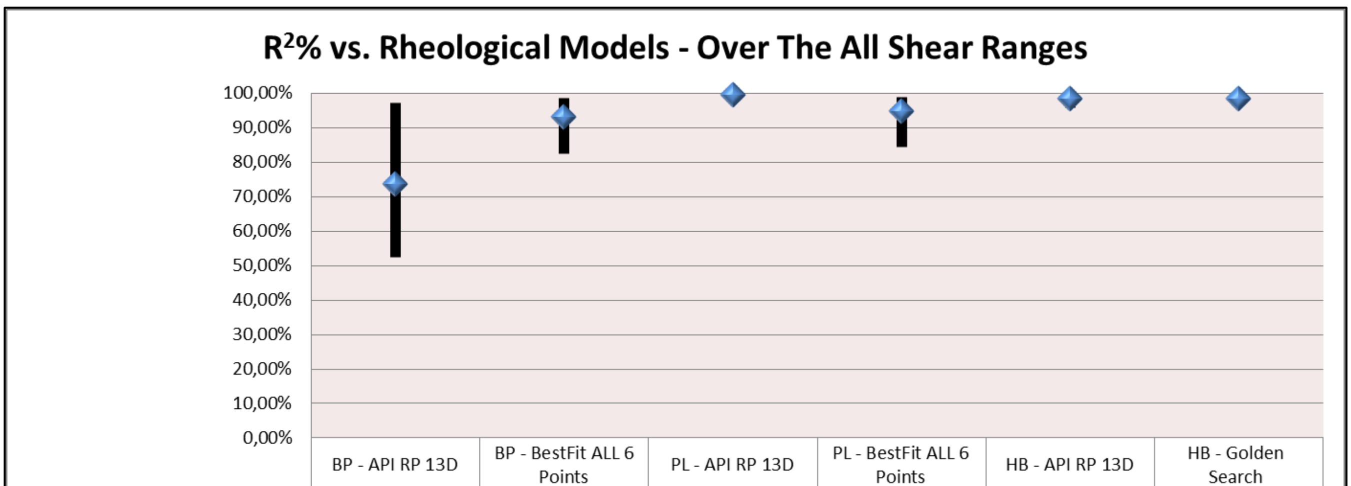
This chapter will discuss DASS Software, and Workflow application in real data. Discussing the outcomes and benefits of DASS Process.

Rheological Model Selection

Lab data for 11 mud samples had been utilized and used in the rheological module in order to study the accuracy of the match of the several rheological models in the software. The objective of the study is to discover the optimum model and the one to be recommended in MPD operations.

The following three charts represent the match between the lab data and the created models in terms of R2%, at

- Overall Shear Rates, **Figure.40**.
- Low Shear Rates, **Figure.41**.
- High Shear Rates, **Figure.42**.



	BP - API RP 13D	BP - BestFit ALL 6 Points	PL - API RP 13D	PL - BestFit ALL 6 Points	HB - API RP 13D	HB - Golden Search
Minimum Match Experienced	52,55%	82,43%	97,93%	84,49%	96,00%	96,32%
Maximum Match Experienced	97,21%	98,73%	99,95%	98,87%	99,85%	99,96%
Median	73,66%	92,95%	99,54%	94,76%	98,32%	98,48%

FIGURE 40: RHEOLOGICAL MODEL MATCH, ALL SHEAR RATES

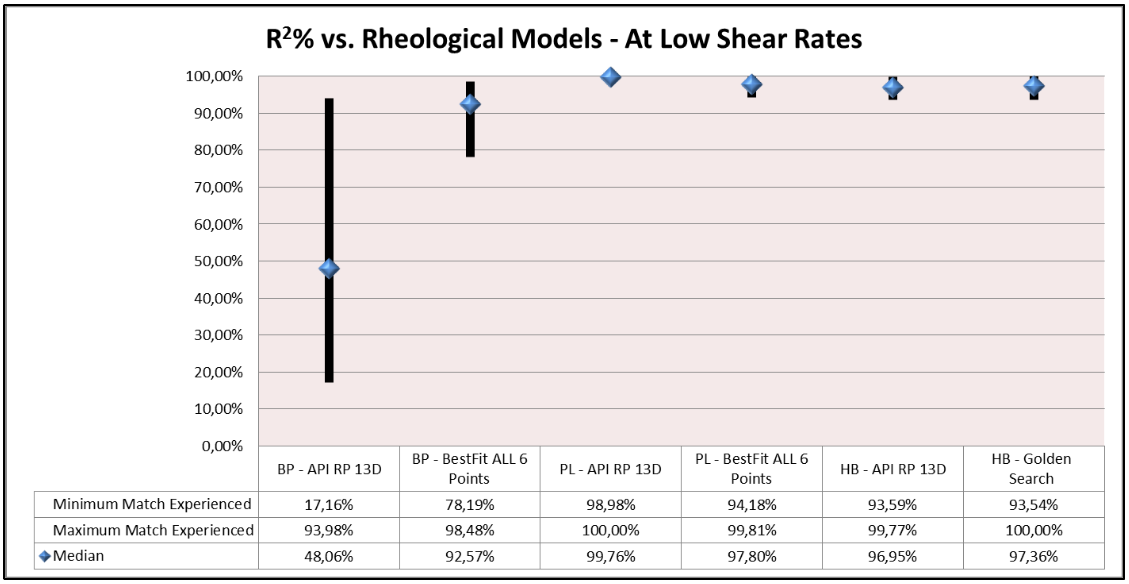


FIGURE 41: RHEOLOGICAL MODEL MATCH, LOW SHEAR RATES

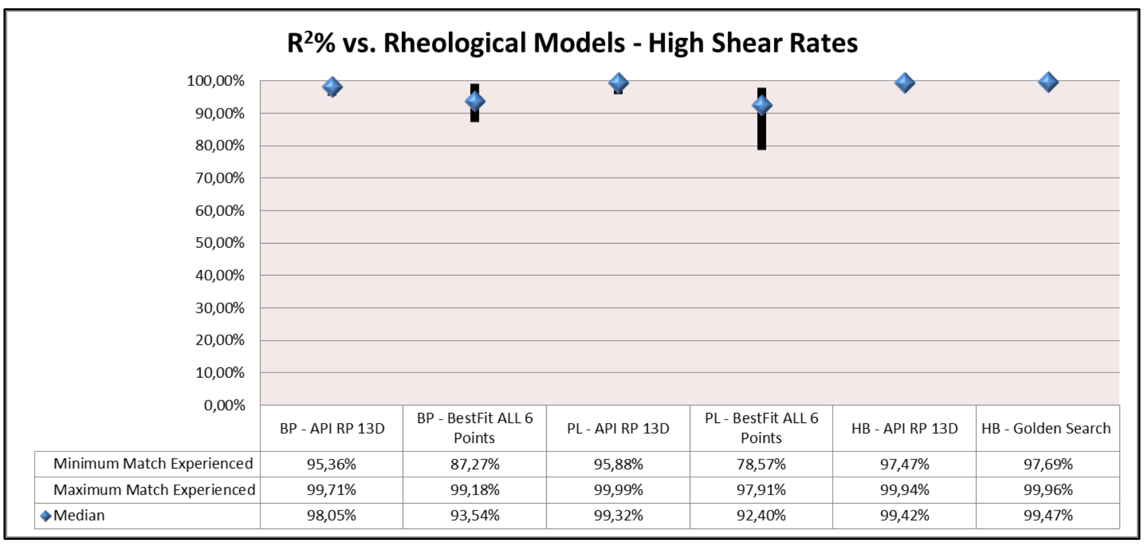


FIGURE 42: RHEOLOGICAL MODEL MATCH, HIGH SHEAR RATES

The findings are:

- There is no one unique model that can describe the rheological behavior in all shear ranges:
  - **At low shear rates** the best model that describe the rheological behavior is PowerLaw Model.
  - **At high shear rates** the best model that describe the rheological behavior is Herschel-Bulkley Model, with Golden Search Method.
  - **At all shear rates** the best model that describes the rheological behavior is PL Model, With API Recommended Practices Method, because it uses two different set of parameters, one for high shear rates, and one for low shear rates.
    If it had been disregarded as a general model, the best Model to describe the fluid behavior at all shear rates will be Herschel-Bulkley Model, with Golden Search Method.

