Dissertation on

"Study on HPHT Drilling"

Dissertation submitted to College of Engineering Studies for the partial fulfillment of the degree of

M.Tech (Petroleum Exploration)

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Declaration

I hereby declare that this project titled "**Study on HPHT Drilling**" submitted by me to University of Petroleum & Energy studies for the partial fulfillment of requirements of M.Tech programme is a bonafide work carried out by me under the guidance of **Dr. Avinish Kumar (DGM (Chemistry) & Mr. Kedareshwarudu (Professor), UPES**

Place: Dehradun

Date: 04-05-2012

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BONAFIDE CERTIFICATE

This is to certify that **Mr. Prasanth Parasseril Jose** ,Enrollment no.R770209014, a student of **University of Petroleum and Energy Studies, Bidholi , Dehradun** pursuing **M.Tech (Petroleum Exploration)**, has successfully completed his Dissertation Report as a part of his curriculum. The project report entitled **"Study on HPHT Drilling"** submitted by the student to the undersigned is an authentic record of his original work, which he has carried out under my supervision and guidance.

I wish him all the best.

Dr. Kedareshwarudu
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I wish him all the best.

4th May, 2012

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INTRODUCTION

Worldwide demand for energy continues to increase and is projected to average 2% per year out of 2030. Demand is widespread geographically but the most rapid growth is projected for non-OECD (Organization for Economic Cooperation and Development) nations averaging 3.7% per year. Providing adequate supply is driving the industry to explore areas previously unexplored. A subset of this activity is HPHT Drilling. HPHT drilling is not rigorously pursued during times of price uncertainty or low commodity pricing due to relative high lifting cost. The resurgence in HPHT drilling stretches globally and encompasses areas such as deep Gulf of Mexico Continental Shelf, Northern India, Saudi Arabia and Brunei. Historical HPHT basins such as Indonesia, Thailand and Northern Malaysia have also seen a selective increase in HPHT activity.

Several factors have combined to make deep oil and gas increasingly attractive worldwide:

- Abundant infrastructure in the way of platforms, producing facilities and pipelines that would allow new productions to flow quickly to market.
- New technology such as 3D seismic and faster computers to locate potential formations.

With increase in growth and development, energy demand is also increasing. All efforts are being made to develop alternate energy sources .However fossil fuel is going to be the top energy source for at-least few decades. Due to this reason, oil companies have been forced to search new hydrocarbon sources in extreme formation environment where temperature may go up to 500°F. and pressure up to 30000 psi.

Drilling of oil and gas wells, bearing high pressure and high temperature is a challenging task. Meticulous planning at every step is required including drilling fluid management .Due to high temperature ,special chemicals are required which can impart good rheology and fluid loss control at elevated temperature, where most of the conventional mud additives fail to give required drilling fluid parameters.

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AIM

To study the properties and characteristics of drilling mud used in HPHT drilling and the apparatus used to prepare the mud and measure the mud properties (mud density, viscosity, pH , weighting material and proper rheology) and how these properties are varied to reduce the challenges in HPHT wells. Case studies of some HPHT wells drilled by ONGC will also be studied.

SCOPE OF PROJECT

The narrow hydraulic window between pore pressure and fracture pressure when operating in HPHT wells requires drilling fluids that deliver minimal frictional pressures loss during pumping and displacement to minimize ECD (equivalent circulating density) and surge/swab effects during tripping. Generally ,oil based drilling fluids exhibit better temperature stability when drilling at high temperature compared to water-based mud .Oil based mud provide better drilling performance by producing low coefficient of friction and hence improved hole stability .Hence designing of a proper drilling fluid with desired properties for HPHT wells due to extreme conditions(high pressure and high temperature) is essential.

How the challenges in HPHT wells including lost circulation, well kicks, blow outs and other mechanical constraints can be reduced by varying the properties and characteristics of drilling fluid used. Since high temperature (greater than 150°C) and high pressure (greater than 10000 psi) is the reservoir condition in HPHT wells, design of proper drilling fluid is essential with necessary properties (mud density, viscosity, pH, weighting material and proper rheology).

