A REPORT OF

# MAJOR PROJECT

ON

# "EXPERIMENTAL ANALYSIS OF WELLBORE STABILITY: CAUSES AND CONTROL"

SUBMITTED TO

UNIVERSITY OF PETROLEUM & ENERGY STUDIES

BY

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# CERTIFICATE

## University of Petroleum & Energy Studies

**The undersigned certify that they have read, and recommend to the Department of Petroleum Engineering & Earth Sciences, University of Petroleum & Energy Studies, for acceptance of Major Project submission Report entitled *"Experimental Analysis of Wellbore Stability: Causes and Control "* submitted by Agam Rawat in partial fulfilment of the requirements for the degree of Bachelor of Technology in Geosciences.**



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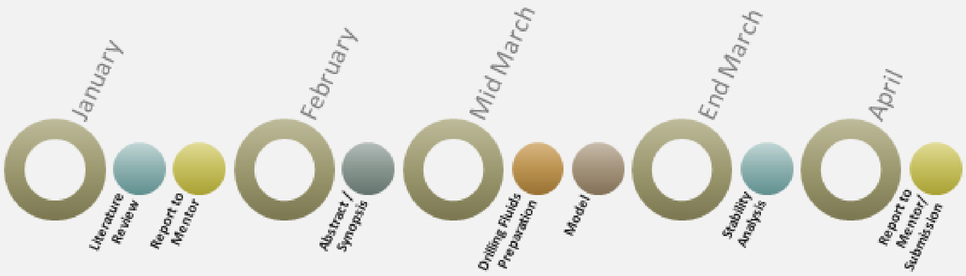
# PROJECT TIMELINE



# CHAPTER 1: WELLBORE INSTABILITY

The main cause for several wellbore problems encountered while drilling are often associated with unknown or unexpected behavior of the rocks, which results in the increase in non productive time (NPT) and eventually contributes to excess operational expenditure (OPEX). Hence the major concern for the drilling engineers is to keep the wall from falling or breaking down. For that major attention is provided to the drilling fluids program for uninterrupted drilling operations to minimize the costly problems. Major challenges in drilling practices arise while doing:

a. Underbalanced Drilling
b. Re-Entry Horizontal Wells
c. Multi-Laterals from single vertical or horizontal wells etc.

Henceforth, major components to monitor for mitigating wellbore instability problems are drilling rate of penetration (ROP), differential sticking, adequate hole cleaning, formation damage etc.

Drilling Fluids design is therefore an integral part to tackle these situations and optimize drilling, which is done through incorporating an efficient mud chemistry providing optimum Rheology and mud density, choosing appropriate additives for formation of filter cakes and also ornament the fluid with chemicals for tackling other formation lithology problems like in case of salt domes or shale or lose sandstone etc.

## CAUSES OF WELLBORE INSTABILITY

Several factors combine together to aid in wellbore instability problems and are broadly classified into two categories viz; CONTROLLABLE and UNCONTROLLABLE.

Controllable factors include:

1. Bottom Hole Pressure (Mud Density)
2. Well Inclination and Azimuth
3. Transient Pore Pressure
4. Physio-Chemical Rock Fluids Interaction
5. Drillstring Vibrations
6. Erosion
7. Temperature



Uncontrollable factors include:

1. Naturally fractured or faulted formations
2. Tectonically Stressed Formations
3. High In-Situ Stresses
4. Mobile Formations
5. Naturally Over-Pressured Shale Collapse
6. Induced- Over-Pressured Shale Collapse

## WELLBORE INSTABILITY: CONTROLLABLE FACTORS

### 1. Bottom Hole Pressure (Mud Density)

Mud density of the equivalent Circulating Density (ECD) application depending on the Bottom Hole Pressure (BHP) is a cardinal parameter which determines whether or not the open wellbore is stable. During different well operations such as drilling, stimulation jobs, workover jobs or production; the static or dynamic fluid pressure of the mud offers a supporting pressure to the wellbore to determine the stress concentration present in the near wellbore vicinity. As rock failure is dependent on the effective stress, the consequence for stability is greatly dependent on how fast the fluid pressure penetrates the wellbore wall. Although it would not be adequate to comment, that higher BHP and mud densities are always optimal for avoiding instability in a given well. For an instance, in the absence of a good filter cake, like in fractured formations, a rise in BHP may cause harm to stability and may compromise with formation damage, differential sticking risk, mud properties or hydraulics.

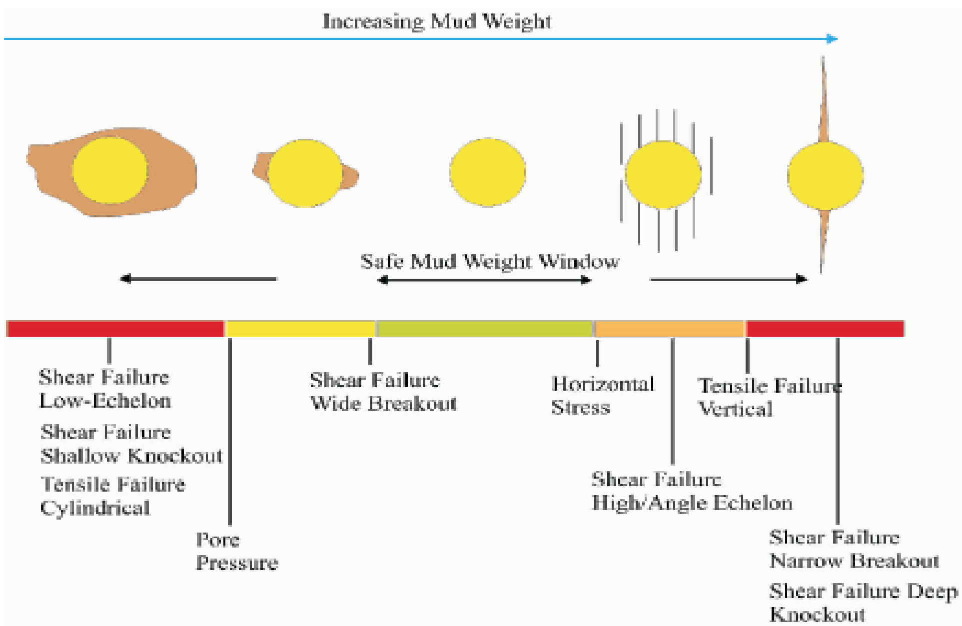



**Fig1: Effect of mud weight on the stress in wellbore wall**

### 2. WELL INCLINATION AND AZIMUTH

Inclination and azimuthal orientation of a well with respect to the principal in-situ stresses represents a cardinal factor affecting the risk of collapse and/or fracture breakdown. This is particularly true for estimating the fracture breakdown pressure in tectonically stressed regions where there is strong stress anisotropy.

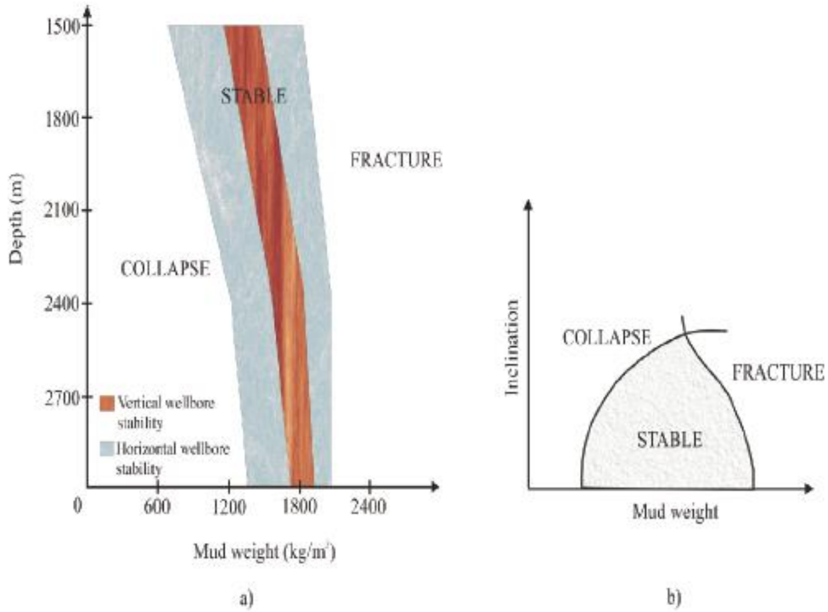



**Fig2: Effect of well depth (a) and hole inclination (b) on wellbore stability**

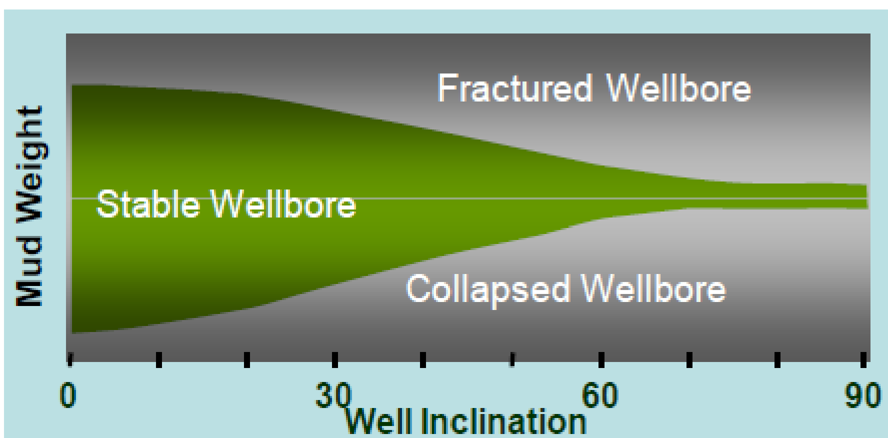



**Fig3: Mud weight window profile in inclined wellbore**

## 3. TRANSIENT PORE PRESSURE

Transient wellbore pressures, such as swab and surge effects during drilling, may cause wellbore enlargement. Tensile spalling can occur when the wellbore pressure across an interval is rapidly reduced by the swabbing action of the drill string. If the formation has a sufficiently low tensile strength or is pre-fractured, the imbalance between the pore pressures in the rock and the wellbore may bring rock off the wall. Surge pressures can also cause rapid pore pressures increases in the near-wellbore area causing an immediate loss in rock strength which may ultimately lead to collapse. Other pore pressure penetration-related phenomena may help to initially stabilize wellbores, e.g. filter cake efficiency in permeable formations etc

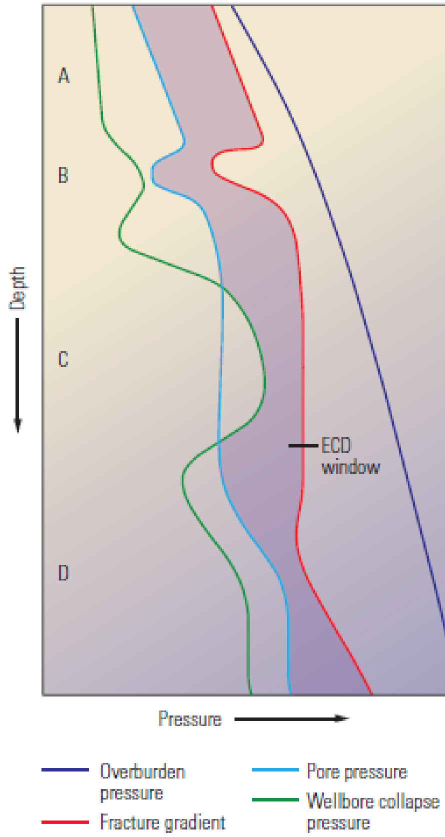



**Fig4: Pressure Gradient Regimes in a Wellbore**

## 4. PHYSIO-CHEMICAL ROCK FLUIDS INTERACTION

There are many physical/chemical fluid-rock interaction phenomena which modify the near-wellbore rock strength or stress. These include hydration, osmotic pressures, swelling, rock softening and strength change and dispersion. The significance of these effects depend on a complex interaction of many factors including the nature of the formation (mineralogy, stiffness, strength pore water composition, stress history, temperature), the presence of a filter cake or permeability barrier is present, the properties and chemical composition of the wellbore fluid, and the extent of any damage near the wellbore.

## 5. DRILLSTRING VIBRATIONS

Drillstring vibrations may cause enlarge of wellbores in some situations. Optimal bottom hole assembly (BHA) design with respect to the hole geometry, inclination, and formations to be drilled can sometimes eliminate this potential contribution to wellbore collapse. Some authors claim that hole erosion may be caused due to a too high annular circulating velocity. This may be most significant in a yielded formation, a naturally fractured formation, or an unconsolidated or soft, dispersive sediment. But this problem may be difficult to diagnose and fix in an inclined or horizontal well where high circulating rates are predominantly required to ensure adequate hole cleaning.

## 6. DRILLING FLUIDS TEMPERATURES

Thermal expansion inside the wellbore can occur due to the drilling fluids temperature, which poses a negative impact on the wellbore stability. This can be preferably mitigated with reduced drilling fluids temperatures that limit the near wellbore-stress concentration.

## WELLBORE INSTABILITY: UNCONTROLLABLE FACTORS

### 1. NATURALLY FRACTURED OR FAULTED FORMATIONS

Naturally fractured lithology can often be found near faults, which may cause problems like pipe stuck as rocks, if they are loose might fall inside the wellbore and jam the drillstring. Sometimes the vibrations of the bottom hole assembly (BHA) can loosen the bonded rocks and cause collapse problems. This can occur in tectonically fractured zones, for that drill string vibrations have to be minimized. Also, if weak bedding planes intersect the wellbore at unfavourable angles, then fractures may also cause mud invasions, gradually leading to strength degradation.

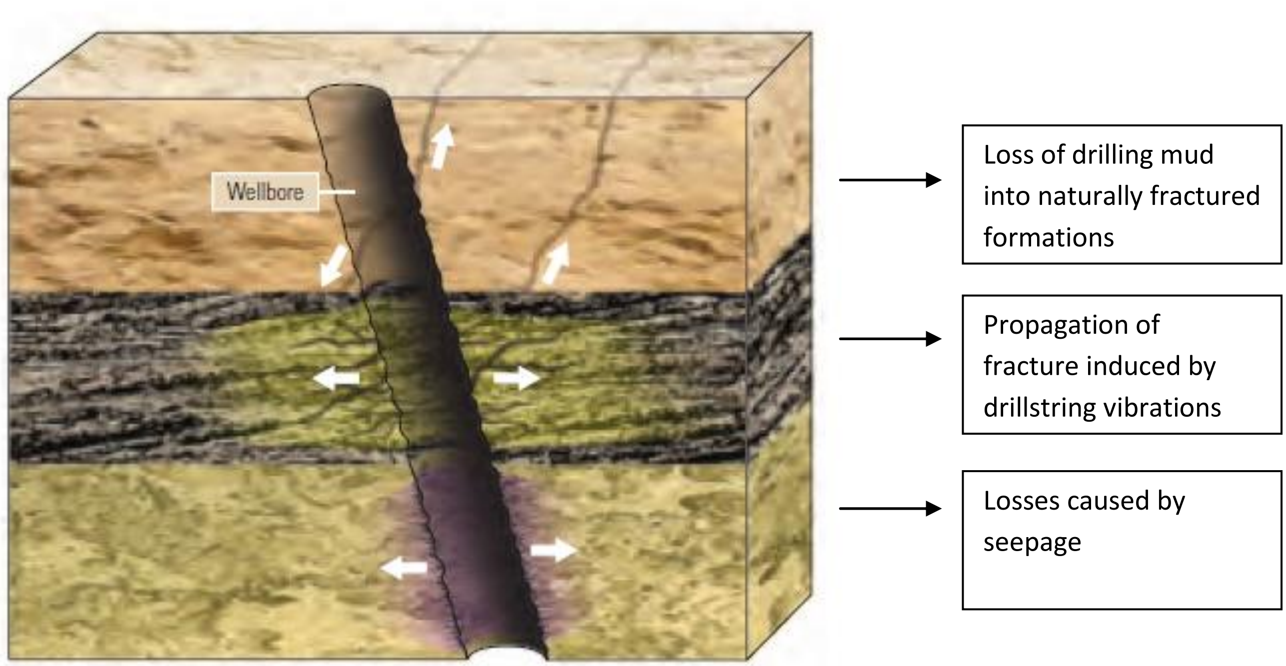



**Fig5: Types of Lost Circulation Events**

### 2. TECTONICALLY STRESSED FORMATIONS

While drilling highly stressed formations, wellbore instability problems are encountered and if exists a significant difference between the near wellbore stress and the restraining pressure provided by the drilling fluid density. Tectonic stresses build up in areas where rock is being compressed or stretched due movement of the earth´s crust. Due to tectonic forces, the rocks are buckled up under pressure arising due to plates movement.