DASS Workflow application in Darquain Field

This section present an example on the utilization of DASS workflow in the decision making process for drilling in a tight pressure conditions.
The well and field data had been taken from a feasibility study for CBHP MPD application in Darquain field. The study is Published, by Nakhost A.T. and Shadizade S.R., in 2013 in Journal of Petroleum Science and technology. In that study all hydraulic calculation had been accomplished by DZxION (Nauduri, 2009), a software developed for the data analysis for MPD screening process.

The original study concluded that:

1- utilization of conventional drilling technique will not viable because of the tight pressure conditions that will impose losses in the well bore.
2- The use of near balanced drilling fluid will be viable in conventional conditions only by reducing the circulation rate to a value that might induce hole problems due to cuttings loading.
3- the use of underbalanced drilling fluid with closed loop MPD (Without Continuous Circulation System) will be the best feasible solution for the well conditions.

The same data will be re-evaluated again with the developed DASS software and workflow for the assessment of CBHP MPD application..

Well and Field Data

The presented well and field conditions are from Iranian Darquain Oil Field. In 2001 National Iranian Oil Company (NIOC) Contracted with Eni and Naftiran Intertrade Company (NICO) the agreement for the development of the onshore oil field Darquain in the Iranian province of Kuzestan.

This study is aiming to find the most optimum drilling approach to drill the next well in the field DQ#5. The target reservoir is the carbonate sequence Fahilyan Formation in lower Cretaceous Khami group. The primary sources for the pressure and offset data are Exploration well DQ#2 and Appraisal well DQ#4.
The main challenges found in drilling in this zone to reach the target are:

- Tight Pressure Window. Due to the expected high pressure of the reservoir section, and low fracture pressure in .
- Sour fluids presence in the some zones.

The full well data set of pressure profiles, and drilling parameters are mentioned in appendix “C”.
The casing design in that well is provided in **table.8**:

TABLE 8: DARQUAIN FILED, WELL CASING DATA, (NAKHOST A.T. AND SHADIZADEH S.R., 2013).

Description	Hole Diameter	Casing OD	Casing ID	Start Depth	End Depth
Conductor	24	18.625	17.755	0	820.25
Surface Casing	17.5	13.375	12.415	0	7382.25
Open hole	12.25	9.625	8.535	7382.25	13304.45

The section which had experienced significant losses and drilling problems is the open hole section from the depth of 7382ft to 133304ft. Thus, the drilling of the 12.25” hole will have to focus for MPD system application.

Results of DASS Application :

1- Rheological Study:

The drilling mud FANN viscosity data are used to create the hydraulic model of the mud using the hydraulic module of DASS software. **Table.9** provide the match results for each model.

TABLE 9:RHEOLOGICAL MODEL STUDY - DARQUAIN OIL FIELD DQ#5

Model	Methodology		Dyne/cm2		Dyne.s^n/cm2	R2		
			Ty	n	K	All	Low	High
Bingham	API RP 13D		95,760518	1	0,2	76,72%	48,67%	99,46%
	Best Fit		32,46	1	0,2901	95,53%	95,30%	95,73%
Power Law	API RP 13D	Drillstring	0	0,585	5,34	99,39%	99,76%	99,82%
		Annulus	0	0,657	3,497119458		100,00%	97,97%
	Best Fit		0	0,650	3,49112279	99,84%	99,95%	99,75%
Herschel Bulkley	API RP 13D		5,11	0,597	4,82	99,62%	99,38%	99,81%
	Golden Section Search		0,000	0,585	5,323	99,80%	99,76%	99,83%

Based on the rheological study, three Rheological models will be used for the sensitivity analysis and simulation of the drilling fluid.

1- Power Law – API RP 13D
   It provides the best fit in the annular low shear rate conditions
2- Power Law – Best Fit (For all 6 Dial Readings)
   It provides the best fit for the rheological data in the all shear rates.
3- Herschel Bulkley – API RP 13D
   The latest recommended practice from API RP 13D

2- Hydraulic Study

The data of wellbore and drilling geometry are used along with power law mud rheological model are used as in input in the hydraulic calculations module in DASS software, to calculate friction pressure losses and possible pressure fluctuations while drilling 12.25" hole section.
Sensitivity analysis is done for different mud weights with the three chosen rheological models.
The following **table.10** is reporting sensitivity analysis results and the required pressure window between formation pressure and fracture pressure in case of conventional drilling, and in case of CCS deployment.

TABLE 10: PRESSURE WINDOW REQUIRED, OUTPUT FROM DASS SOFTWARE

Mud Weight / **Model**		**Mud window required, ppg** (Analysis done for mud weights From 14.43 to 14.63 ppg)
Power Law- API RP 13D	Conventional	0.177
	CCS	0.103
Power Law Best Fit	Conventional	0.174
	CCS	0.100
Herschel Bulkley API RP 13D	Conventional	0.217
	CCS	0.125

The effect of changing the mud weight have a negligible effect on the pressure losses in the annulus, that the needed window in each of the mud weights starting from 14.43 to 14.63 ppg stays the same and constant up to the third decimal (in terms of ppg).
The effect of changing the rheological model, can affect the pressure window requirements dramatically, That HB model require a mud window which is higher than that needed with PL model by around 25%.

3- Data Analysis and decision making

- The evaluation of the Available pressure window in the open hole section:
  The Pressure window in the open hole 12.25" section is the difference between the lowest fracture pressure at Sarvak formation and the highest reservoir pressure at the beginning of the reservoir section. The drilling margin is found to be 0.11 ppg, **table.11**.

TABLE 11: PRESSURE WINDOW IN DARQUAIN OIL FIELD - DQ#5

Maximum Pore Pressure, ppg	Minimum Fracture Gradient, ppg	Drilling Window, ppg
14.43	**14.54**	**0.11**

- By the comparison of the acquired data from the hydraulic module and following DASS workflow the following **table.12** summarize and elaborate the decision for each of the drilling approaches.

TABLE 12: DASS WORKFLOW APPLICATION FOR DARQUAIN OIL FIELD – DQ#5

Conventional Drilling Approach **Status: Declined**
The pressure window required is ranging from 0.174 to 0.217 ppg, depending on the rheological model to be used. But in all cases, The needed pressure window is higher than 0.11 ppg. Thus, by the conventional drilling, the well control, and drilling problems will not be avoidable, and put individuals, environment and assets into risk. Thus, the conventional drilling approach is declined.
Open Loop CCS **Status : Acceptable but critical**
The utilization of continuous circulation system is reducing the pressure window needed down to 60% of that needed in conventional drilling. The Pressure window required is ranging from 0.103 to 0.125 ppg, depending on the rheological model to be used. Theoretically, the well can be drilled by the utilization of CCS; as the required pressure window is 0.103 ppg. which is lower than the available window 0.11 ppg. The static and dynamic pressure gradient with CCS is shown in **figure.43.**

Practically, the system will be risky to be applied, because of several factors:

- By changing the rheological model to Herschel Bulkley model, the situation will not be controllable and CCS is declined to be applied.
- The Margin between the drilling window and the required window is extremely narrow 0.07 ppg (i.e., Allows us to make a margin from formation pressure and fracture pressure by around 20 psi only). Which means the probability of having kick or losses is high. For example, the effect of cuttings load itself can induce losses in the well.