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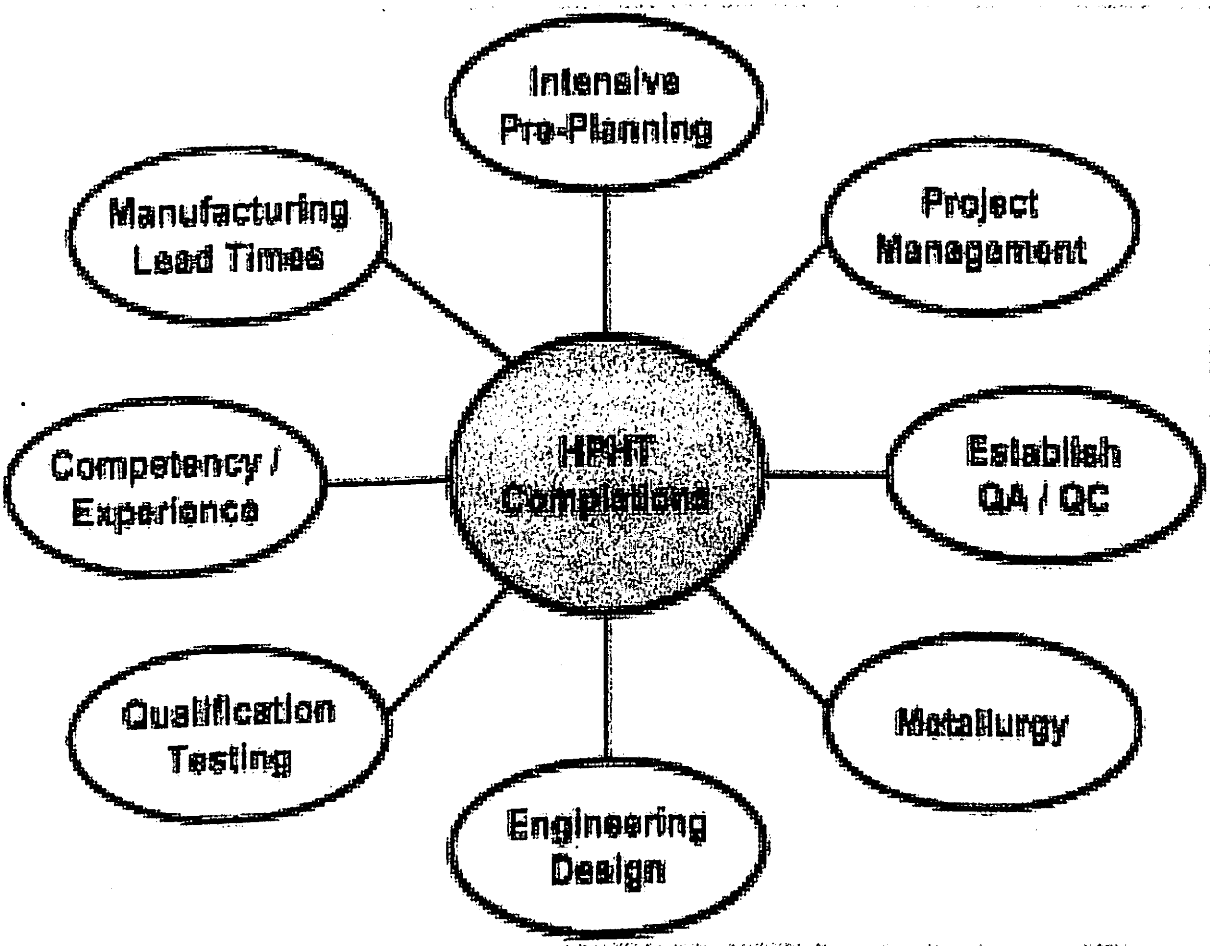

What are HPHT Wells

HPHT wells are defined as where the undisturbed BHT at particular depth is greater than 149^0 C and the maximum anticipated pore pressure 10000 psi or more.

Types of HPHT Wells

- **Normal HPHT wells**: Reservoir pressure up to 15000 psi and temperature up to 350^{0}F(177^{0}C)
- **Extreme HPHT wells**: Reservoir pressure up to 20000 psi and temperature up to 400^{0}F (204^{0}C).

- **Ultra HPHT wells:** Reservoir pressure up to 30000 psi and temperature up to 500^{0}F (260^{0}C).
- **HPHT- hc**: Bottom Hole Temperature more than 260^{0}C and pressure up to 35000 psi

Drilling and Drilling Fluid Challenges in HPHT wells

Developing HPHT prospects can require overcoming formidable drilling challenges. Rigs capable of HPHT drilling are larger due to requirements such as hook load, mud pumps, drill pipe and surface mud capacity. Due to these requirements, these rigs are more expensive .HPHT wells require high density fluid which typically requires high solids loading .High solids loading, resulting in high pressures combined with competency of rock at depth, lead to low penetration depths, extending time on location and added drilled costs. In extreme cases, pressure, temperature and acid gas levels can limit the selection and function of down-hole tools and fluid selection. These limitations can become so severe that MWD/LWD tools become unusable, rendering down-hole annular pressure measurements used for pressure measurement unavailable. This places additional demands on the drilling fluid and temperature/hydraulic model .These models are based on surface inputs and laboratory measured fluid properties under down-hole conditions.

Invert emulsion fluids have been utilized for drilling HPHT wells and the technology for temperatures up to 500°F, but recent HPHT activity presents even harsher environments with estimated Bottom hole temperature (BHT) approaching 600°F.Recognizing the need for fluids with higher temperature stability, we set out to develop products engineered to withstand the extreme BHT conditions of wells beyond 25,000 ft TVD.

The choice of products utilized for a particular drilling project is based on anticipated bottom-hole temperature. Each fluid is engineered to meet specific requirements of the operator. Synthetic, low aromatic/low toxicity base fluids or diesel oil are used as base oil. The new additives perform well in these base fluids and are designed to be stable to temperatures in excess of 550°F.The invert emulsion system can be weighed to densities above 19.5ppg using barite or alternative weight materials.