When a hole is drilled in an area of high tectonic stresses the rock around the wellbore will collapse into the wellbore and produce splintery cavings similar to those produced by over-pressured. In the tectonic stress case the hydrostatic pressure required to stabilize the wellbore may be much higher than the fracture pressure of the other exposed formations. This mechanism usually occurs in or near mountainous regions. Planning to case off these formations as quickly as possible and maintaining adequate drilling fluid weight can help to stabilize these formations.

### 3. HIGH IN-SITU STRESSES

Anomalous variations in the in-situ stresses encountered such as found in the vicinity of salt domes, near faults, or in the inner limbs of a fold may give rise to wellbore instability. Stress concentrations may also occur in particularly stiff rocks such as sandstones or conglomerates. Only a few case histories have been described in the literature for drilling problems caused by local stress concentrations, mainly because of the difficulty in measuring or estimating such in situ stresses.

## 4. MOBILE FORMATIONS

Overburden forces tend to squeeze the subsurface mobile formations like salt into the wellbore. Mobile formations behave in a plastic manner, deforming under pressure resulting in a decrease in the wellbore size, causing problems of running BHA´s, logging tools and casing. A deformation occurs because of the inadequate mud weight, not sufficient to prevent the formation squeezing into the wellbore.

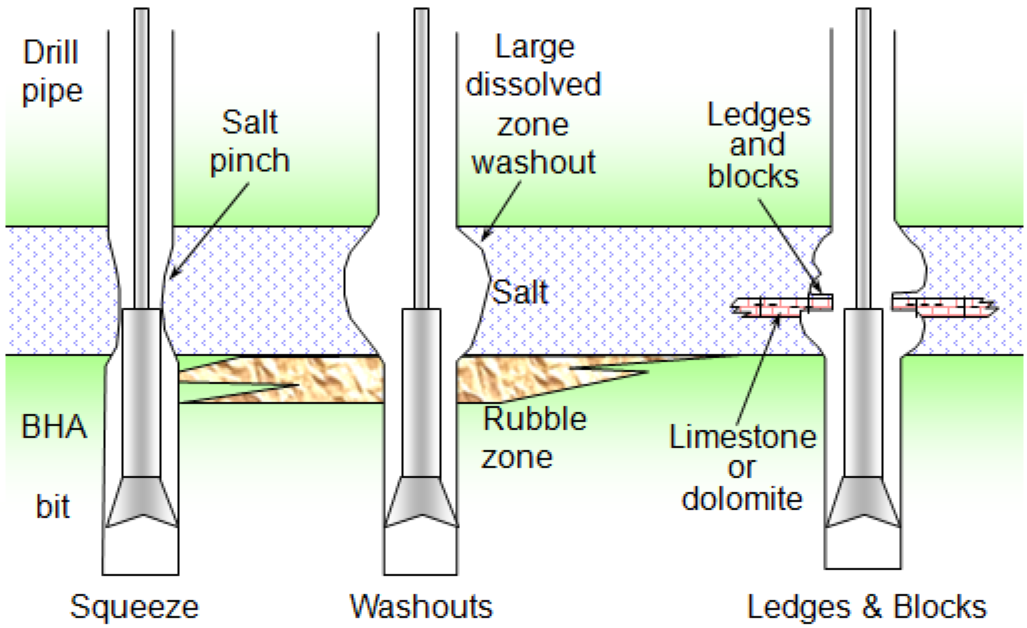



**Fig6: Drilling Problems associated with Salt Formation**

## 5. UNCONSOLIDATED FORMATIONS

Loose unconsolidated rock formations fall into the wellbore because of no bonding between particles, pebbles or boulders. The collapse of formations is caused by removing the supporting rock as the well is drilled. It occurs due to poor formation of filter cake in the wellbore. The un-bonded formation (sand, gravel, etc.) cannot be supported by hydrostatic overbalance as the fluid simply flows into the formations. They then falls into the hole and packs off the drill string.

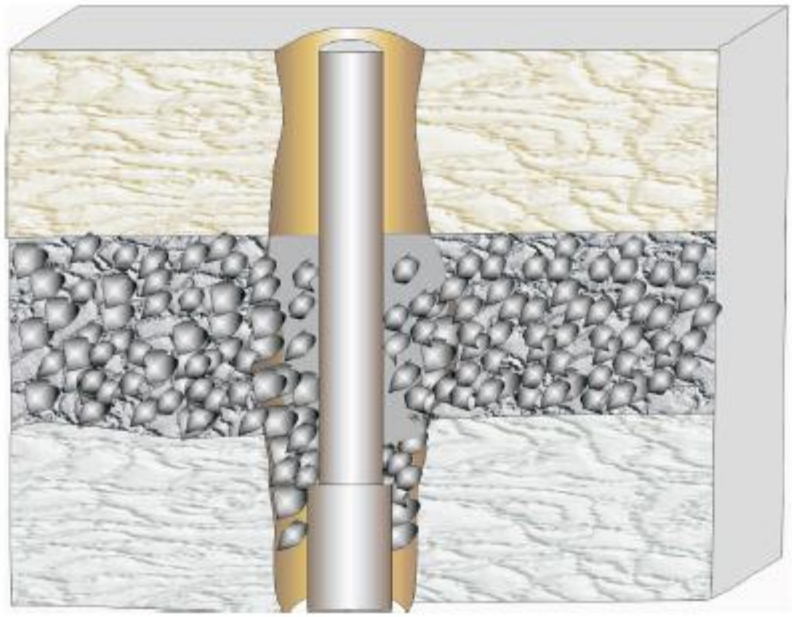


**Fig7: Drilling through Unconsolidated Formation**

## 6. NATURALLY OVERPRESSURED SHALE

Naturally over-pressured shale is the one with a natural pore pressure greater than the normal hydrostatic pressure gradient. Naturally over-pressured shales are most commonly caused by geological phenomena such as under-compaction, naturally removed overburden and uplift. Using insufficient mud weight in these formations causes the hole to become unstable and collapse. This mechanism normally occurs in rapid depositional shale sequences. The short time hole exposure and an adequate drilling fluid weight can help to stabilize these formations.



## 7. INDUCED OVERPRESSURED SHALE

Induced over-pressured shale collapse occurs when the shale assumes the hydrostatic pressure of the wellbore fluids after a long exposure to that pressure. When this is followed by no increase or a reduction in hydrostatic pressure in the wellbore, the shale, which now has a higher internal pressure than the wellbore, collapses in a similar manner to naturally over-pressured shale. This mechanism normally occurs in water based drilling fluids, after a reduction in drilling fluid weight or after a long exposure time during which the drilling fluid was unchanged.

# CHAPTER 2: DIAGNOSIS OF WELLBORE INSTABILITY (FIELD CASE)

Wellbore instability manifests itself in different ways like hole pack off, excessive reaming, overpull, torque and drag, sometimes leading to stuck pipe that may require plugging and side tracking. This requires additional time to drill a hole, driving up the cost of reservoir development significantly. In case of offshore fields, loss of hole is more critical due to a limited number of holes that can be drilled from a platform.

Design of wells using principles of rock mechanics is well reported in the literature (Wong et al., 1994; Morita and Whitebay, 1994). A case study of designing a horizontal well in Vlieland sand in the Dutch sector of North Sea is reported by Fuh et al. (1991). The rock mechanical parameters such as in-situ stresses, strength and pore pressure of the Vlieland sand and shale which overlies it were computed from the back analysis of drilling problems from previous eight vertical wells drilled in the area. A mud program was designed using these estimated parameters and a horizontal hole was drilled with few manageable instances of instability.

Drilling of overburden shales in offshore Nigeria resulted in several problems of stuck pipes and sidetracks. A detailed rock mechanics study was conducted to characterize the state of in-situ stress, rock strength, and formation pore pressure. These parameters were used to perform a geomechanical simulation and estimate safe mud weights. Use of these mud weights led to a marked improvement in wellbore stability (Lowrey and Ottesen, 1995). Four wells drilled in Gulf of Suez and Mediterranean Sea, offshore Egypt, were analyzed for wellbore instability, to improve drilling performance in future wells (Hassan et al., 1999). A suite of logs, including DSI sonic, GR, and density were used as input to IMPACT-ELAN of Geoframe to predict rock strength, petrophysical properties, and safe mud weight windows. The weak shales in the overburden were failing due to inadequate wall support inspite of using oil based mud (OBM). The simulation predicted higher mud weight for adequate wall support. Use of predicted higher mud weights during drilling improved the hole condition and related instabilities. Therefore, OBM used of to drill shaly sections should be checked for correct mud weight.

Saidin and Smith (2000) discussed wellbore instability encountered when drilling through the Terengganu shale (K-shale), Bekok field, Malaysia. Due to the time dependency of the observed instability cases, K-shale was thought of as reactive and unstable due to shale– fluid interaction. Invert emulsion OBM was used to drill the wells. This, however, resulted in severe formation damage without any improvement in stability. Rock characterization and laboratory measurements of rockmechanical properties indicated that K-shales had predominantly non-reactive weak clay. This information helped in improving the design of mud weight window leading to successful completion of a new well. To minimize differential sticking due to high mud weights, invert emulsion SBM was used.

In many cases, factors like magnitude of the maximum horizontal in-situ stress and variations in rock strength are not well known. These parameters are estimated using empirical or semi-empirical approaches.

Under such circumstances, the safe mud weight window predicted using geomechanical simulation is often not realistic. For such cases, drilling data accumulated from previous problematic wells can be used to predict safe mud weight window. A brief review of studies using the above mentioned approach is given in the following paragraphs. Santarelli et al. (1996) presented wellbore instability problems occurring in a developed field in Italy. The problems were back analyzed with respect to the mud types, mud weights, azimuths, and stress regime. More drilling problems like reaming and stuck pipe occurred in a particular azimuth. This proved the existence of anisotropic distribution of horizontal stresses, which was not known because of absence of any in-situ stress related data. The non-inhibitive water based mud gave better results compared to other mud system. In the light of new data, drilling practices which were planned during appraisal drilling phase were continued with necessary modifications.

Santarelli et al. (1992) presented a case study of drilling in highly fractured volcanic rocks at great depths. Use of OBM did not solve the problem since the instability was not due to clay. Analysis of the clay in those rocks showed that they were non-reactive. It was found that the main mechanism of instability was mud penetration in fractures which led to eventual erosion of the wellbore wall due to inadequate wall support.

Appropriate mud weight was designed by simulating the fractured rock mass using discrete element modeling. Use of the new mud weight, lower than that being used, along with proper fracture plugging material in WBM proved successful. Classical method of solving the instability by increasing mud weight could have aggravated the problem.

In general, wellbore instability is caused by a combination of different reasons or presence of more than one mechanisms of instability. Wells drilled in complex geological areas encounter many layers of rock having different properties. Some layers could be weak, while others brittle, fractured, chemically reactive or rubble. There is no simple solution for wellbore instability in such cases. A collapsing weak layer needs high mud weight for stability, but increasing the mud weight could excite instability in fractured layers by mud invasion. Therefore, such cases require careful rock characterization and mud weight optimization. In the past, fields were developed using vertical wells which did not exhibit any drilling trouble. The trend nowadays is to drill horizontal wells to enhance productivity. The experience of drilling vertical wells is carried forward without appropriate modifications to drill the horizontal wells resulting in wellbore instabilities.

Severe instability was encountered while drilling horizontal drains in Hamlah-Gulailah Formation, ABK field, offshore Abu Dhabi, though vertical wells were drilled without encountering any significant problem.

To analyze the instability problem, a comprehensive rock mechanical study was carried out to characterize rock strength and in-situ horizontal stresses. The study suggested that the horizontal stresses were anisotropic in nature with strike–slip–thrust stress regime. The rocks were weak and fissured. The rock mechanical simulation predicted higher mud weights than those actually used in the field (Onaisi et al., 2000).

Al-Buraik and Pasnak (1993) discussed well plans, drilling fluids, casing and cementing liners, coring, logging, completions, and drilling problems encountered in more than a dozen horizontal wells drilled both in sandstone and carbonate reservoirs in Saudi Arabia. The wellbore, in sandstone reservoirs, passed through shale and shale–sand stringers before reaching TD (target depth). Because of the consolidated nature of thesand, these wells are completed with 7" LNRs (liners). Three wells suffered from major wellbore instability problems such as borehole collapse leading to stuck pipe. The collapse due to the mechanical instability of shale was aggravated due to extended exposure time. Some of the shale layers needed a minimum mud weight of 92 PCF (12.3 PPG) in order to keep the borehole open. Several stuck liners and casings were experienced in holes drilled with motor. This problem was partially solved by reaming the motored hole with stiff, nondrilling reaming assembly before running the liner or casing.

Ezzat (1993) discussed different laboratory tests performed for suitable mud design for drilling Khafji and other reservoirs in Saudi Arabia. The petrophysical examination of Khafji cores revealed that the formation was basically sandstone with shale stringers, shaly sand, coal/lignite/amber (plant remains and fossilized tree resins) and iron rich shale/sand near the top of the reservoir. The shale was characterized as water-sensitive with kaolinite up to 49 wt.%, chlorite up to 19 wt.%, and mixed layer illite/montmorillonite up to 13 wt.%. This unstable shale caved in, if proper mud weight was not used during drilling. In some instances mud weights greater than formation fracture pressure had to be used to keep the hole open. Use of oil-based mud resulted in reduction of wellbore instability cases. Among the reasons that caused mechanical instability were erosion of unconsolidated sand, gas cut mud and hole fill after trip, pipe whip and drillstring sticking. Appropriate actions were taken to solve these problems.

Thus several studies have been conducted to design safe mud weight window using field drilling data. In this paper, wellbore instability as a function of shale–mud interaction, rock mechanical simulation, safe mud weight prediction, and analysis of drilling data has been studied. This paper proposes new parameters not used so far to develop a method of wellbore instability analysis and calculation of safe mud weight window. This method of analysis is very useful when in-situ stress data and rock strength data are not available or where there is significant variation in rock properties through different formation layers.

## RESERVOIR GEOLOGY AND DRILLING OUTCOMES

The field under study can be divided into three main lithological sequences. The upper part has predominantly shale with coal and sand stringers. The middle part has clean sand and the lower part has sand and shale stringers. The target zone for the development wells has clean sand. The trajectories of these wells in shale– coal–sand stringers of the upper zone are highly deviated and long. Since longer deviated trajectories have to be drilled, it takes more time to drill, giving rise to delayed problems like tight hole, hole pack off, and irremedial stuck pipe which require side tracking. The initial development of the field was done by drilling vertical and directional wells. Drilling problems like tight holes, high torque and drag were common but manageable. Later, during infill drilling, highly deviated and horizontal wells were drilled. The drilling problems became severe leading to stuck pipes. Some of the holes had to be side tracked.

## CHARACTERIZATION OF BOREHOLE STABILITY

Drilling data of sixty wells from the field was analyzed in this study. There were nine vertical, fifteen directional and the rest horizontal wells. As shown, the compiled data of instability instances from the daily drilling reports (DDR's) show that tight-holes represent the majority of instability instances (65%), followed distantly by stuck pipe (13%) and hole packoff (8%),80% of these problems occurred during hole control. Typically hole control problems occur before or during the placement of casing, therefore they are time delayed.