If it was decide to use the CCS approach for drilling, the following points are recommended:

- The usage of another type of mud with lower yield properties.
  Taking into consideration, that might affect the cutting carrying ability of the mud.
- The usage of lower circulation rates in order to reduce annular frictional pressure losses. Thus, the required window will be smaller and the margin to be larger.
  Taking into consideration, that will affect the whole cleaning and cuttings removal speed from the wellbore.
- Real Time monitoring and Strict control on the operation and the installation of EKLD system.

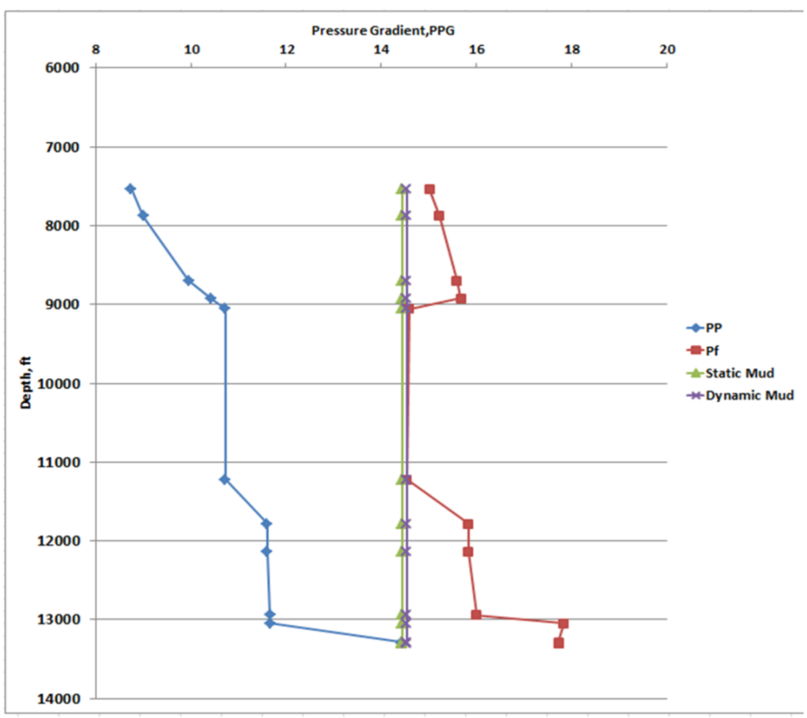


FIGURE 43: GRADIENT PROFILE WITH CCS UTILIZATION

Closed loop and Continuous Circulation system (CCS + RCD) Status : Acceptable
The best solution is to drill the well with an underbalanced drilling fluid in a closed loop configuration. That to have the dynamic condition the ECD is above P_p and lower than P_f. In the static condition, pressure to be applied from the surface to keep the well overbalanced. The recommended ECD in the well bore is to be lower than 14.48 ppg in order to make sure of not having losses in the Sarvak formation. Thus , the recommended mud weight to be utilized in the drilling process to be lower than 14.37 ppg with 0.11 ppg back pressure application in the static conditions of the well.

- **The final decision is that; any of the CBHP MPD systems is able to control the situation and to be able to drill the well from the theoretical point of view.**
- But due to the criticality of the situation of CCS in open loop configuration; the drilling approach is decided to be made safer by reducing the probability of well control issues and using underbalanced drilling fluid in a closed loop system configuration along with CCS.

4- **The Surge and swab Pressure sensitivity analysis**

Surge and swab sensitivity analysis module is used to optimize the tripping circulation rate when utilizing the CCS in order to know the optimum circulation rate while tripping in/out. The optimum conditions to reduce the piston and surge pressures downhole.

The Optimum speed of tripping in is a point of optimization by the operator, that as the tripping speed increase as the NPT decrease. In the other side, as tripping speed decrease as the piston effects on downhole pressure decrease.
The results of the sensitivity analysis for surge pressure is shown in the following **figure.43.**

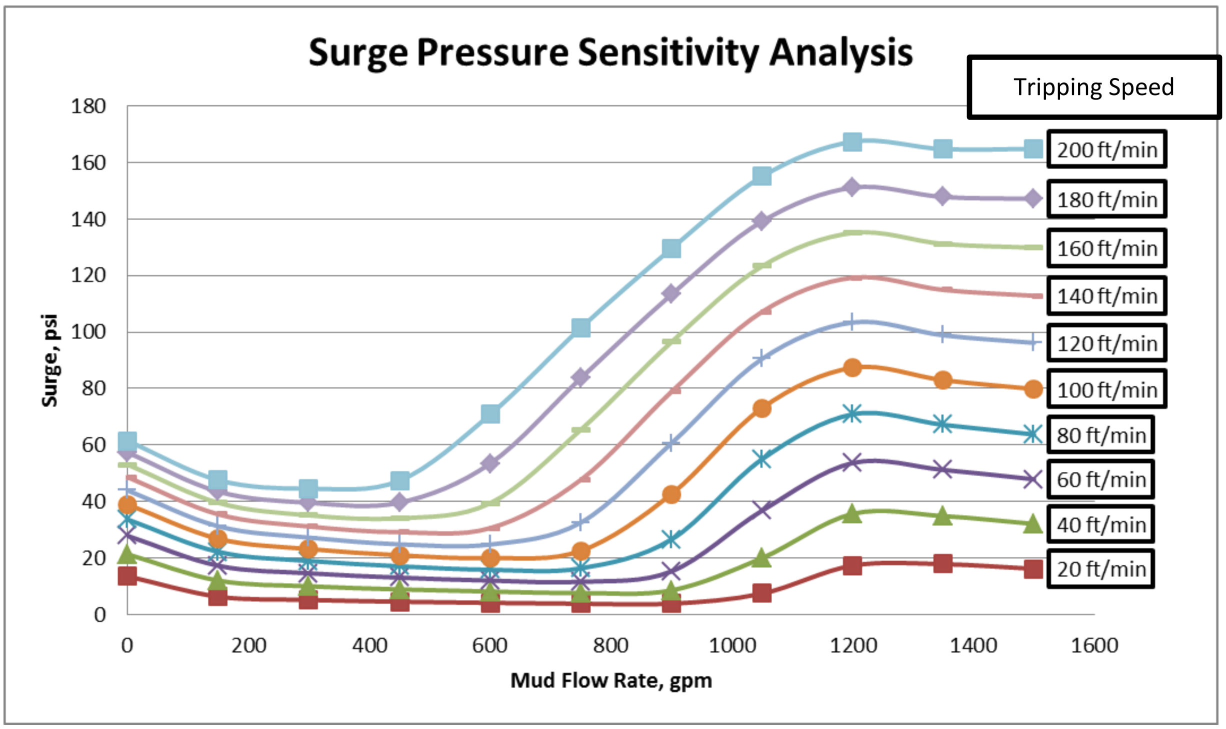


FIGURE 44: SURGE PRESSURE SENSITIVITY ANALYSIS, WELL DQ#5

Analysis of the results:
Results of simulations for well "DQ#5" at the tripping speed of 20 ft/min, shown in **table 13**:

TABLE 13: SURGE PRESSURE STUDY AT SPEED OF 20 FT/MIN, FOR WELL DQ#5

Parameter	Value
Surge Pressure with static wellbore	13.5 psi
Surge Pressure with circulation in the wellbore of 757 gpm	3.8 psi
The range of circulation rate for piston effect optimization and reduction	300 to 1000 gpm

Having circulation in the well reduced the surge pressure to 28% from its value with no circulation in the well.