The type of drilling problems indicate that the hole size is decreasing with time. This can happen due to many reasons such as presence of mobile formations, hydration of shales, presence of cavings and cuttings, and mud cake. A shale characterization study, described in the next section, was conducted to check if shale swelling is leading to tight hole and stuck pipe situations. Geomechanical simulation was also conducted to predict the safe mud weights. However, the range of mud weights predicted by geomechanical simulation was not compatible with field observations. The deficiency was mainly due to lack of enough rock mechanical data.

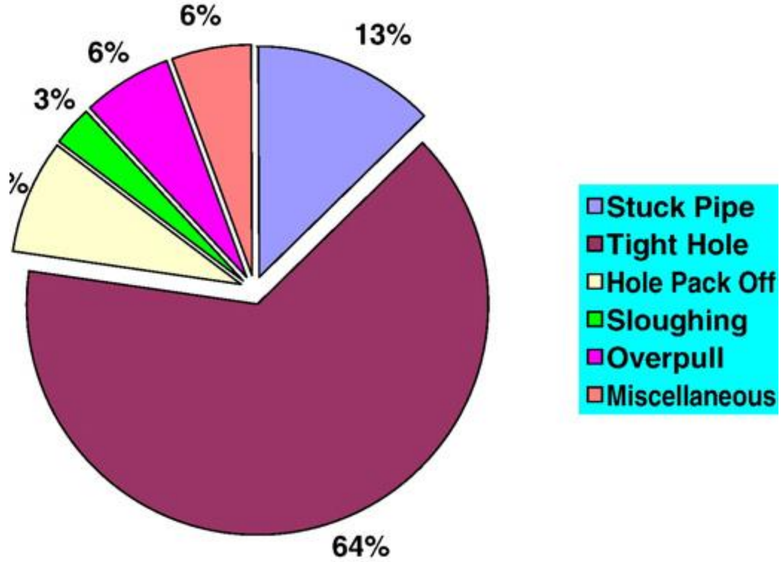



**Fig8: Hole Problems in the Field (Case)**

In view of the above, the huge amount of field data— from geology to DDR's was used to study the instability mechanisms and safe mud weights. This technique proved successful and was validated. It is described below after a brief account of shale and geomechanical simulation studies.

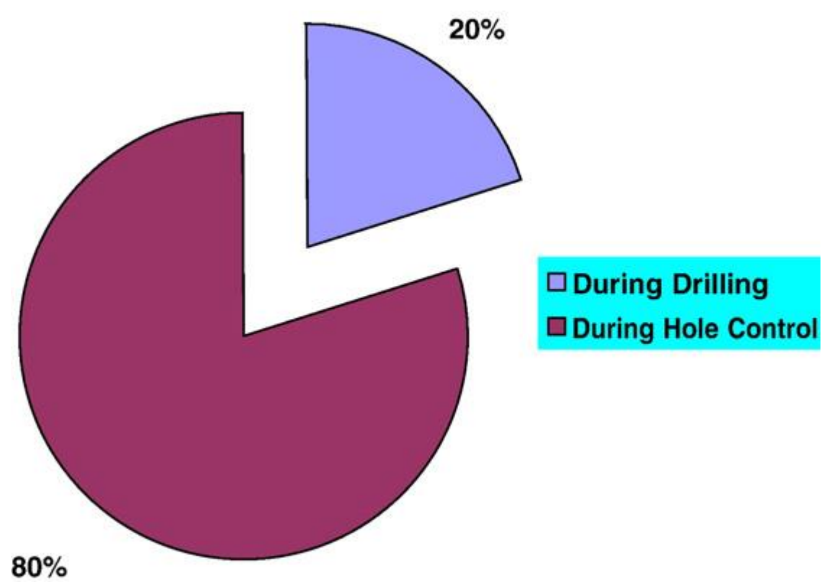



**Fig9: Hole Problem Remarks**

## SHALE STUDY

The study of open hole logs showed large washouts at shale sections. There can be two reasons for these washouts, chemical and mechanical. Reactive shales can interact with water and fail leading to washouts. To check this, two pieces of shale were soaked for 3 weeks in two brine solutions, each having different salinity (1 K and 250 K ppm). No significant change was observed in both the samples indicating absence of chemical reactivity in the shale.

The shale samples were highly laminated with thin bedding planes. Core plugs perpendicular to the bedding planes could not be drilled because the shale sample disintegrated into flakes during drilling. However, few plugs could be cut parallel to bedding planes. The plugs were fissile, brittle and were black in color, indicating presence of organic material. They were highly heterogeneous with alternating layers of silt, sand, shale and organic matter. Coal seams and amber were visible to the naked eye whereas salt crystals were also visible under microscopic examination. The formation brine perhaps had high salinity leading to the deposition of salt in pores after evaporation of water.

The thin section and SEM-EDS analyses of the shale confirmed the presence of layers containing very fine sandstone and carbonaceous material. Partings occur in black carbonaceous material suggesting weak cohesion of this material. There is presence of open, partially healed and fully healed microfractures in some shale samples. This indicates that the failure of shale sections represented by washouts may have been caused by its brittle and fissile nature. Mud invasion through the open microfractures and partings may have led to the loss of overbalance leading to washouts.

## ANALYSIS OF VERTICAL WELLS

A range of initial mud weights form 69 to 82 PCF was used to drill vertical wells. The data is used to evaluate the performance of mud weight with respect to the number of problems encountered. There is a very weak correlation between initial mud weight used and number of problems encountered. But if the analysis is limited to the mud weight range of 70–75 PCF, the numbers of problems show a monotonous decrease from nine to zero. Only one point is before 70 PCF is not following the trend.



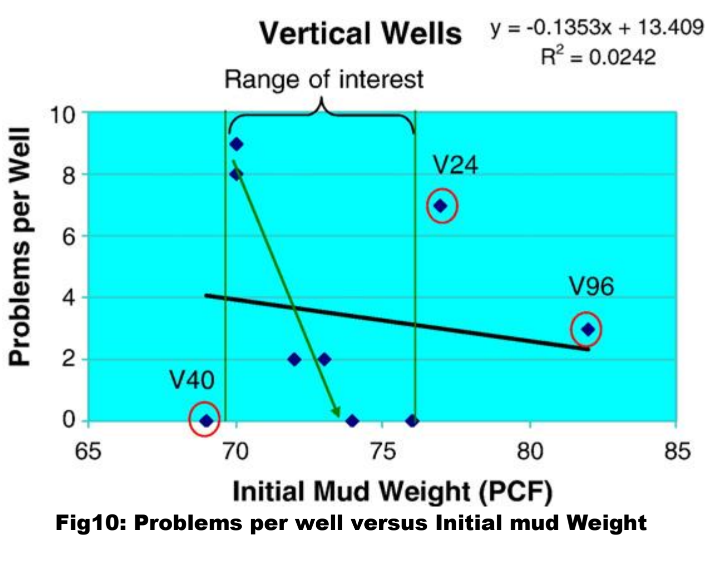



**Fig10: Problems per well versus Initial mud Weight**

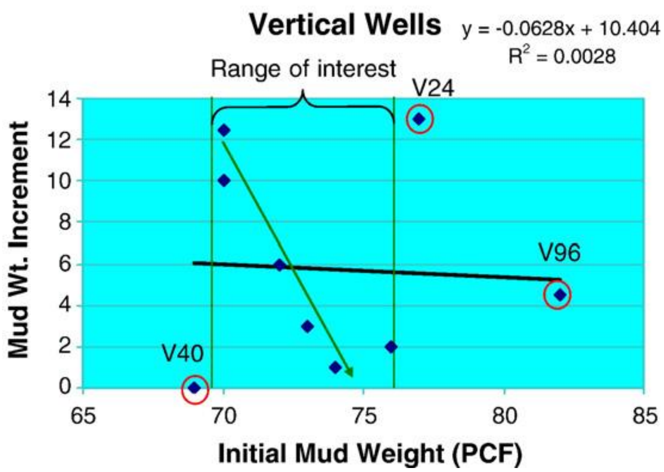



**Fig11: Mud Weight Increment VS Initial Mud Weight of the Well**

The analysis indicates that even though there were washouts in the well, no instability problems were reported perhaps because of efficient cleaning or slow drilling. Points beyond 75 PCF represent those cases where other instability mechanisms such as mud invasion were active. Usually, instability is managed by increasing the mud weight. As observed in Fig. 4, in the range of 70–75 PCF, the maximum mud weight increment was applied for wells drilled with lower initial mud weights. The mud weight increment decreases monotonously in this range, confirming the observation that wells drilled with a starting mud weight of around 75 PCF were the most stable. The trend usually followed in industry is confirmed in Fig. 5. As shown in the figure, a strong correlation is observed between the number of problems encountered and the mud weight increment to counteract the instability. The initial mud weight was not high enough to support the wall resulting in washouts and the subsequent problems. The mud weight increments have significantly helped in decreasing these problems, as evident in the figure.

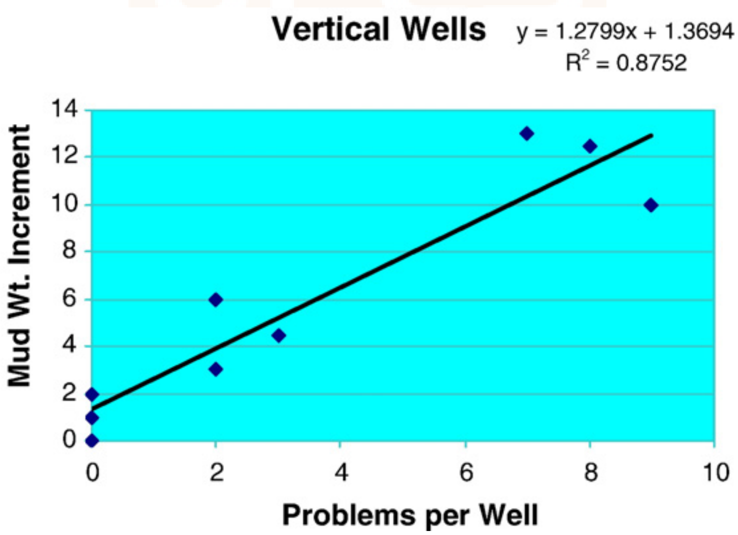



**Fig12: Mud Weight Increment VS Well Problems**

It is observed that the hole enlargement is decreasing with the increase in mud weight in the range of 70–76 PCF. Interestingly, contrary to the normal expected trend, the hole enlargement increased for the mud weight value beyond 76 PCF.The wellbore wall stabilization as indicated by decreased washout with increase in mud weight isclearly evident. However, when mud weight is greater than 76 PCF, increase in hole size (washouts) at certain locations were observed. This increase in washouts could possibly be due to the mud invasion at high overbalance. For the wells in the range of 70–76 PCF, the problems per well increased with enlargement. The wells drilled with higher mud weight do not follow this trend, and show more problems per well at smaller enlargements. This is because these wells experienced drilling problems such as overpull and stuckpipe due to high overbalance. The origin of problems for wells drilled in the range of 70–76 PCF was the increased volume of cuttings and cavings in the hole. Hence the problems increased with increase in enlargement. It can readily be inferred from this information that the drilling difficulty was due to the extra amount of cuttings and cavings present in the hole. This can be controlled by the use of correct mud weight. If mud weight is high, it gives rise to problems due to differential sticking and mud invasion or pore pressure penetration. Hence, optimizing the mudweight to reduce the volume of cavings as well as avoid differential sticking or mud invasion is essential.

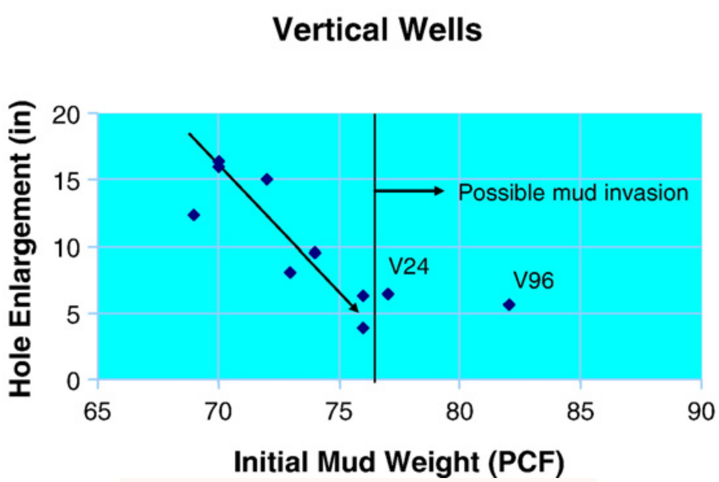



**Fig13: Hole Enlargement VS Initial Mud Weight**



From the analysis of initial mud weight, mud weight increment, problems per well and hole enlargement of vertical wells, three instability mechanisms have been identified. If sufficient mud weight is not used, wellbore wall support is not available and the wellbore wall collapses. The instability due to wellbore wall collapse can be avoided by using appropriate mud weight that adequately supports the wall. Other instability mechanisms are mud invasion and differential sticking at higher mud weights. Therefore it is essential to drill vertical wells using an optimum mud weight that avoids the above instability mechanisms.

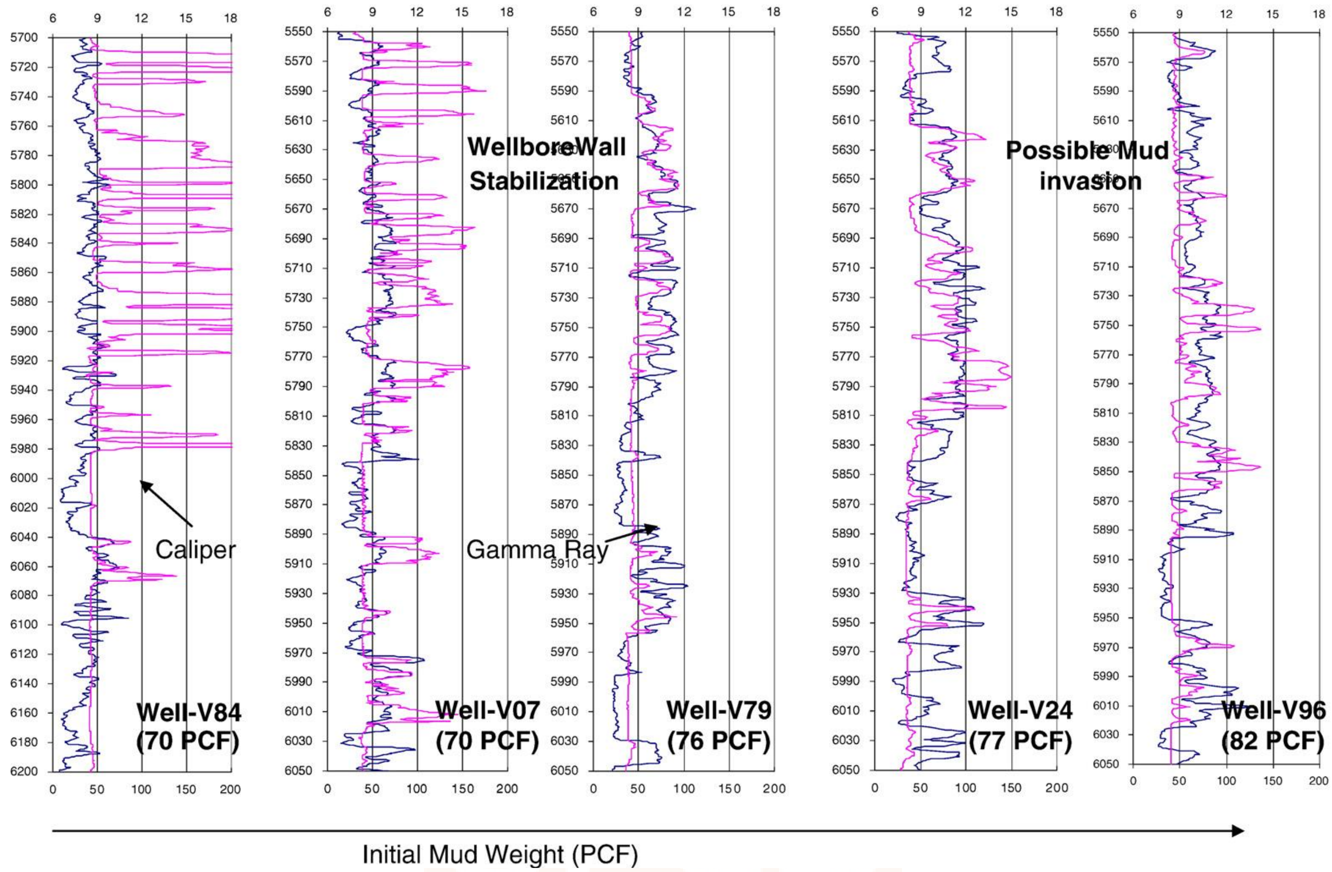



**Fig14: Open-hole caliper log of selected vertical wells showing wellbore wall support and possible mud invasion**

# CHAPTER 3: EXPERIMENTAL ANALYSIS

The experimental analysis to understand the wellbore stability mechanisms is conducted in two different phases namely;

**Phase A: Preparation of Drilling Fluid Systems for different targeted stability concepts**

**Phase B: Testing of the prepared samples on different experimental setups**

The targeted area for understanding the wellbore stability is confined only to:

a. Shale Stability
b. Sand Stability
c. Salt Mobility Stabilization

Mud systems prepared for the above three conditions are:

a. KCl Polymer Mud System
b. Bentonite-Gel Mud System
c. Salt saturated Polymer Mud System respectively.

All the experiments are elaborated in details discussing the following components:

A. Drilling Fluid Preparation
B. Working Mechanism
C. Experimental Run
D. Analysis and Inference



| S.NO | EXPERIMENT NAME | MUD SYSTEM | CONTROL PARAMETER |
|---|---|---|---|
| **1.** | SHALE STABILITY ANALYSIS | KCl Polymer | Shale Inhibition |
| **2.** | SALT STABILITY ANALYSIS | Salt saturated Polymer | Salt Mobility |
| **3.** | SAND STABILITY ANALYSIS | Bentonite-Gel | Unconsolidated sand control |

Table1: Experimental Details

## EXPERIMENT 1: SHALE STABILITY ANALYSIS

**EXPERIMENT DATE:** March.19.2015

**MUD SYSTEM:** Water Based Mud (WBM)

**MUD TYPE:** KCl Polymer

**TEST SPECIMEN:** Shale Cuttings

### A: DRILLING FLUID PREPARATION

- Water is the continuous phase in the mud.
- Different additives added in definite proportions within water.
- The fluid is mixed using Hamilton Mixer for different time gaps at different speeds.
- The drilling mud is tested for identifying rheological parameters using Rheometer at different RPM's
- The mud weight is determined using Mud balance and reading noted.

### B: WORKING MECHANISM

Potassium is one of the most effective ions available to inhibit shale hydration. Potassium performance is based on cation exchange of potassium for sodium or calcium ions on smectite and interlayered clays. Potassium ions work better than other inhibitive ions because of its structure. Potassium ions fit more closely into the clay lattice structure and thereby reducing swelling or hydration of clays. The potassium ions are of proper size to fit into the spaces between the two silica tetrahedral layers which contact each other in the formation of a three layered clay packets. The ionic diameter of potassium ion is 2.66A where as available space between the lattices structure of clay is 2.8A. A cation slightly smaller than 2.8A is desirable to allow for crystalline compaction. When the formation is dominantly montmorillonitic the potassium ion exchange for sodium and calcium results in less hydratable structures. Potassium system work best when polymers are used for encapsulation. During drilling operation shale cuttings should be monitored very carefully for proper inhibition. If the concentration of KCL in the mud is not sufficient then shale cuttings will appear soft and mushy at the shaker.

**C: EXPERIMENTAL RUN:**

1. **FLUID PROPERTIES:**

**MUD FORMULATION**

| S.NO | MUD CONSTITUENT | CONCENTRATION (ppb/gram) | FUNCTION |
|---|---|---|---|
| **1.** | Water | 289 | Continuous Phase |
| **2.** | Caustic Soda | 0.25 | pH Control |
| **3.** | Soda Ash | 0.25 | Treat Calcium/Magnesium |
| **4.** | Barite | 165 | Weighting Agent |
| **5.** | Potassium Chloride | 35 | Shale Inhibitor |
| **6.** | Starch | 5 | Fluid Loss Control Agent |
| **7.** | Xanthan Gum | 1 | Viscosifier |

Table2: Mud formulation- KCl Polymer Mud

**EXPERIMENTAL READINGS**

- **Mud Density (ppg):** 11.8
- **Rheometer Readings:**

| S.No | RPM | Reading |
|---|---|---|
| **1.** | R600 | 71 |
| **2.** | R300 | 48 |
| **3.** | R200 | 38 |
| **4.** | R100 | 26 |
| **5.** | R6 | 12 |
| **6.** | R3 | 11 |

Table3: Rheometer Readings- KCl Polymer Mud

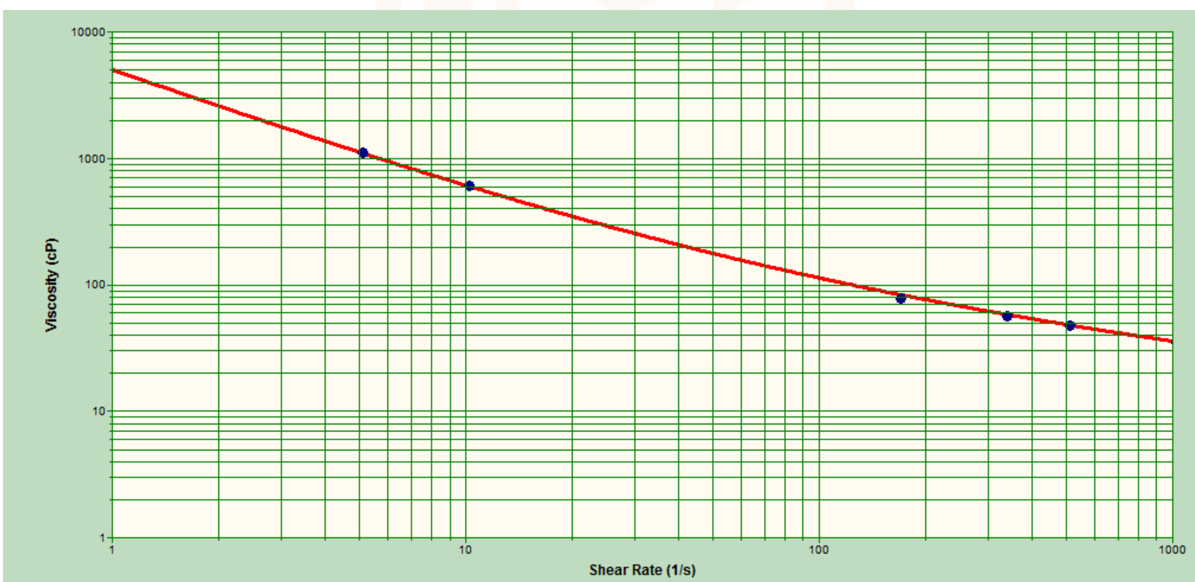
- **Parameters Calculated:**

| S.No | Mud Parameters | Calculated Values |
|---|---|---|
| **1.** | Plastic Viscosity, cp | 23 |
| **2.** | Yield Point, lb/100ft2 | 25 |
| **3.** | Gels, 10sec, lb/100ft2 | 11 |
| **4.** | Gels, 10 min, lb/100ft2 | 22 |
| **5.** | Gels, 30min, lb/100ft2 | 28 |

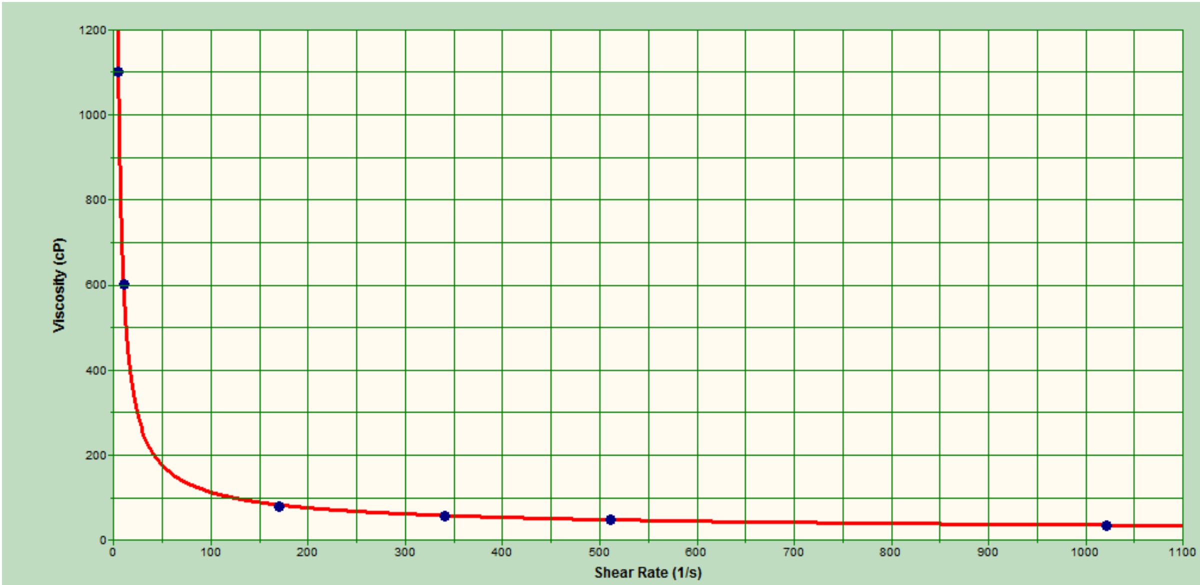
Table4: Mud Parameters- KCl Polymer Mud

**GRAPHS: KCl Polymer Mud System**

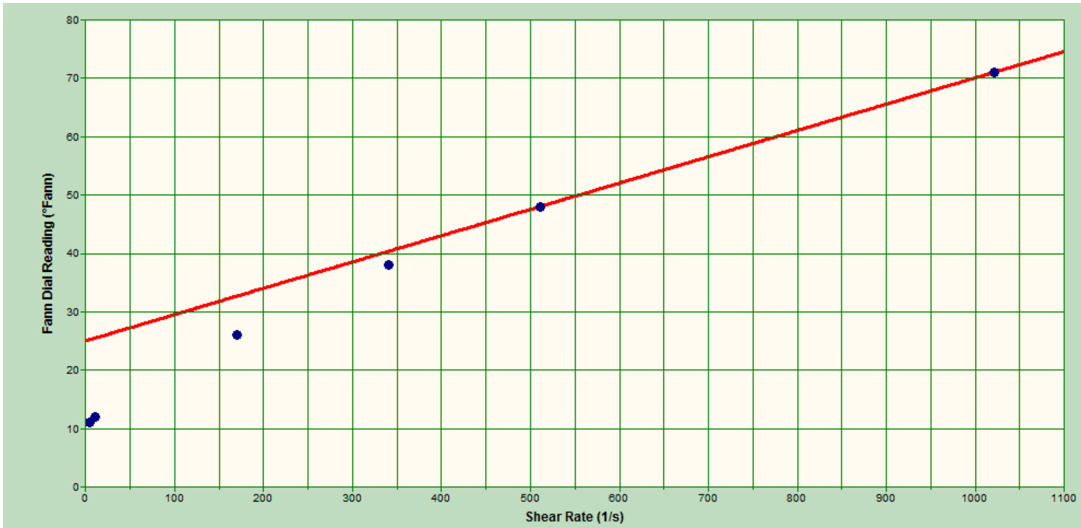
**Software Used: Mudware (Schlumberger Proprietary Software)**



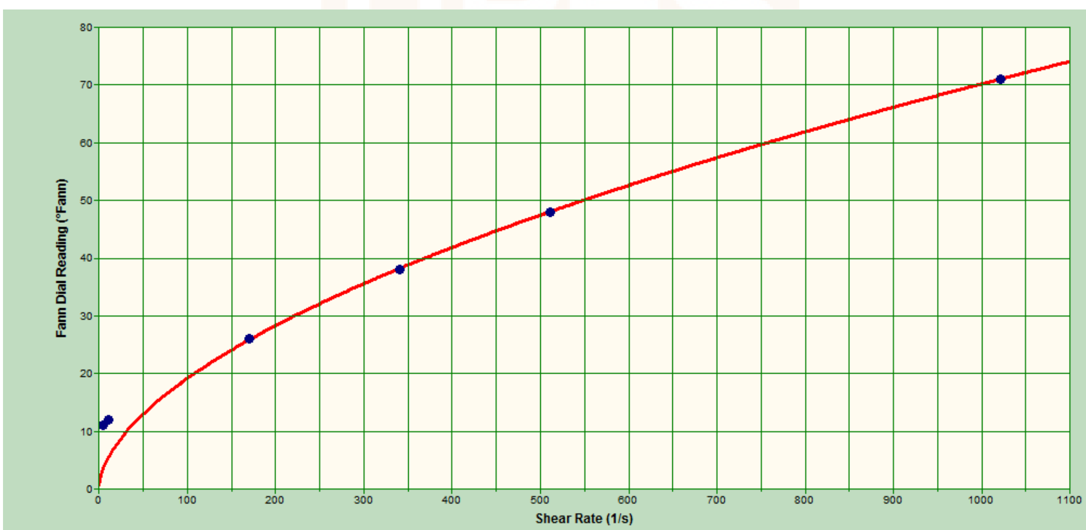

**Graph 1: Viscosity VS Shear Rate: Logarithmic Plot**



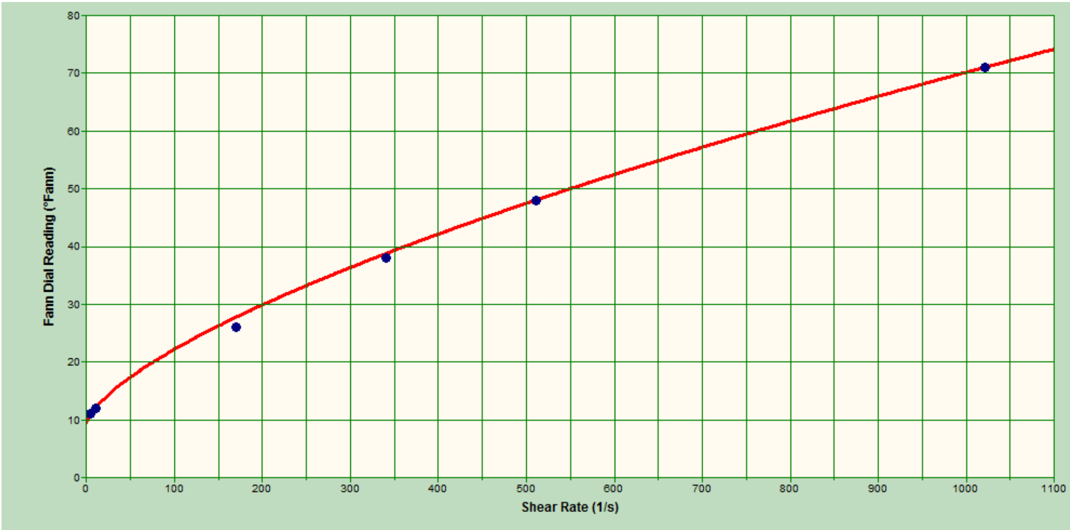

**Graph 2: Viscosity VS Shear Rate: Linear Plot**




**Graph4: Fann Reading VS Shear Rate: Bingham Plastic Model**




**Graph3: Fann Reading VS Shear Rate: Power Law Model**




**Graph5: Fann Reading VS Shear Rate: Herschel Buckley Model**

## 2. DEMONSTRATION:

- Two shale cutting samples from Gujarat were taken and immersed in two different solutions in a beaker.
- The first contained only water and the other contained prepared KCl Polymer Mud System.
- The samples were kept immersed for 2.5 hours and were analyzed for physical alterations visible.
- Pre and Post demonstration sizes were noted.