- **Swab Pressure Sensitivity Analysis:**

A swab sensitivity analysis study had been made in order to optimize the tripping out process parameters of drill string speed and circulation rate. The swab pressures are shown in **Figure.45.**

Observations:

- There is a critical circulation rate for each of the drill string tripping out velocity.
  That critical circulation rate when the negative swab effect is equal to the positive effect of annular pressure losses. So that the resultant BHP at this conditions of rate and tripping out velocity is **equal to Zero.**
- Before that critical rate, the negative surge pressure is higher than annular friction losses, and it will cause the downhole pressure to be lower than equivalent static density of mud ESD.
- For circulation rates higher than the critical rate, the negative swab effect is lower than annular friction pressure losses, so the ECD will never fall below ESD.
- Consequently, it is important to define that critical circulation value to optimize the tripping out process. Assuring no kick will happen, by assuring that ECD will never be below formation pressure.
- For DQ#5 during drill string tripping speed of 20 ft/min, the critical circulation rate will be around 70 gpm.

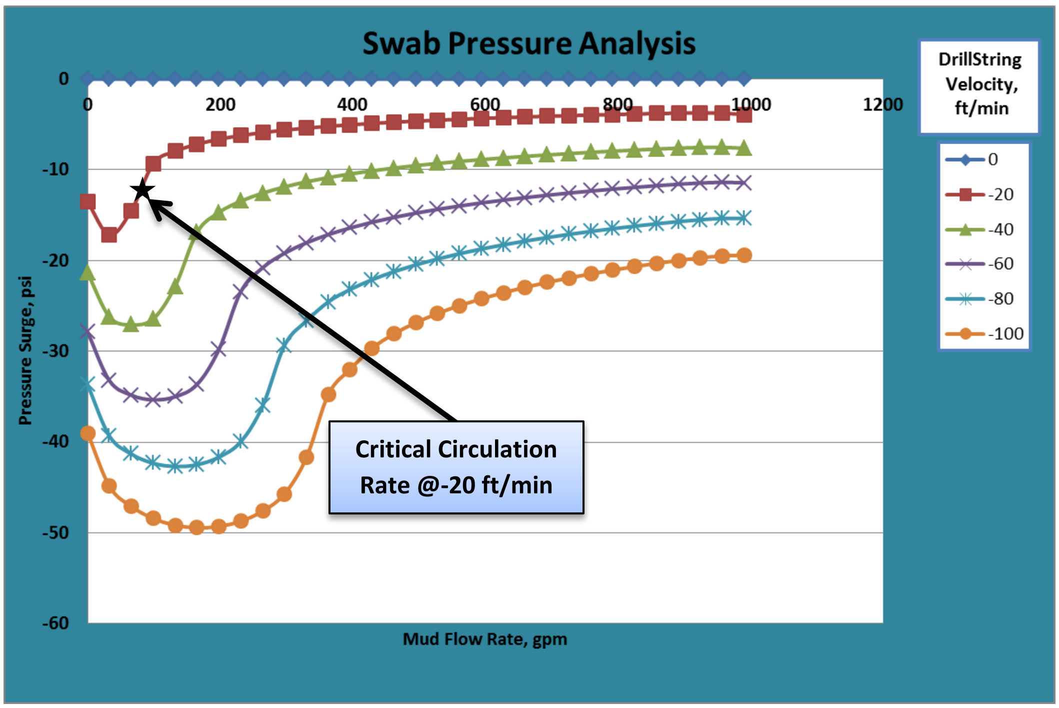


FIGURE 45: SWAB PRESSURE SENSITIVITY ANALYSIS FOR WELL DQ#5

Chapter 6: CONCLUSIONS

In the past few years, MPD Techniques and methodologies had proved its ability to overcome a lot of drilling issues and challenges which conventional drilling practices had not been able to solve it.

Each of one of MPD techniques is used to overcome specific problems. Nevertheless, the most widely used MPD method in onshore and offshore applications is Constant Bottom Hole Pressure CBHP technique. CBHP technique is concerned mainly by keeping the bottom hole pressure constant on the dynamic ECD value in all well operations, specially, while making a connection.

A focused review had been carried out with regard to CBHP MPD showing its ability to reduce the well control incidents by more than 75%. Reviewing the main enabling equipment of CBHP as the CCD (e.g., circulation Subs), and the RCD.
CBHP MPD technique can be done by one of two main methods:

- Continuous Circulation System CCS, which keeps the well in dynamic conditions while making/breaking a drill string connection.
- Annular Back Pressure Application, using RCD and MPD Choke Manifold.

By carrying out a comparison between the two main CBHP MPD techniques. The outcome can be concluded that the best package of CBHP MPD system would be by the utilization of a combination of both systems (i.e., the utilization of continuous circulation system in a closed loop fluid circulation system with MPD choke manifold).

Continuous circulation system would reduce the pressure surges inside the well, while the RCD and MPD Choke Manifold would help by applying back pressure from the annular side when circulation is lost for any reason. Moreover, to provide an additional mean of well control, maintaining the well primary barrier in case if the drilling fluid is underbalanced versus the formation pressure.

The application of MPD techniques can have its positive and/or negative impacts on the drilling operation.

Positive impacts would be as:

- Overcoming a lot of drilling problems.
- Lowering NPT
- Lowering the number of casing strings needed,
- Giving the ability to reach new depths.
- Increased well control level.

Negative Impacts:

- Rig modification and deviation from the conventional operation, which requires more expertise.
- Increased Complexity of the drilling system, which increases the vulnerability to HSE issues.
- Redefinition of Well Barriers.
- Most of MPD techniques are not fail safe, especially when an underbalanced drilling fluid is used with RCD.

In the well planning process, a thorough study of the well conditions is needed to give the right judgment regarding the utilization of MPD technique or not. Never the less, to decide the optimal MPD method that would give back the maximum benefit from safety and well cost aspects.

This research is focused in developing preliminary screening tool and evaluation scheme for the application of MPD CBHP Techniques in drilling. That would assess the well conditions and the planned drilling operation, to provide an awareness about the candidacy of the well for MPD.
The developed Scheme is Called DASS (Drilling Approach Selection Scheme).

Several attempts had been made to develop a quick MPD screening process qualitatively and quantitatively. DASS had been developed to take the screening process deeper in the CBHP method. By Comparing and assessing the two main CBHP main MPD techniques. Additionally , provides a robust conclusion about the well, and the best recommended approach to drill it safely to the target depth.

DASS is comprised of two interconnected parts:

1- **DASS Hydraulic Simulator,** is a visual basic based software. It is used to make all the needed hydraulic calculations for different operations that can happen in the well. All of the calculations are based on API Recommended practices.

DASS Hydraulic simulator is comprised of three main modules:

a. Rheological Module

Due to the sensitive behavior of MPD applications, the correct selection of the rheological model is a vital argument in the hydraulic calculations. The mission of the Rheological module is to help in the selection of the best rheological that simulate the drilling fluid in the drill string, and in the annular space.

b. Hydraulic Module

To make all the hydraulic calculations inside the wellbore, of pressure profile during circulation, Circulation breaking pressure, surge and swab pressures, drill string acceleration pressure surge….etc.
Furthermore, to calculate the minimum pressure window required for conventional drilling technique, and the minimum pressure window required for open loop continuous circulation system. Hydraulic Module quantifies the limits of conventional and CBHP MPD drilling approaches.

c. Surge Pressure sensitivity analysis module.

This module used to quantify the in the identification of possibilities of Surge and Swab pressure reduction and optimization, by:

- Defining the range of optimum circulation rate while tripping.
- Used to assess the BHA assembly geometry optimization with respect to surge pressures inside the wellbore.
- The effect of tripping speed on the surge pressure.

2- **DASS Workflow,** is a fit for purpose workflow that uses the Hydraulic calculations to reach a final answer about the recommended drilling approach.
The drilling approach will be chosen based on comparing the required pressure windows with the available pressure window between formation and fracture pressures.

The output from DASS process, will be the drilling technique that would assure the most safe conditions for personals and assets:

1. **No Need for MPD deployment,** The well can be drilled conventionally.
   When all the static and dynamic pressures inside the well (including the pressure surges and different well operations) fall between the formation pressure and fracture pressure.

2. **CBHP MPD is Mandatory,** CCS in Open loop Drilling fluid Configuration.
   When The static and dynamic pressures fall between the formation pressure and fracture pressure, but the pressure surges are expected to exceed the provided window.

3. **CBHP MPD is Mandatory,** CCS with Annular Back Pressure Application system (i.e., RCD and MPD Choke Manifold).
   When the difference between the dynamic and static pressures inside the well bore exceed the available window between the formation and fracture pressures. Thus, the need to use underbalanced drilling fluid will be mandatory.

DASS Process had been utilized to conduct the following studies:

1. Rheological study by DASS Software Rheological Module

Conducting a Hydraulic study on the three main mud fluid models (BP, PL, and HB) Aiming to find the best rheological model to simulate the Drilling fluid for MPD applications.
Proving that there is no single fluid model which is efficient enough to simulate all drilling fluid in all conditions in the wellbore, a special study must be made for each drilling fluid to find the best matching rheological model.

2. Case study of a well in Iranian Darquain Field:

Using the help of DASS software a study had been concluded to search for the best drilling approach for a drilling a well DQ#5, in Iranian Darquain Oil field.
The outcome from the DASS process can be concluded in that: The well cannot be drilled in the conventional way. The need for CBHP Managed Pressure Drilling techniques and methods is required. DASS process proved that the well can be drilled by Open Loop or Closed Loop Constant Bottom Hole Pressure MPD Technique.

Nevertheless, due to tight well conditions and extremely small margin while utilizing CCS alone, the recommended approach will be the combination of both systems (CCS + RCD and Choke Manifold) giving the ability of underbalanced drilling utilization to make the margin between the fracture pressure and the dynamic pressure high enough to avoid encountering losses while drilling.

Moreover, the DASS software surge pressure analysis module is used to provide a the optimum operation parameters to reduce the surge and swab pressures down hole.

Recommendations And Further Research

- The developed DASS workflow is mainly focused on MPD CBHP Technique, This Process might be developed to include all other MPD techniques, to be more general and collective method.
- In order to complete the remaining part of the feasibility study, the economic study part will play a big factor on the decision making process regarding MPD deployment.
- The Effect of Temperature and pressure on changing the mud rheology to be considered in the hydraulic calculations due to the sensitive condition of MPD systems application.
- Compressibility of Mud, Formation, Drill string, Casing Strings to be added into calculations. For example, can be achieved by utilizing and developing numerical simulators.

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APPENDIX A:Rheological and Hydraulic Calculations

The calculation of Rheological Model Parameters From Lab Data

The Lab Data are converted to scientific units by the following transformations:
Dial Reading to shear Stress:
Shear Stress ($lb_f/100ft^2$) = 1.066 * Dial Reading (θ)
Shear Stress ($Dyne/cm^2$) = 1.066 * 4.79 * Dial Reading
1.066 is a correction factor which depends on the lab procedures while making the test(R1-B1-F1 Configuration).

Viscometer Rotor Speed to Shear Rate:
Shear Rate (1/s) = 1.703 * Rotor Speed

Model Parameters Calculation:

A. Bingham Fluid Model:
    a. API RP 13D methodology:

Plastic Viscosity (PV), in cP $= \theta_{600} - \theta_{300}$

Yield Point (YP), in lbf/100ft2 $= \theta_{300} - PV$
$= 2\theta_{300} - \theta_{600}$

    b. Best Fit Methodology

Draw the straight line best fit for the lab data point in the Cartesian plot of shear rate vs. shear stress.
The slope of the straight line = PV
The intercept with Shear stress axis. = YP

B. Power Law Model:
    a. API RP 13D methodology:

API RP model had identified different parameters depending on the shear rates and flow medium.
For flow inside pipe line (High Shear Rates): n_p, and k_p

$$n_p = 3.32\, log_{10}\left(\frac{\theta_{600}}{\theta_{300}}\right)$$

$$k_p = \frac{\theta_{300}}{511^{n_p}}$$

For Flow inside the Annulus (Low Shear Rates): n_a, and k_a

$$n_a = 0.657\, log_{10}\left(\frac{\theta_{100}}{\theta_3}\right)$$

$$k_a = \frac{\theta_{100}}{170.3^{n_a}}$$

b. Best Fit Methodology:

Draw the straight line best fit for the lab data point in the Log-Log plot of shear rate vs. shear stress.

$\text{Log}(\tau) = \text{Log}(K) + n\log(\gamma)$

The Slope of the straight line = n

The intercept of the line at shear stress axis = log (k)

C. Herschel Bulkley Model:

a. API RP 13D methodology:

Yield Point (τ_y) ,

$\tau_y = 2\theta_3 - \theta_6$

Flow Index (n),

$$n = 3.32\ log_{10}\left(\frac{\theta_{600} - \tau_y}{\theta_{300} - \tau_y}\right)$$

Consistency Index (k),

$$k = \frac{\theta_{300} - \tau_y}{511^n}$$

b. Golden Section Search (GSS)

Non linear regression and numerical techniques can lead sometimes to negative values of the yield stress. So in this research the Golden section search analytical Iterative technique.

The yield point is calculated by the golden section search methodology, but the consistency index and flow index are calculated by the linear regression.

The golden section search process:

1- Define the range that we can search in it for the Yield Stress value.

Set the upper and lower limits of the Yield Stress, (U & L):

For Example: L = 0 , U = 2 . τ_{y0}

τ_{y0} is the Yield point which is calculated by the API Method, used to predict the range that the real yield point will lie in.

2- Calculate yield stress values by the defined : τ_{y1} and τ_{y2},

$$\tau_{y1} = L + 0.618 * (U - L)$$
$$\tau_{y2} = U - 0.618 * (U - L)$$

3- Get the Value of k_1, n_1 & k_2, n_2 , by linear regression from the following relations

$$\boldsymbol{log(\tau - \tau_{y1}) = \mathrm{Log}(\ K1) + \mathrm{n1.Log}(\gamma)}$$
$$\boldsymbol{log(\tau - \tau_{y2}) = \mathrm{Log}(\ K2) + \mathrm{n2.Log}(\gamma)}$$

4- Regenerate the Calculate the shear stress at the different shear rates (i.e., Six lab rotor speeds shear rates), by the acquired parameters from the previous step

$$\boldsymbol{\tau_1 = \tau_{y1} + k_1.\gamma^{n1}}$$
$$\boldsymbol{\tau_2 = \tau_{y2} + k_2.\gamma^{n2}}$$

5- Calculate the squared residuals by the comparison with the lab data

SSR1 = $(\boldsymbol{\tau_{measured} - \tau_1})^2$

SSR2 = $(\boldsymbol{\tau_{measured} - \tau_2})^2$

6- Based on the calculated residueals redefine the upper(U) and lower(L) limits of yield stress

IF SSR1> SSR2 → U = τ_{y1}

IF SSR1< SSR2 → L = τ_{y2}

IF SSR1= SSR2 →U= τ_{y1} , L = τ_{y2}

7- After re defining the upper and lower limits start the process again from step number one until 6.

8- Keep the process ongoing till the Upper and lower limit coincide at the same point which will be the Yield Point (τ_y).

9- After Getting the yield point, the indices n and K are calculated by the linear regression of

$$log(\tau - \tau_y) = \mathrm{Log}(\ K) + \mathrm{n.Log}(\gamma)$$

The Golden Section Search (GSS) Process is explained in **figure A.1**.