**Fig15: Shale sample A weighted before running demonstration**




**Fig16: Shale Sample B weighted before running demonstration**

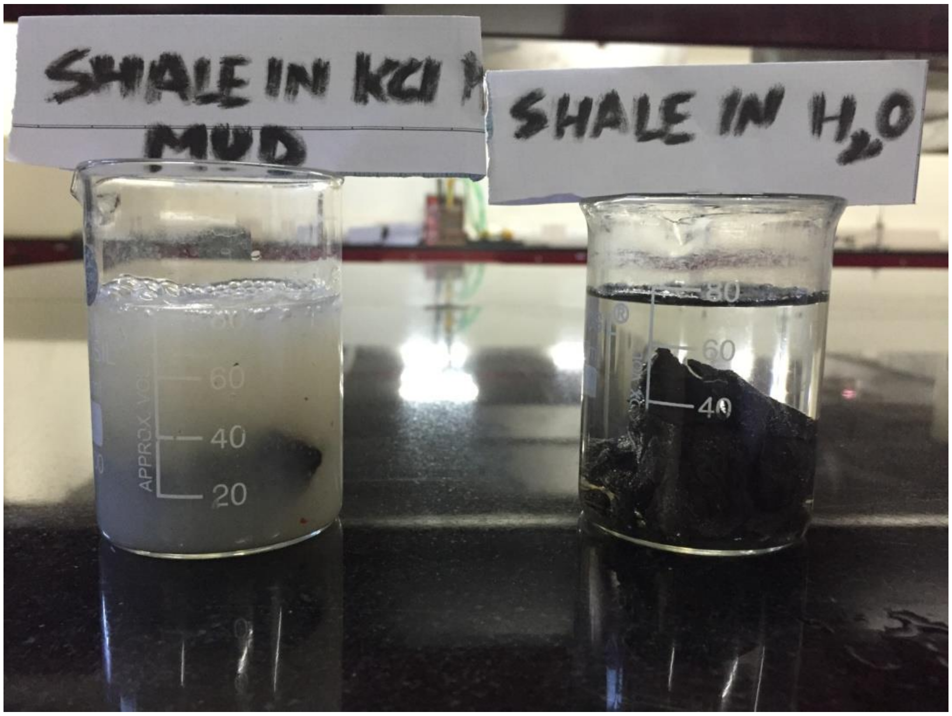



**Fig17: Shale Stability Experimental Analysis Demonstration Setup**

**Beaker 1 (Left) with Shale cutting sample B and Beaker 2 (right) with Shale Cutting Sample A**


**Fig18: Disintegration of Shale due to swelling clearly visible**


**Fig19: Shale Sample A after running demonstration and new total weight**

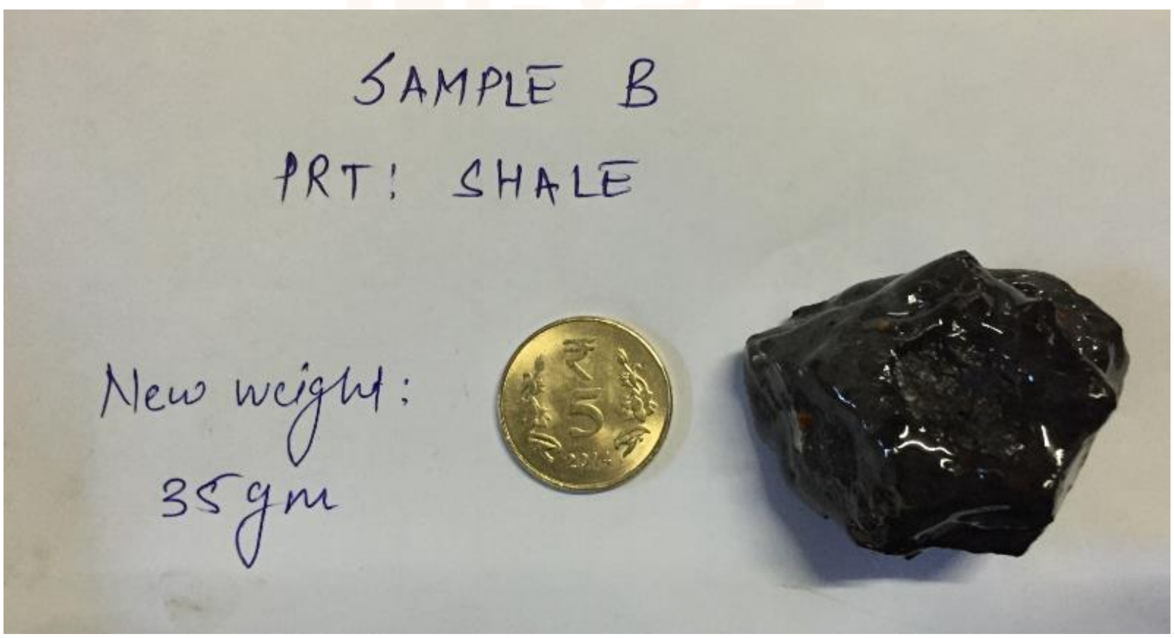



**Fig20: Shale Sample B after running demonstration with New Weight**

**D: ANALYSIS AND INFERENCE**

- Shale sample immersed in Water for 2.5 hours swelled as water entered the lattice voids of the sample causing it to disintegrate and breakdown.
- Shale sample immersed in KCl Polymer Mud for the same duration remained intact after the experiment with only slight rise in its weight.
- K+ ions entered the voids of the lattice and inhibited the entry of water into shale preventing it from swelling.

## EXPERIMENT 2: SALT STABILITY ANALYSIS

**EXPERIMENT DATE:** March.24.2015

**MUD SYSTEM:** Water Based Mud (WBM)

**MUD TYPE:** Salt Saturated Polymer

**TEST SPECIMEN:** Salt

### A: DRILLING FLUID PREPARATION

- Water is the continuous phase in the mud.
- Different additives added in definite proportions within water.
- The fluid is mixed using Hamilton Mixer for different time gaps at different speeds.
- The drilling mud is tested for identifying rheological parameters using Rheometer at different RPM's
- The mud weight is determined using Mud balance and reading noted.

### B: MECHANISM

Saturated saltwater systems are designed to prevent the enlargement of the wellbore while drilling salt sections. This enlargement results from the salt in the wellbore dissolving into the "unsaturated salt" water phase of the drilling fluid. Saturation is achieved by adding salt (sodium chloride) to the mud system until the saturation point is reached. Saturation is about 190,000 mg/L chlorides, depending on temperature. The saturated salt doesn't allow further more salt to dissolve, hence preventing the mobile salt formations to enter into the system and stabilizes the wellbore.



### C: EXPERIMENTAL RUN

1. **FLUID PROPERTIES:**

**MUD FORMULATION**

| S.NO | MUD CONSTITUENT | CONCENTRATION (ppb/gram) | FUNCTION |
|---|---|---|---|
| 1. | Water | 292 | Continuous Phase |
| 2. | Caustic Soda | 0.25 | pH Control |
| 3. | Soda Ash | 0.25 | Treat Calcium/Magnesium |
| 4. | Barite | 11 | Weighting Agent |
| 5. | Sodium Chloride | 110 | Shale Inhibitor |
| 6. | Starch | 6 | Fluid Loss Control Agent |
| 7. | Xanthan Gum | 1.5 | Viscosifier |

Table5: Mud Formulations: Salt Saturated Mud

## EXPERIMENTAL READINGS

- **Mud Density (ppg):** 10
- **Rheometer Readings:**

| S.No | RPM | Reading |
|---|---|---|
| **1.** | R600 | 45 |
| **2.** | R300 | 34 |
| **3.** | R200 | 27 |
| **4.** | R100 | 19 |
| **5.** | R6 | 10 |
| **6.** | R3 | 09 |

**Table6: Rheometer Readings- Salt Saturated Mud**



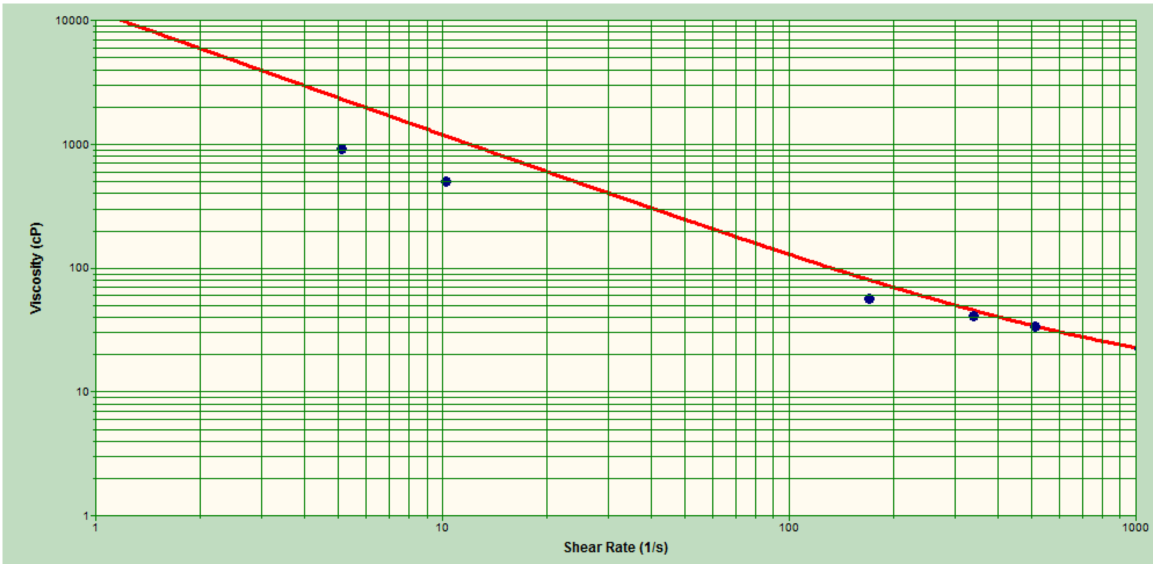
- **Parameters Calculated:**

| S.No | Mud Parameters | Calculated Values |
|---|---|---|
| **1.** | Plastic Viscosity, cp | 11 |
| **2.** | Yield Point, lb/100ft2 | 23 |
| **3.** | Gels, 10sec, lb/100ft2 | 08 |
| **4.** | Gels, 10 min, lb/100ft2 | 09 |
| **5.** | Gels, 30min, lb/100ft2 | 11 |

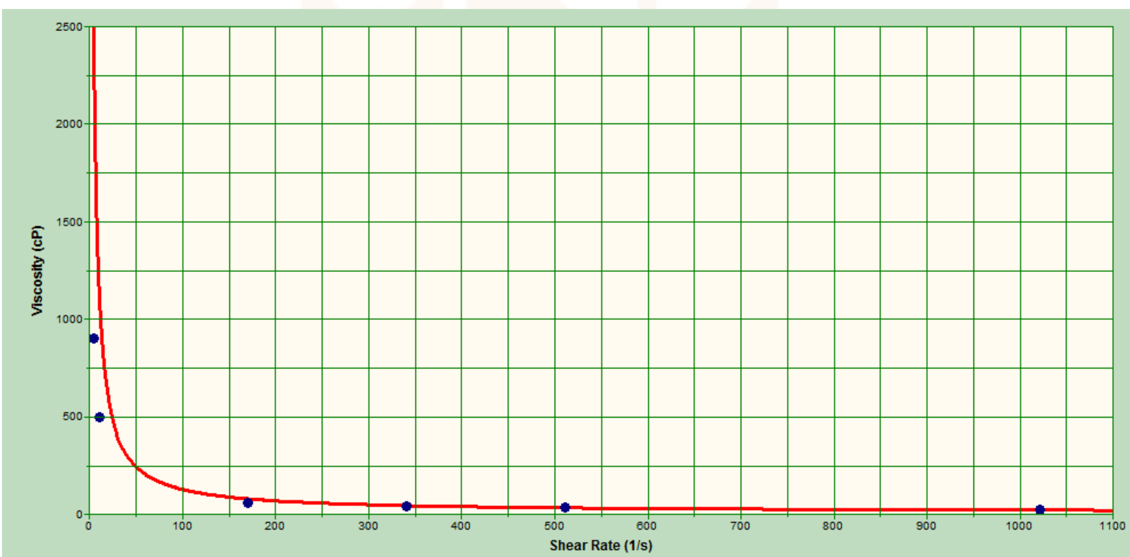
Table7: Mud Parameters- Salt Saturated Mud

**GRAPHS: Salt Saturated Mud System**

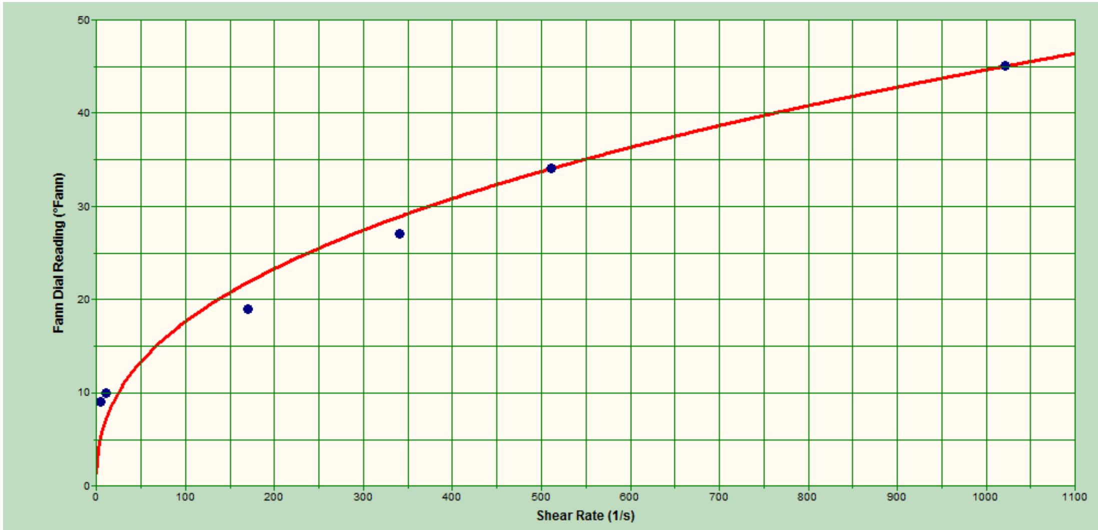
**Software Used: Mudware (Schlumberger Proprietary Software)**