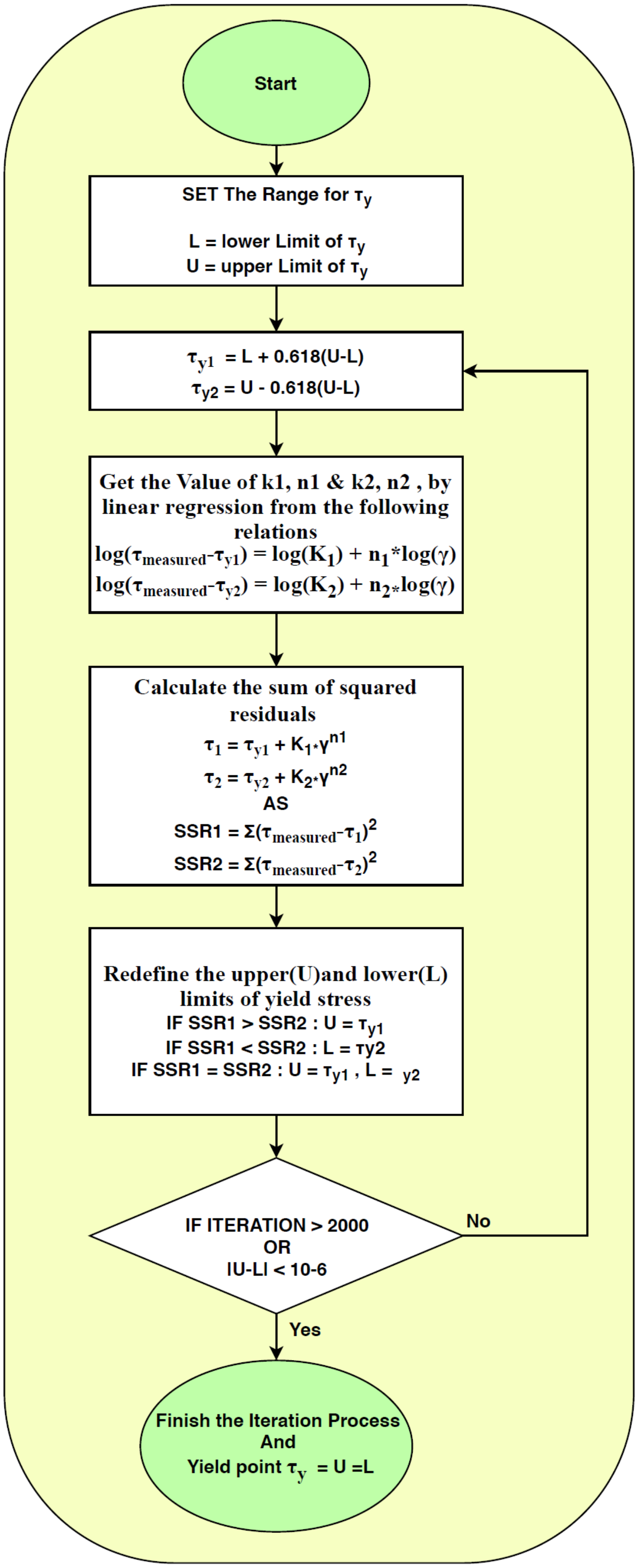

FIGURE A. 1: GOLDEN SECTION SEARCH, (THOTA RADHAKRISHAN A.K., VAN LIER J.B., AND CLEMENS F.H.L.R., 2018).

The Hydraulic calculations (API RP 13D)

Calculation of dynamic pressure loss :

The calculations are made based on Herschel-bulkley fluid model, as it's the most general fluid model to be utilized.

Hereby the summary of the calculations needed to get calculate pressure losses.

1- The calculation of the flow Velocity:

Fluid velocity inside the pipe (V_p)

$$V_p = \frac{24.51 * Q}{d_i^2}$$

Fluid Velocity inside the annulus (V_a)

$$V_a = \frac{24.51 * Q}{d_h^2 - d_p^2}$$

2- Hydraulic Diameter (d_{hyd})

Drill pipe

$$d_{hyd} = d_i$$

Annulus

$$d_{hyd} = d_h - d_p$$

3- Shear rate correction factor calculation

a. Well geometry and shear-rate correction

$$B_a = \left(\frac{(3-\alpha)n + 1}{(4-\alpha)n}\right) * \left(1 + \frac{\alpha}{2}\right)$$

$\alpha = 0$ for Pipes

$\alpha = 1$ for Annulus

b. Field viscometer shear – rate correction

$$B_x = \left(\frac{x^{2/n_p}}{n_p\, x^2}\right) * \left(\frac{x^2 - 1}{x^{2/n_p} - 1}\right) \cong 1$$

c. Combined shear rates geometry factor

$$G = \frac{B_a}{B_x} \cong B_a$$

4- Calculation of the shear rate at the wall

$$\gamma_w = \frac{1.6\, G\, V}{d_{hyd}}$$

5- Calculation of Shear stress at the wall

$$\tau_f = \left(\frac{4-\alpha}{3-\alpha}\right)^n \tau_y + K\, \gamma_w^n \qquad \text{(Viscometer units)}$$

$$\tau_w = 1.066 * \tau_f \qquad \text{(Engineering Units)}$$

6- Calculation of generalized Reynolds number

$$N_{ReG} = \frac{\rho\, V^2}{19.36\, \tau_w}$$

7- Flow Regime Identification

Laminar Flow → $N_{ReG} < 3470\text{-}1370n$

Turbulent Flow → $3470\text{-}1370n < N_{ReG} < 4270\text{-}1370n$

Transient Flow → $4270\text{-}1370n < N_{ReG}$

8- Calculation of friction factor

a. Laminar Flow Friction Factor (f_{lam})

$$f_{lam} = \frac{16}{N_{ReG}}$$

b. Transitional flow friction factor (f_{trans})

$$f_{trans} = \frac{16\, N_{ReG}}{N_{Cre}^2}$$

c. Turbulent flow friction factor (f_{turb})

$$f_{turb} = \frac{a}{N_{ReG}^b}$$

$$a = \frac{log_{10}(n_p) + 3.93}{50}$$

$$b = \frac{1.75 - \ log_{10}(n_p)}{7}$$

d. General friction factor, regardless of the flow regime present (f)

Calculate first an intermediate term (f_{int})

$$f_{int} = (f_{trans}^{-8} + \ f_{turb}^{-8}\ )^{\frac{-1}{8}}$$

Then calculate the general friction factor

$$f\ = (f_{int}^{12} + \ f_{lam}^{12}\ )^{\frac{1}{12}}$$

9- Calculation of friction pressure losses

a. Inside the drill string

$$p_{ds}\ = \ \sum \frac{1.076\ \rho_p V_p f\ L}{10^5 d_i}$$

b. Inside the Annulus

$$p_a\ = \ \sum \frac{1.076\ \rho_a V_a f\ L}{10^5 d_{hyd}}$$

Calculation of Circulation breaking pressure

It's the minimum pressure required to start the circulation of the mud after being static for a specific period of time (Assumed to be the 10 minutes).

a. Inside the drill string

$$p_{ds}\ = \ \sum \frac{G_{10m} L}{300\ d_i}$$

b. Inside the Annulus

$$p_a\ = \ \sum \frac{G_{10m} L}{300\ d_{hyd}}$$

Calculation of Surge and swab induced pressures

The movement of the drill string inside the wellbore will induce additional pressure changes in the wellbore, due to the change of the flow speed and profile in the annulus.

A typical representation of the flow velocity profile in the annulus with the movement of drill string for Herschel bulkily fluid is shown in **figure A.2** .

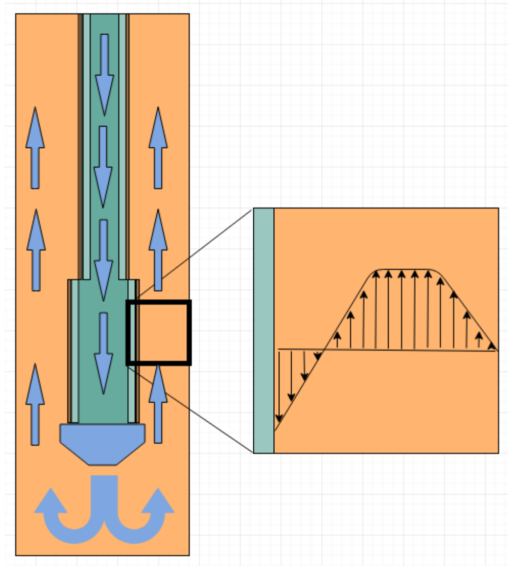

FIGURE A. 2: VELOCITY PROFILE DURING DRILLSTRING RIH

The movement of the drill string will induce flow of the mud in the annulus of the wellbore by two mechanisms (Volumetric and Viscous):

- The drill string volume will displace an equivalent amount of mud in the reverse direction.
  That will require us to take another factor into consideration; that the mud is allowed to enter through the drill string in reverse direction or not.
    a. Open End drill string (The mud can enter from the bit side); So, the displaced volume of mud is only by the steel volume of the drill string.
    b. Closed End drill string (i.e., Float Collar is installed); So, the displaced volume will be steel volume plus the fluids volume inside of it.
- The Clinging between the drilling fluid and the drill string wall surface.
  When the drill string moves up or down, the adjacent layer of the drilling fluid will be dragged in the same direction. By the rules of conservation of mass when this layer moves with the drill string an equivalent amount of mud will move in the reverse direction.

The exact calculation of the surge pressure will require numerical simulation of the fluid dynamics in the wellbore. For the purpose of that study it is enough to have numerical calculations with steady state calculations, which are recommended by API RP 13D. which is matching a comprehensive technique proposed by Clark & Fenton (1974) and utilizing Burkhardt (1961) technique to calculate the clinging viscosity clinging component of the speed, that is based on a semi-empirical method to calculate pressure surges, which shows a good match with actual field measurements.

From that principle, The term of annular fluid velocity can be expanded to include the surge and swab to be

$$V_a = V_{Pump} \pm V_{Clinging} \pm V_{Displacement}$$

Positive → to calculate the pressure drop with surge effect.

Negative → to calculate the pressure drop with swab effect.

Based on the recommendation of API RP 13D, The maximum drill string speed should be used in the calculations of surge/swab pressures. Because, the use of average speed will result in under-estimation of the surge pressures.

APPENDIX B: IADC Proposed Rating for MPD Techniques

This rating is Proposed by IADC, MPD subcommittee DEC.2011

Issue:	Continuous Circulation Devices	CBHP / Bottle Up or Trapped Pressure	CBHP / Back Pressure Control	CBHP / Back Pressure Control using gas in...	Dual Gradient Subsea Pump	Controlled mud level	Mud Line Pumping (Riserless)	Dual Gradient / Mix Fluid using gas	Dual Gradient / Mix Fluid using liquid	ECD Reduction Tools	ECD Control – Concentric Drill Pipe	Floating Mud cap	Pressurized Mud cap	RCD Only	Enhanced... /Loss Detection Only	UBD...	
LC Partial Losses	5	5	5	5	5	5	5	5	5	3	0	0	0	0	0	5	0
LC Severe Losses	3	5	5	5	5	5	5	5	5	0	0	3	3	0	0	5	0
LC Total Losses	0	3	3	3	3	3	3	3	3	0	0	10	10	0	0	5	[illegible]
Formation damage	3	3	3	3	3	3	0	3	3	0	0	3	3	0	0	10	0
Cementing Integrity	0	3	5	0	5	5	0	3	3	0	0	0	0	0	0	0	0
Enhanced/Accurate Kick / Loss Detection	0	3	5	0	5	5	3	0	3	0	0	0	5	0	5	3	0
Reduced Risk associated with Kicks	5	5	5	5	5	5	3	3	0	0	0	0	5	3	0	5	0
Reduce Influx Volume	0	5	5	3	5	5	3	0	3	0	0	3	5	0	3	0	0
Increase ROP	3	3	3	3	3	3	3	3	3	3	0	3	3	3	0	5	0
Drill in a liner	3	3	3	3	3	3	3	3	3	0	0	3	3	0	0	3	0
Elimination or extension of casing or liner	5	5	5	5	5	5	5	5	5	3	0	5	5	0	0	3	0
Extension or Elimination of Casing String in deep water	3	3	3	3	10	10	10	5	10	3	0	3	3	0	0	3	0
Drill through depleted formations	5	3	5	5	5	5	5	10	5	3	0	3	3	0	0	10	0
Abnormally High Pressure	3	3	5	0	5	5	5	3	3	0	0	3	5	3	0	3	0
Abnormally Low Pressure	3	3	3	5	3	5	3	5	3	0	0	5	3	0	0	5	0
Drilling HPHT Area	3	3	5	0	3	3	3	3	3	3	0	3	5	3	0	3	0
Formation Pressure Ramps	3	3	3	3	3	3	3	5	3	3	0	0	0	3	0	0	0
Geothermal	0	3	3	3	0	0	0	0	0	0	0	3	3	3	0	5	0
Drill thru Narrow Pore / Frac Gradient sections	5	5	5	5	5	5	5	5	5	3	3	3	3	0	0	3	0
Drill thru Narrow Collapse / Frac Gradient sections	5	3	5	3	5	5	5	0	3	3	3	0	0	0	0	-1	0
Reduce ECD effects	3	10	10	10	5	5	3	3	3	5	0	0	0	0	0	5	0
Extended Reach Drilling	3	3	5	3	3	3	3	3	3	0	0	3	3	0	0	3	0
Constant ECD or EMW	5	5	5	3	5	5	5	3	3	3	0	0	0	0	0	3	0
Decrease likelihood of Differential Sticking	5	5	5	5	5	5	5	5	5	0	0	3	3	0	0	5	0
Decrease potential for Wellbore collapse	5	3	5	3	5	5	0	0	3	0	0	0	0	0	0	-1	0
Control Well Bore Breathing / Ballooning	5	3	5	5	5	5	0	5	5	0	0	0	0	0	0	5	0
Maintain positive riser margin to reduce risk of blowout	0	0	0	0	5	5	-1	3	3	0	0	0	0	0	0	0	0
Avoid Shallow zone inflows - offshore - before surf csg	0	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	3
Avoid Shallow zone inflows - onshore	3	3	3	3	0	0	0	3	3	0	0	0	0	0	0	3	3
Reduction in lost circulation material	3	3	3	3	3	3	3	3	3	3	0	5	5	0	0	5	0
Mitigate Surge and Swab	5	0	3	3	5	5	0	0	0	0	0	3	3	0	0	0	0
Allow higher tripping speeds	3	0	0	0	5	5	3	0	0	0	0	3	5	0	0	0	0
Avoid pressure spikes with connections	5	5	5	3	5	5	3	0	0	0	0	0	0	0	0	0	0
Controlled Depletion of Shallow Hazards	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	0
Controlling Foamed Cementing	0	3	5	3	3	3	0	3	3	0	0	0	3	0	0	0	0

Rating	Description
(NA) -1	• The System/technology cannot be applied (exterior screen door on submarine, subsea BOP on land, etc.) and/or may also be detrimental to the operation with respect to the subject goal/objective (HSE risk, or significant increase in NPT, or an unnecessary increase in complexity, etc.). • The System/technology may provide a duplicate functionality with respect to the drilling rig and ancillary option in question. • The System/technology will need to overcome significant challenges to allow feasible application with respect to the subject goal/objective.
0	• The System/technology provides no obvious benefit or detriment to operations with respect to the subject goal/objective. • The subject goal/objective may be outside the scope or the intended functionality of the System/technology.
3	• The System/technology can provide some benefit (although it would not be considered to be one of its' primary objectives). Furthermore, some engineering work would be needed to realize this benefit, and to quantify the relative impact on operations, and other ancillary equipment or services.
5	• The subject goal/objective is one of the primary drivers or key design features of the System/technology.
10	• The subject goal/objective is considered to be the primary driver or key design feature of the System/technology.