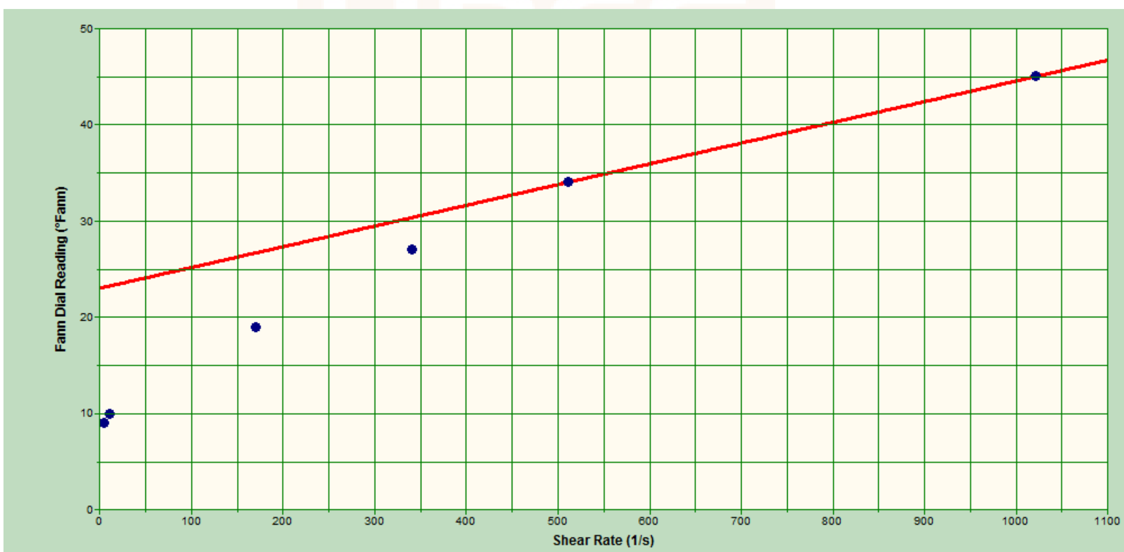

**Graph6: Viscosity VS Shear Rate: Logarithmic Plot**



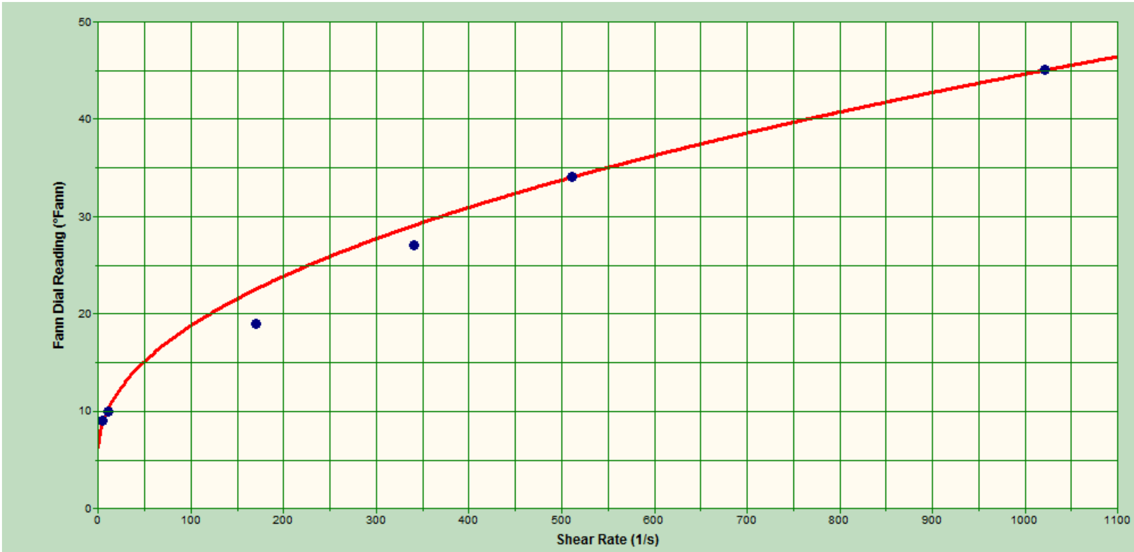

**Graph7: Viscosity VS Shear Rate: Linear Plot**




**Graph8: Fann Reading VS Shear Rate: Power Law Model**




**Graph9: Fann Reading VS Shear Rate: Bingham Plastic Model**




**Graph10: Fann Reading VS Shear Rate; Herschel Bulkley Model**

## 2. DEMONSTRATION:

- A glass container is taken and filled with salt to form lithological unit replica.
- A hollow cylindrical pipe is inserted acting as a drill pipe to act as conduit for injecting prepared mud sample.
- The salt saturated polymer mud is injected through the pipe, while the pipe is being removed with rotary action slowly.
- The mud slowly settles into the well-bore now and the results are analyzed and noted further.

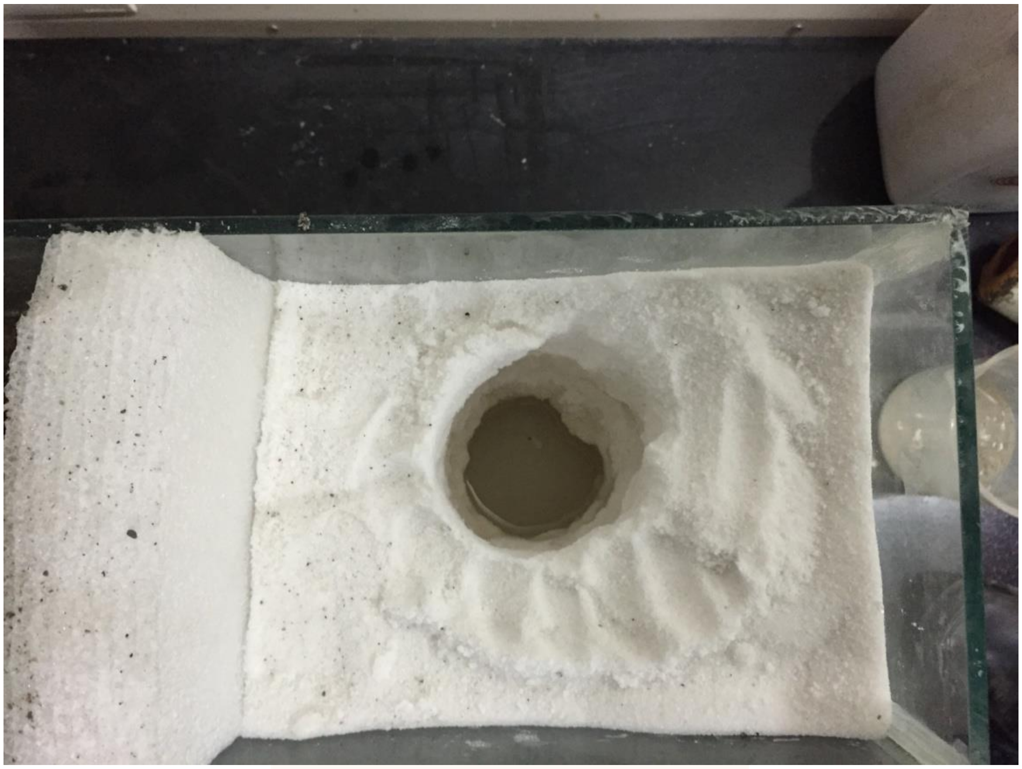


**Fig21: Salt Stability Analysis Demonstration Setup**

**Fig22: Stable Gauge after injecting Salt Saturated Polymer Mud**

## EXPERIMENT 3: SAND STABILITY ANALYSIS

**EXPERIMENT DATE**: April.10.2015

**MUD SYSTEM:** Water Based Mud (WBM)

**MUD TYPE:** Bentonite-Gel Polymer Mud

**TEST SPECIMEN:** Grey Sand (Unconsolidated)

### A: DRILLING FLUID PREPARATION

- Water is the continuous phase in the mud.
- Different additives added in definite proportions within water.
- The fluid is mixed using Hamilton Mixer for different time gaps at different speeds.
- The drilling mud is tested for identifying rheological parameters using Rheometer at different RPM's
- The mud weight is determined using Mud balance and reading noted.

### B: MECHANISM

### C: EXPERIMENTAL RUN:

#### 1. FLUID PROPERTIES:



**MUD FORMULATION**

| S.NO | MUD CONSTITUENT | CONCENTRATION (ppb/gram) | FUNCTION |
|---|---|---|---|
| **1.** | Water | 344 | Continuous Phase |
| **2.** | Caustic Soda | 0.25 | pH Control |
| **3.** | Soda Ash | 0.25 | Treat Calcium/Magnesium |
| **4.** | Bentonite | 28 | Viscosifier |

Table8: Mud Formulation- Bentonite-Gel Mud

## EXPERIMENTAL READINGS

- **Mud Density (ppg):** 8.5
- **Rheometer Readings:**

| S.No | RPM | Reading |
|---|---|---|
| **1.** | R600 | 43 |
| **2.** | R300 | 33 |
| **3.** | R200 | 30 |
| **4.** | R100 | 25 |
| **5.** | R6 | 18 |
| **6.** | R3 | 13 |

Table9: Rheometer Readings- Bentonite-Gel Mud

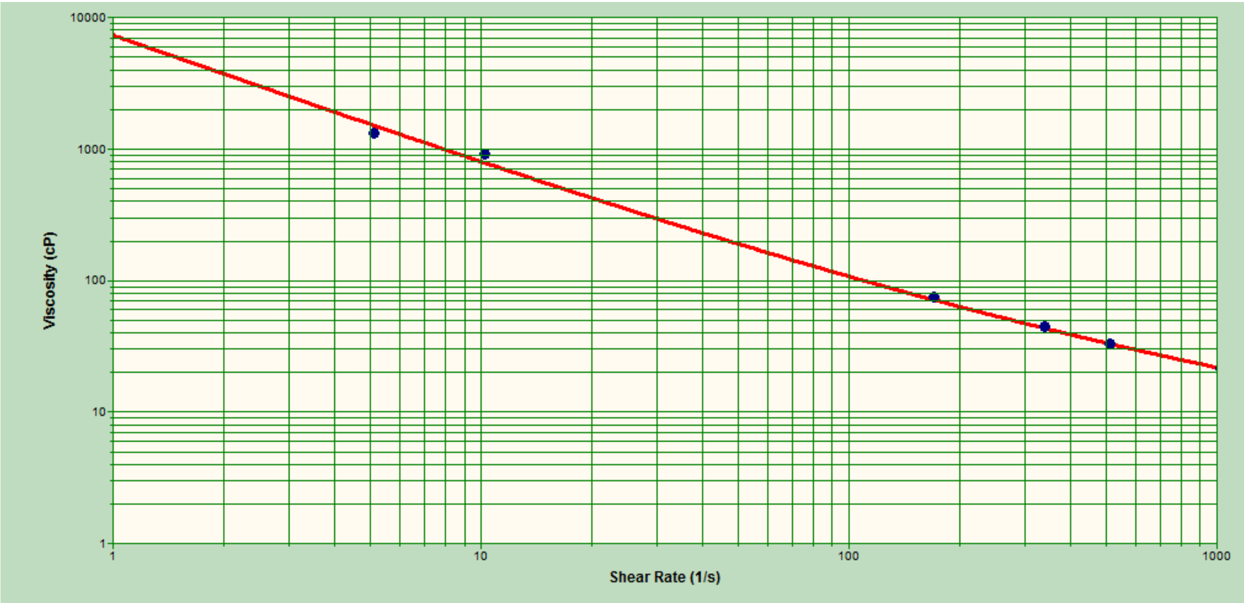


- **Parameters Calculated:**

| S.No | Mud Parameters | Calculated Values |
|---|---|---|
| **1.** | Plastic Viscosity, cp | 10 |
| **2.** | Yield Point, lb/100ft2 | 23 |
| **3.** | Gels, 10sec, lb/100ft2 | 14 |
| **4.** | Gels, 10 min, lb/100ft2 | 18 |
| **5.** | Gels, 30min, lb/100ft2 | 24 |

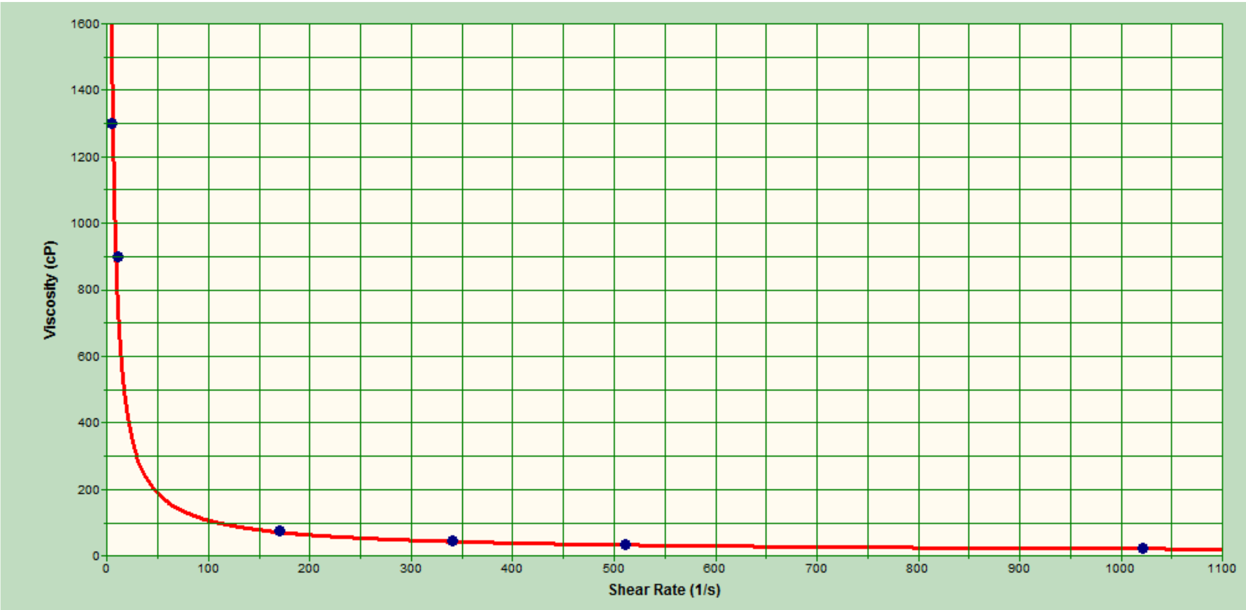
Table10: Mud Parameters- Bentonite-Gel Mud

**GRAPHS: Bentonite-Gel Polymer Mud System**

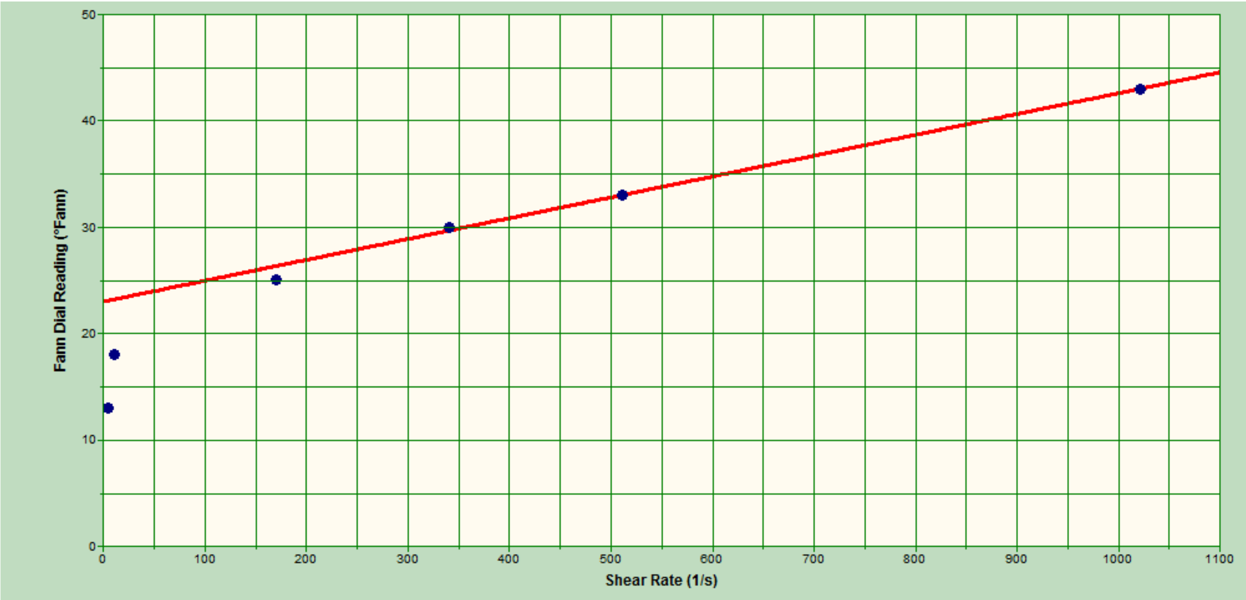



**Graph11: Viscosity VS Shear Rate :Logarithmic Plot**

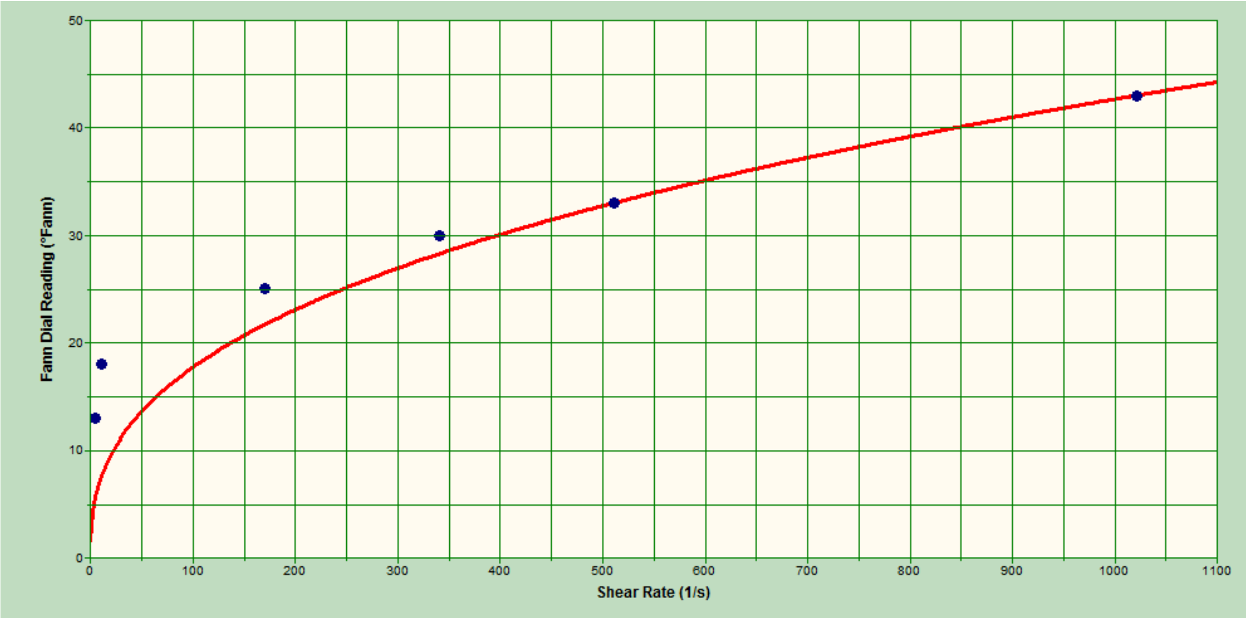




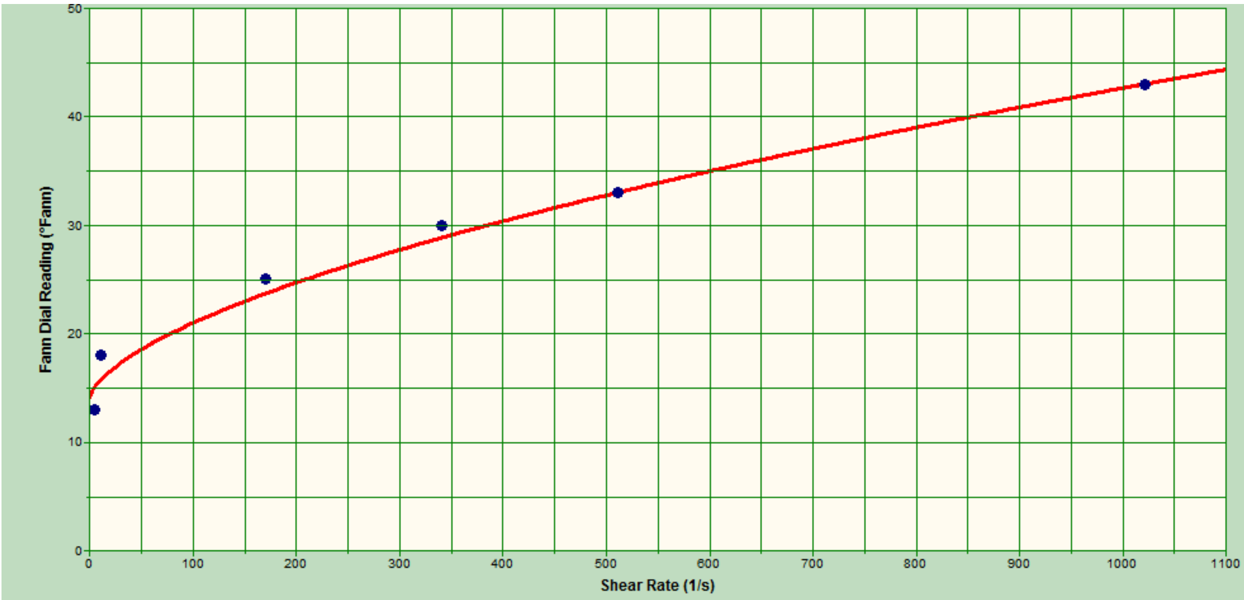

**Graph12: Viscosity VS Shear Rate: Linear Curve**




**Graph13: Fann Viscometer Reading VS Shear Rate: Bingham Plastic Model**




**Graph14: Fann Viscometer Reading VS Shear Rate: Power Law Model**




**Graph15: Fann Viscometer Reading VS Shear Rate: Herschel Bulkley Model**

## 2. DEMONSTRATION:

- A glass container is taken and filled with unconsolidated grey sand to form lithological unit replica.
- A hollow cylindrical pipe is inserted acting as a drill pipe to act as conduit for injecting prepared mud sample.
- The Bentonite gel polymer mud is injected through the pipe, while the pipe is being removed with rotary action slowly.
- The mud slowly settles into the well-bore now and the results are analyzed and noted further.

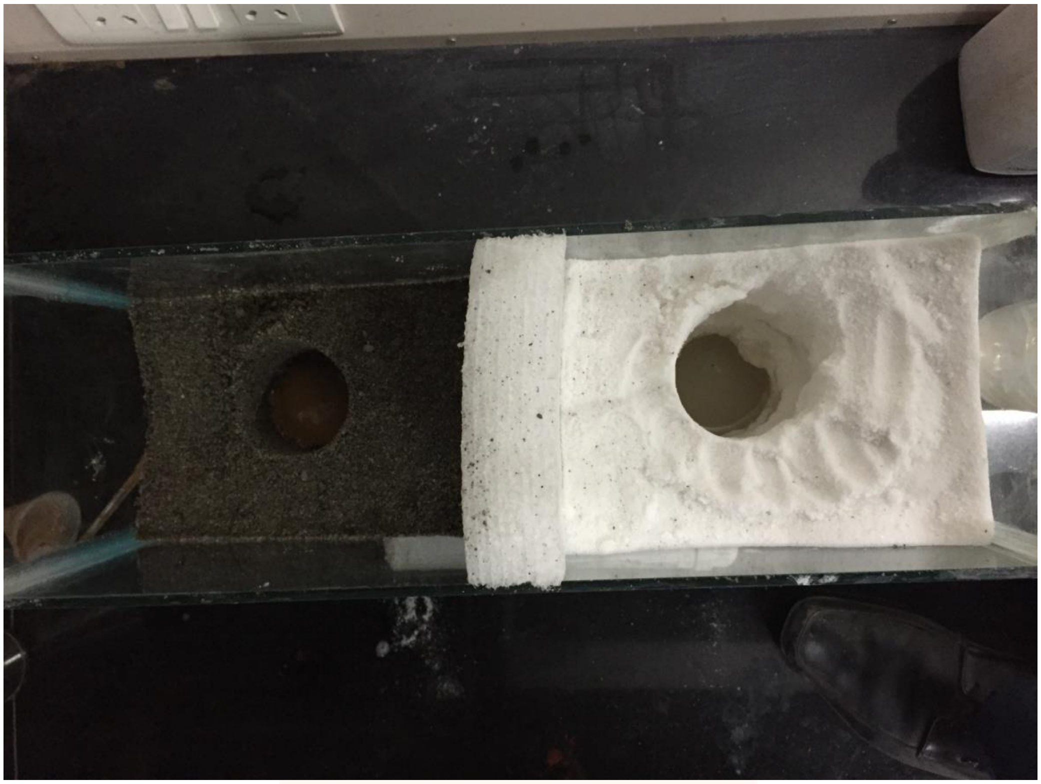


**Fig23: Sand Stability Analysis Demonstration Model**

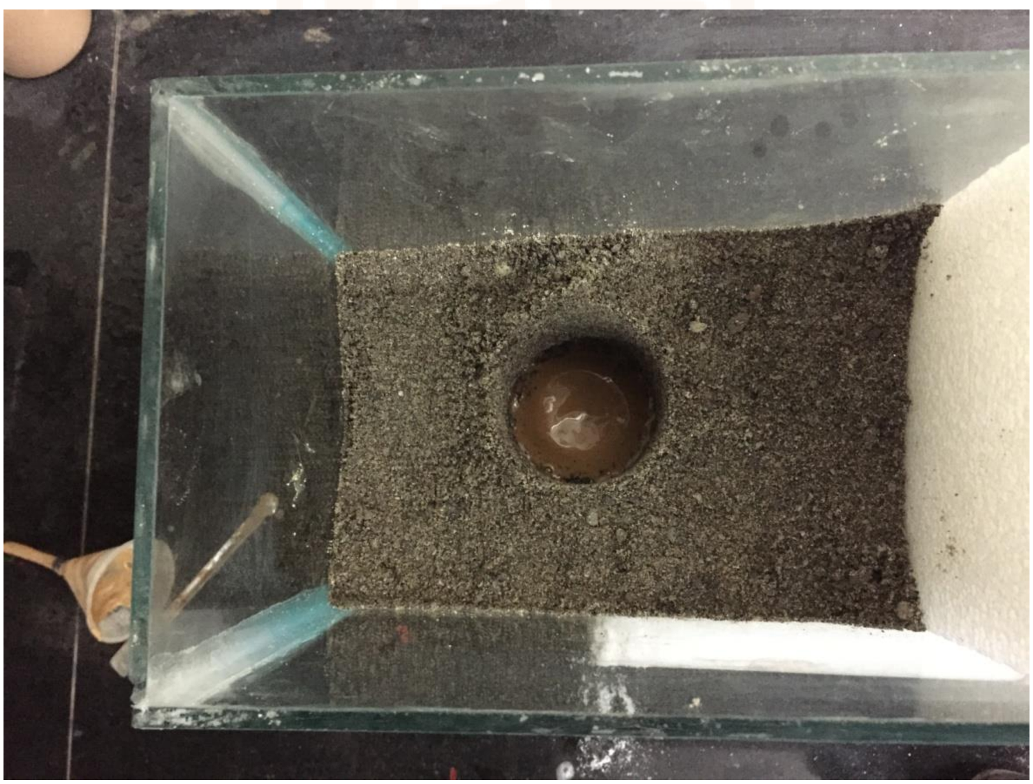


**Fig24: Stable Gauge formed using Bentonite-Gel Polymer Mud**

## D: ANALYSIS AND INFERENCE

- The Bentonite mud prepared is hydrated for minimum 2 hours after preparation
- Bentonite-Gel Polymer stabilized the unconsolidated sand wellbore and prevented it to collapse

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# ANNEXURES

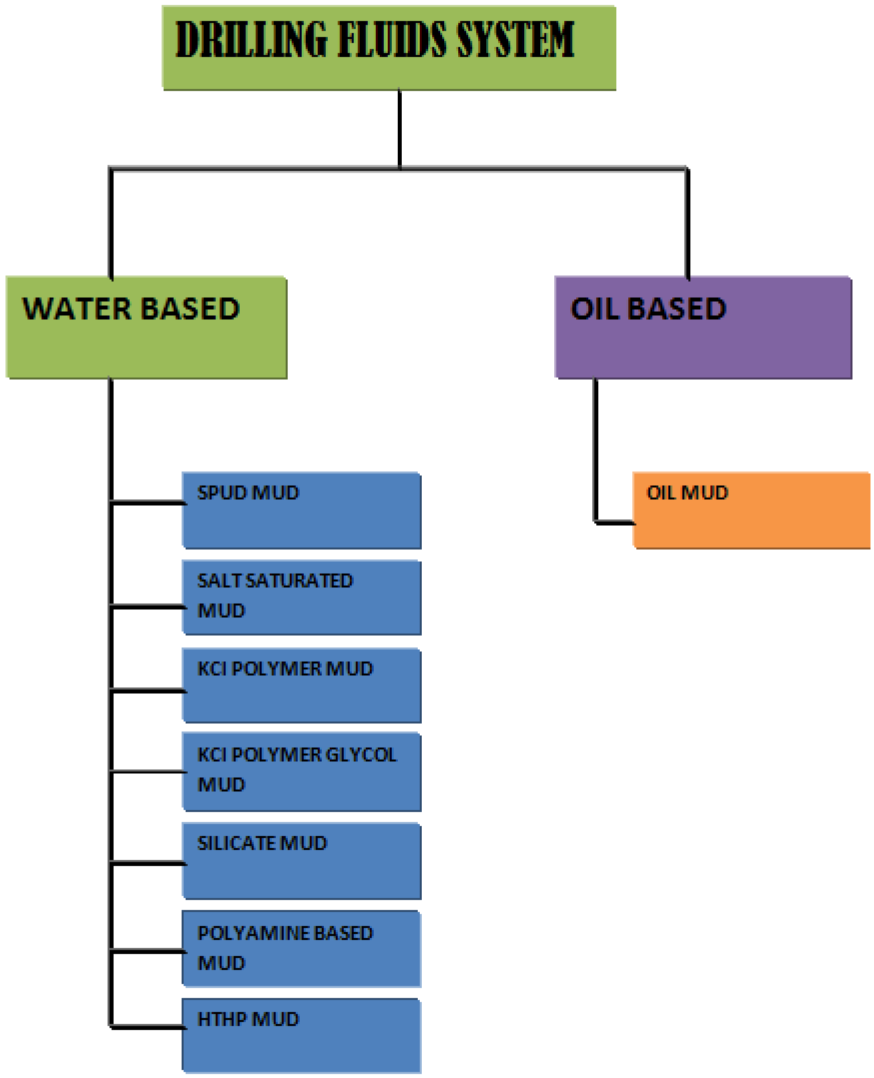


## COMPOSITION OF DRILLING FLUIDS

a. Continuous Phase – Liquid/gas

b. Dissolved/ Dispersed Chemicals/Suspended Particles

**CLASSIFICATION OF DRILLING FLUIDS**




**Water Base Fluids (WBM)**

**Polymer Fluids:**

- Muds incorporating long chain, high molecular weight polymers are utilized to either encapsulate drill solids to prevent dispersion and coat shales for inhibition.
- Various types of polymers are available,
  a. Acrylamide
  b. Cellulose
  c. Natural gum based products
- Frequently inhibiting salts such as KCl or NaCl used for greater stability
- Minimum amount of bentonite
- Temp. limits < 150deg. C

**Low Solid Fluids:**

- Amount (volume) and type of solids are controlled
- Total solids should not range higher than about 6% to 10% by volume.
- Polymer additive used as viscosifier or bentonite extender
- Improves ROP

**Oil Base Fluids**

- Used for applications where fluid stability and inhibition are necessary such as;
  a. High temperature Wells
  b. Deep holes
  c. Slicking and hole stabilizing problems
- **OBM**: formulated with oil as continuous phase and often used as coring fluids
- No additional water or brine is added
- Special OBM additives includes;
  a. Emulsifiers and wetting agents (fatty acids and amine derivatives)
  b. High molecular wt. soaps
  c. Surfactants
  d. Amine treated OM
  e. Organic clays
- **Invert Emulsion Muds**: water in oil emulsions typically with calcium chloride brine as the emulsified phase and oil as continuous phase

**Synthetic Oil Based Muds (SOBM)**

- Designed to mirror OBM performance without environmental hazards
- Primarily esters, ethers, poly alpha olefins, isomerised alpha olefins
- Environmental friendly, canbe discharged offshore , non sheening and biodegradable



**AIR, MIST, FOAM, GAS SYSTEM**

(Reduced DF weight category)

- **Dry Air Drilling:** injecting dry air or gas into wellbore at rates capable of achieving annular velocities that will remove cutting
- **Mist Drilling:** injecting foaming agent into the air stream which mixes with produced water and coats the cutting which prevents mud rings allowing drill solids to be removed
- **Foam:** uses surfactants and possibly clays or polymers to form a high carrying capacity foam
- **Aerated Fluids:** mud with injected air (reduces hydrostatic head) to remove drilled solids from wellbore.