FIGURE B. 1: IADC MPD TOOLS RATING

APPENDIX C: Studies Data

Table C1. Rheological data for bentonite–water suspensions and bentonite–lignite–water suspensions, for 12 drilling fluid samples.

TABLE C 1:RHEOLOGICAL DATA, (KELESSIDIS ET AL., 2005).

Shear Rate	S1	s2	S3	S4	S5	S6	S7	S8	S9	S10	S11	S12
1/S												
1021,38	28,5	48,42	21,92	6,92	10,25	20,75	18,17	11,75	12,83	4,5	9,33	12,17
851,15	27,75	46,83	22,75	6,17	8,92	19,25	16,67	11,08	9,75	4,17	8,58	11
680,92	26,83	44,58	26,08	5,58	7,83	17,92	14,75	9,75	8,58	3,58	7,92	9,83
510,69	25	41,58	22,42	4,75	5,92	17,08	12,75	8,58	8	3,08	6,83	8,33
340,46	22,58	37,83	18,58	3,67	4,75	15,17	9,92	6,58	7,33	2,42	5,58	6,83
170,23	21	35,67	13,58	2,17	3,42	12,33	6,5	4,25	5,58	1,75	3,42	4
136,18	21	33,25	12	1,83	3,08	11,67	6,17	4,08	5,42	1,5	2,92	3,42
102,14	20,08	30,83	10,5	1,33	2,92	10,75	5,75	3,75	5,08	1,42	2,42	2,75
51,07	16,67	27,42	6,92	0,58	2	9	4	2,58	4	1,08	1,5	1,58
34,05	17,5	27,83	7,42	0,5	1,67	8,83	4,17	2,42	4,17	1	1,33	1,42
17,02	16	21,9	6,67	0,08	1,25	8,08	3,33	2,08	3,67	0,67	1	1,17
10,21	14,67	23,75	6,25	0	1	8,17	3,25	1,83	3,67	0,58	0,58	0,92
5,11	13,2	19,9	5,1	0	0,5	7,7	2,8	1,6	3,25	0,5	0,5	0,1

Darquain Oil Field Data

Pore Pressure and Fracture Pressure Prediction Data

TABLE C 2: PRESSURE DATA, (NAKHOST A.T. ET AL.,, 2013).

Formation	TVD	Pore Pressure	Fracture Pressure	Casing
	(ft)	(ppg)	(ppg)	
Aghajari	0.00	8.60	11.67	17.5” Hole Section Surface Casing
Aghajari	820.2	8.60	12.51	
Mishan	3281.0	8.60	13.55	
Gachsaran	4035.6	8.60	15.01	
Gachsaran	4727.9	8.60	15.01	
Asmari	5367.7	8.60	13.55	
Jahrum	6922.9	8.60	13.55	
Jahrum	7287.1	8.75	13.67	
Pabdeh	7290.0	8.75	15.01	
Pabdeh	7533.1	8.75	15.01	12.25” Hole Section Open Hole
Gurpi	7874.0	9.00	15.22	
Gurpi	8697.9	9.96	15.59	
Ilam	8924.3	10.42	15.67	
Ilam	9058.8	10.72	14.59	
Sarvak	11224.3	10.72	14.54	
Kazhdumi	11782.0	11.60	15.84	
Dariyan	12139.7	11.60	15.84	
Upper Gadvan	12943.5	11.67	16.00	
Lower Gadvan	13051.0	11.67	17.84	
Lower Gadvan	13288.0	14.43	17.73	
Fahliyan Reservoir	13304.4	14.43	17.73	
Fahliyan Reservoir	13780.2	13.26	17.73	
Fahliyan Reservoir	15151.6	12.51	17.83	

Drilling Mud Rheological Parameters:

TABLE C 3: RHEOLOGICAL DATA FOR WELL DQ#5 , (NAKHOST A.T. ET AL,, 2013).

Rotor Speed, RPM	Dial Reading
600	60
300	40
200	30
100	20
3	3
2	2

TABLE C 4: DRILL STRING COMPONENTS, (NAKHOST A.T. ET AL,, 2013).

DrillString Description	ID	OD	Length	Distance from Bit
(From Bit to Top)	(in)	(in)	(ft)	**(ft)**
DC	2.81	8.00	30.80	**30.80**
St. Stab	2.81	12.25	4.82	**35.62**
DC	2.81	8.00	62.73	**98.35**
St. Stab	2.81	12.25	5.41	**103.76**
DC	2.81	8.00	180.90	**284.66**
Jar	2.81	8.00	16.53	**301.19**
DC	2.81	8.00	30.80	**331.99**
HWDP	3.00	5.00	460.78	**792.77**
DP	4.27	5.00	12511.00	**13304.50**

TABLE C 5: DRILLING PARAMETERS WELL DQ#5, (NAKHOST A.T. ET AL,, 2013).

Drilling Parameter	Min	Increment	Max
Circulation Rate (gpm)	707.0	10.0	767
Mud weight (ppg) used in lower 12¼" hole	14.22	0.03	14.31

TABLE C 6: MUD PROPERTIES, (ENI AGIP, 2005 FROM NAKHOST A.T. ET AL,, 2013).

Hole		24"	17 ½"	12¼"
Mud Type	Units	FW-GE	SW-PO-LS	SW-PO-LS
From	ft	0	820	7382
To	ft	820	7382	13304
Mud Density	ppg	8.75-9.17	9.17-11.5	12.5-14.7
Viscosity	sec-1	70	50-60	50-60
PV	cps	15-20	15-20	15-20
YP	lb/100 ft2	61	18-22	19-25
Gel 10"	lb/100 ft2	NA	2-4	2-4
Gel 10'	lb/100 ft2	NA	4-6	4-6
PH	-	9.5-10	9-10	9-10
Filtrate API	cc/30'	NA	<8	4-6
Pm	cm3 0.02N H2SO4	NA	1	1
Pf	cm3 0.02N H2SO4	NA	0.7	0.7

TABLE C 7: MUD SYSTEM DATA FOR WELL DQ#5, (ENI AGIP, 2005 FROM NAKHOST A.T. ET AL,, 2013).

		Density range	Mud volume
		(ppg)	(ft3)
24" hole section at 820 ft	Fresh water, bentonite (FW-GE)	8.75-9.17	17700
17½" hole at 7382 ft	Salt water, polymer-lignosulfonate system (SW-PO-LS)	9.17-11.5	77700
12¼" hole at 13304 ft	Salt water, polymer-lignosulfonate system (SW-PO-LS)	12.5-14.7	47700

TABLE C 8: HYDRAULIC PROGRAM, 17 ½" SECTION FROM 820 TO 7382 FT RKB, (ENI AGIP, 2005 FROM NAKHOST A.T. ET AL,, 2013).

Depth	**Mud Weight**	**Flow Rate**	**Pressure**	**Force**	**Annular Velocity**	**Nozzles**	**TFA**	**Pressure at bit**	**% Pressure at bit**	**Jet Velocity**	**Pressur e**	**Impact Force**
ft	ppg	gpm	psi	HHP	ft/sec	1/32"	in2	psi		ft/sec	HHP/in2	KG
1640	9.2	898	1251	662	1.306	3*18+1 *16	0.941	793	61.0	305	1.7	Kg
3821	10.1	898	1507	792	1.306	3*18+1 *16	0.941	867	55.0	305	1.8	648
4921	10.2	898	1678	886	1.306	3*18+1 *16	0.941	867	49.6	305	1.8	648
7218	10.2	898	2361	1241	1.306	3*18	0.745	1381	56.0	387	2.9	820
7382	10.2	898	2446	1288	1.306	3*18	0.745	1381	54.0	387	2.9	820

Questa è la verità……