**MONITORING OF DRILLING FLUIDS**

1. **Specific Gravity**: using mud balance
2. **Viscosity**: Plastic Viscosity (PV) – frictional resistance in fluid in motion
   Yield Point (YP)- electrical resistance in the fluid motion
   Measured by marsh funnel and Fann VG meter)

3. **Sand Content:**
   a. Abrasive and harmful to equipments
   b. High sand content contributes to undesired thick filter cake; raise unwanted sp. Gravity, lost circulation, formation invasion etc.
4. **Filter Cake**
5. **Solid Contents** : Removal equipments;
   a. Shale Shaker
   b. D-Sander
   c. D-Silter
   d. Mud Cleaners
   e. Centrifuge

6. **Salinity** (Potassium Ion/ PHPA Estimation )
   - Precipitate method – filtrate
   - Salinity- Potassium chromate and silver nitrate
   - Potassium Ion- sodium perchlorate
   - PHPA- stannin chloride

**MUD CHEMICALS:**

1. **Water :**
   - Highest surface tension, dielectric constant , heat of fusion , heat of vaporization
   - Dissociation of salts , acids and bases in water
   - Reaction between water and clay surfaces and the effect of electrolytes dissolved in water on the clay-water interactions are responsible for drilling mud properties

2. **Aluminium Stearate:**
   - White powder
   - Used in de-foamer i.e. reduces foaming action
   - Insoluble in water
   - Partially soluble in diesel and hence treated by making solution in diesel (2.5%)

3. **Bactericide:**
   - Controls bio degradation of natural organic additives in polymer mud
4. **Bentonite:**
   - Minimum 85% montmorillonite
   - Sp. Gravity 2.45-2.55
   - Sodium Bentonite or Calcium Bentonite depending on dominant exchangeable cation
   - High yield and low yield bentonite
   - Functions of bentonite in DF :
     a. Reduce water seepage or filtration in to permeable formation
     b. Increase hole cleaning capacity
     c. Forms thin filter cake of low permeability
     d. Promotes hole stability
     e. Avoid loss of circulation

5. **Barite:**

- Grey powder
- Sp. Gravity 4.2-4.25
- Virtually insoluble in water and does not react with other mud component
- $CaSO_4$ (gypsum) present as impurity causes contamination in fresh water muds
- Used to increase sp. Gravity of mud to control formation pressure
- Other weighing material are hematite and galena

**6. Caustic Soda (NaOH)**

- Increase pH of mud
- Sp. Gravity 2.13
- Added to mud slowly to avoid sudden increase in pH that results in decomposition of polymers and unwanted sudden rise of viscosity in bentonite mud.

**7. Caustic Potash (KOH)**

- Increase pH of Potassium treated mud and stabilizes lignite
- Sp. Gravity 2.04

**8. Sodium Carboxymethyl Cellulose (CMC)**

- Most widely used organic polymers are semi synthetic produced by chemical modification of cellulose
- Water dispersible, colorless, odorless, non-toxic
- CMC- LVG
  CMC-HVG
- Isotropic polymer adsorbed on clays
- Increases viscosity and reduce filtration loss
- Thermal degradation starts as temp. approaches 150deg. C

**9. Common Salt**

- Used to prepare brine during activation of well
- Used for inhibition
- Sp. Gravity- 1.20

**10. Corrosion Inhibitor**

- KCl mud and brines

**11. Calcium Carbonate (MCC)**

- Fine powdered, practically insoluble in water
- Sp. Gravity 2.6-2.8
- Used as bridging agent and weighing material in NDDF

**12. Drilling Detergent**

- To clean bit / stabilizers/ tool joints during drilling of clay and increase ROP

**13. E P LUBE**

- Used as lubricant at deeper depth
- Vegetable oil based lubricant
- Makes a very high slim strength between formation and string surface thus reduces friction

**14. Lignite**

- Mild dispersant
- Acts as thinner
- Increased temperature stability (upto 260deg C)
- Deflocculant: reduces attraction between clay and particles

15. **Limestone**
    - Weighing material
    - Sp. Gravity 2.65
16. **Linseed Oil**
    - Vegetable oil used as lubricant
    - Creates film between formation and string

17. **Mica**
    - Loss Circulation material
    - Form of flakes which plugs the large gaps in the formation in case of mud loss

18. **Poly Anionic Cellulose (PAC)**
    - Limitation of CMC in salt solution led to development of PAC polymer
    - Sp. Gravity 1.5-1.6
    - Thickens salt solution, environmentally acceptable polymer
    - Shale inhibitor
    - Two forms are available;
      a. PAC (LVG) – viscosifier anf filtration control
      b. PAC(RG)- viscosifier, filtration control, has long chain than PAC(LVG)

19. **PHPA**
    - Shale stabilization and inhibition by encapsulation of cutting in mud
    - Long chain polymer

20. **POLYOL ( Poly glycol)**
    - Shale stabilization and lubrication
    - Clouding at temperature higher than 78deg C
    - Plugs formation pores and prevent invasion and imparts BHS



21. **Potassium Chloride:**
    - Shale stabilization and brine preparation
    - Replaces Na ion in bentonite with Potassium ion thus preventing swelling of clays
22. **Resinated Lignite**
    - Dispersant and used for filtration control and temperature stabilization of rheology
    - Stable upto 160deg C
23. **Sulphonated Asphalt**
    - Shale stabilizers
    - Used in WBM for hole stabilization
    - Adsorbed on shale to plug microfractures

24. **Soda Ash**
    - Removal of calcium from muds and make up water
    - Sp. Gravity 2.53
    - Increase pH in mud

25. **Spotting Fluid** : for freeing stuck pipe by reducing IFT between filter cake and string eventually cracking the cake

**RHEOLOGY:**

| **CONVERSION FACTOR:** |
|---|
| **Shear Rate = RPM * 1.703** |

| CONVERSION FACTOR: |
| --- |
| Shear Stress = VG Reading * 1.0678 |

**FLUID FLOW MODELS:**

- **Bingham Plastic Model**
- **Power Law Model**
- **Herschel- Buckley Model (Modified Power Law)**
- **Casson Robertson –Stiff Model**

**A. BINGHAM PLASTIC MODEL**

These fluids require a finite shear stress, $\tau_y$; below that, they will not flow. Above this finite shear stress, referred to as yield point, the shear rate is linear with shear stress, just like a Newtonian fluid. Bingham fluids behave like a solid until the applied pressure is high enough to break the sheer stress.

Mathematical Expression:

- **F= YP+PV(R/300)**
  Where;
  F= dial radius at speed R
- **PV = $R_{600}$ – $R_{300}$**
- Mud additives count to Plastic Viscosity especially wetting agents.
- Lesser the size, more will be surface area, more will be the friction
- Increase in PV, leads to increase in Mud weight, causing differential sticking
- Sand control equipments , like centrifuge cuts around half the value of PV
- Factors affecting Yield Point (YP);
  a. Type of formation (carbonates, formation salts )
  b. Reactions of clay ( clay carry residual charges that affects YP)
  c. Overtreatment of mud chemicals
  d. Contaminants like acid gases such as $H_2S$, $CO_2$ etc.
- Yield Point can be treated by addition of chemicals; more clay leads to more YP
  a. Dilution Method
  b. Addition of dispersants or thinners
- YP increases, Gel value increases

**B. POWER LAW MODEL**

These fluids exhibit a linear relationship between shear stress and shear rate when plotted on a log-log paper.

Mathematical Expression:
**Shear Rate = K (Shear Stress) $^n$**
Where; K= Consistency Factor
n= Fluid Flow Index
Depending on the value of "n," three different types of flow profiles and fluid behavior exist: 1. n < 1: The fluid is shear-thinning, non-Newtonian.
2. n = 1: The fluid is Newtonian.
3. n > 1: The fluid is dilatants, shear thickening (drilling fluids are not in this category).

**A fluid's hole-cleaning and suspension effectiveness can be improved by increasing the "K" value.**

**$V_{G\ (Reading)} * 1.0678 = K\ (V_{G\ (RPM)} * 1.703)^{n}$**
n= shear thinning ability of mud (thixotropic property of fluid)

- $n_a$ (annulus) / $n_p$ (pipe)
- $n_p = 3.321 \log Ø_{600} / \log Ø_{300}$
- $n_a = 0.657 * \log Ø_{100} / Ø_6$
- more the value of n, more will be shear thinning, more will be k
- $K_p = 5.11 * R_{600}/1022^{np}$
- $K_a = 5.11 * R_3/ 511^{na}$
- n<1 (always )

## C. MODIFIED POWER LAW

Also known as Herschel-Buckley fluids, these fluids require a finite shear stress, $\tau_y$, below which they will not flow. Above this finite shear stress, referred to as yield point, the shear rate is related to the shear stress through a power-law type relationship.

Mathematical Expression:
**Shear Rate = Yield Stress + K (Shear Stress)$^{n}$**
Where Yield Stress is the R3 Reading

- The yield stress has been accepted to be the value for the 3-RPM reading or initial gel on the VG meter.
- Converting the equations to accept VG meter data gives the equations for "n" and "K."

**$n = \log (\Theta_2 - \Theta_0) - \log (\Theta_1 - \Theta_0) / \log \omega_2 - \log \omega_1$**

**$k = \Theta_1 - \Theta_0 / \omega_1^{n}$**

Where:
n = Power Law index or exponent
K = Power Law consistency index or fluid index (dyne sec–n/cm2)
Q1 = Mud viscometer reading at lower shear rate
Q2 = Mud viscometer reading at higher shear rate
Q0 = Zero gel or 3-RPM reading
w1 = Mud viscometer (RPM) at lower shear rate
w2 = Mud viscometer

**ECD CALCULATIONS:**

*Step 1* — **Draw Hole Geometry**

*Step 2* —

$$V_a = \frac{0.408(Q)}{(D_2)^2 - (D_1)^2}$$

*Step 3.A* —

$$n_a = 0.5\log\left(\frac{\theta_{300}}{\theta_3}\right)$$

*Step 3.B* —

$$K_a = \frac{5.11(\theta_{300})}{511^{n_a}}$$

*Step 4* —

$$\mu_{ea} = 100K_a\left[\frac{144V_a}{D_2 - D_1}\right]^{n_a - 1}$$

*Step 5* —

$$Re_a = \frac{928V_a(D_2 - D_1)\rho}{\mu_{ea}\left[\frac{2n_a + 1}{3n_a}\right]^{n_a}}$$

*Step 6.A* —

$$Re_L = 3470 - 1370n_a$$

*Step 6.B* —

$$Re_T = 4270 - 1370n_a$$

*Step 7*

**Laminar Flow**

$$f_a = \frac{24}{Re_a}$$

**Transitional Flow**

$$f_a = \left[\frac{Re_a - Re_L}{800}\right]\left[\frac{(\log n_a + 3.93) \div 50}{Re_L^{([1.75 - \log n_a] \div 7)}} - \frac{24}{Re_L}\right]$$

**Turbulent Flow**

$$f_a = \frac{(\log n_a + 3.93) \div 50}{Re_a^{([1.75 - \log n_a] \div 7)}}$$

*Step 8* —

$$P_a = \frac{(f_a)V_a^2(\rho)}{25.81(D_2 - D_1)}(L)$$

*Step 9* — *Repeat Steps 2 - 8 for each Annular Geometry*

*Step 10* —

$$P_{aT} = \Sigma P_a$$

*Step 11* —

$$ECD = \frac{P_{aT}}{(0.052)(TVD)} + \rho$$

**SWAB AND SURGE CALCULATION**

**Method**

*Step 1* — Method 1: $V_{pm} = \frac{60 L_s}{t}$ — Method 2: $V_{pm} = \frac{60 L_j}{t}$

*Step 2* — $$V_m = \left[0.45 + \frac{D_1^2}{D_2^2 - D_1^2}\right] V_{pm}$$

*Step 3.A* — $$n_a = 0.5\log\left(\frac{\theta_{300}}{\theta_3}\right)$$

*Step 3.B* — $$K_a = \frac{5.11(\theta_{300})}{511^{n_a}}$$

*Step 4* — $$\mu_{ea} = 100 K_a \left[\frac{144 V_m}{D_2 - D_1}\right]^{n_a - 1}$$

*Step 5* — $$Re_a = \frac{928 V_m (D_2 - D_1)\rho}{\mu_{ea}\left[\frac{2n_a + 1}{3n_a}\right]^{n_a}}$$

*Step 6.A* — $$Re_L = 3470 - 1370 n_a$$

*Step 6.B* — $$Re_T = 4270 - 1370 n_a$$

*Step 7*

**Laminar Flow**

$$f_a = \frac{24}{Re_a}$$

**Turbulent Flow**

$$f_a = \frac{(\log n_a + 3.93) \div 50}{Re_a^{([1.75 - \log n_a] \div 7)}}$$

**Transitional Flow**

$$f_a = \left[\frac{Re_a - Re_L}{800}\right]\left[\frac{(\log n_a + 3.93) \div 50}{Re_L^{([1.75 - \log n_a] \div 7)}} - \frac{24}{Re_L}\right]$$

*Step 8* — $$P_a = \frac{(f_a) V_m^2 (\rho)}{25.81(D_2 - D_1)}(L)$$

*Step 9* — *Repeat Steps 2 - 8 for each Annular Geometry*

*Step 10* — $$P_{aT} = \Sigma P_a$$

**Surge Pressure EMW**

*Step 11.A* — $$EMW = \frac{P_{aT}}{(0.052)(TVD)} + \rho$$

**Swab Pressure EMW**

$$EMW = \rho - \frac{P_{aT}}{(0.052)(TVD)}$$ — *Step 11.B*

**BIT HYDRAULICS**

**Start**

*Step 1* —
$$\Delta P_b = \frac{156.5(Q^2)(MW)}{\left[(J_1)^2 + (J_2)^2 + (J_3)^2\right]^2}$$

*Step 2* —
$$HHP_b = \frac{Q \times \Delta P_b}{1714}$$

*Step 3* —
$$HHP_b/\text{in}^2 = \frac{HHP_b \times 1.27}{(Bit\ size)^2}$$

*Step 4* —
$$V_n = \frac{417.2 \times Q}{(J_1)^2 + (J_2)^2 + (J_3)^2}$$

*Step 5* —
$$I.F. = \frac{V_n(Q)(MW)}{1930}$$

*Step 6* —
$$I.F./\text{in}^2 = \frac{I.F. \times 1.27}{(Bit\ size)^2}$$

*Step 7* —
$$\%PSI_b = \frac{\Delta P_b}{Surface\ PSI} \times 100$$

*Step 8* —
$$System\ HHP = \frac{Surface\ PSI \times Q}{1714}$$