GENERIC PRODUCT	PRIMARY FUNCTION	SECONDARY FUNCTION
Polyamides	Emulsifiers	
Fatty acid amidoamide	Emulsion stability	Solids tolerance
Organoclay 1	Primary viscosifier	HPHT fluid loss
Organoclay 2	Sag preventer	Rheology modifier
Treated inorganic materials	HPHT fluid loss	Rheology modifier

As we get deeper, temperatures increase beyond the temperature limits of down-hole tool components rendering the tools unusable. Yet adequate knowledge of down-hole pressure is essential to adequately manage kicks, stuck pipe and to reach deep reservoir targets safely. Accurate hydraulics software can provide the operator with some of these pressure related parameters like Equivalent Circulating Density (ECD) and overall system pressure losses for stand pipe pressure.

Drilling efficiency

HPHT drilling requires higher density drilling fluid which is achieved by adding dispersed weight material such as barite. The addition of the dispersed weight material increases the dispersed solids concentration, increases drilling fluid viscosity, limits available hydraulic horsepower at the bit and reduces cutting efficiency. The reduced hydraulic & cutting efficiency combined with higher competency formations at depth, high compressive strengths of these formations due to the higher confining stresses at the high bottom hole pressures and the use of heavy set bits typically required for the higher competency formations result in very low drilling efficiency, low penetration rates, low depths of cut and fine drill solids. These fine drill solids are difficult to remove with surface solids control equipment and tend to build up in the drilling fluid adding to the drilling fluid viscosity further reducing drilling efficiency, adding to time on location and increased drilling costs.

HPHT Applications require special drilling fluids with low ECD and reduced sag tendencies to avoid downtime due to mud conditioning and to prevent rigs from having to operate at or near hydraulic limits .Such fluids would also be less likely to result in down hole losses and the often considerable cost of lost circulation.

Higher specific gravity weight materials (relative to barite) provide lower solids content at equivalent mud densities. In the past, the use of these materials was limited by the availability and higher abrasion as a result of greater hardness. During the last five years three products (ilmenite, manganese tetroxide and finely ground hematite) have been used successfully in different parts of the world. Some the special HS & E considerations like dusting and skin stain have been adequately addressed with the use of proper PPE and barrier creams applied before coming into contact with treated fluids.

HPHT Applications include: low abrasion of tubular goods, higher rates of penetration due to lower solids loading and low pressure loss for increased hydraulic horsepower. In addition these alternate materials resist attrition and build up of fines during shearing, relative to barite and they are considered more environmentally acceptable due to generally lower concentration of trace heavy metals.

Other considerations

Trip time increases with depth and consequently exposure of the drilling fluid to temperature and pressure under static conditions. Running into the bottom and circulating cooler, denser fluid around can significantly increase the chances of fracturing the formation. The swabbing effect when tripping out also generally increases with depth, but has also been shown to occur when tripping in to the hole, due to drill string elasticity and oscillation. Hydraulic modeling can help optimize trip speed to prevent formation fracture or influx.

High flow line temperatures are also a concern with regard to rig crew safety and well control equipment elastomers. Mud coolers or chillers have made significant contributions to reducing mud temperatures while circulating. Some mud coolers have been shown to reduce mud circulating temperature by approx. 15°F per cooling unit. This temperature reduction also benefits down-hole tools and temperature-sensitive mud products while reducing the possibility of the drilling fluid reaching its flash point at the surface.

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DRILLING FLUIDS FOR HPHT WELLS

Oil Based Mud

- An oil based mud system is one in which the continuous phase of a drilling fluid is oil. When water is added as the discontinuous phase then it is called an invert emulsion. These fluids are particularly useful in drilling production zones, shales and other water sensitive formations, as clays do not hydrate or swell in oil.

- They are also useful in drilling high angle/horizontal wells because of their superior lubricating properties and low friction values between the steel and formation which result in reduced torque and drag.

Invert emulsion fluids (IEFs) are more cost-effective than water muds in the following Situations:

1. Shale stability
2. Temperature stability
3. Lubricity
4. Corrosion resistance
5. Stuck pipe prevention
6. Contamination
7. Production protection

Oil Based Mud (Basic Chemistry)

Invert emulsion (most common OBMs) are formulated to contain moderate to high water concentrations. Special emulsifiers are added to emulsify water as the internal phase and prevent the water from breaking out and coalescing into large droplets. These water droplet if not tightly emulsified, can water wet the already oil-wet solids and effect the emulsion stability.

Chemical composition of OBM's

1. **Base oils:**
    - Only low toxic base oil should be used as approved by the authorities. This is the external emulsion phase. In many areas, though quite detrimental to environment, diesels were used to formulate and maintain OBM'S.

- Crude oils had sometimes been used too, instead of diesel oil but posed tougher safety problems. Thus today, low toxic mineral oils & new synthetic fluids replace diesel and crude due to their low toxicity.

2. **Water:**
   - Internal emulsion phase. This gives the Oil/Water Ratio (OWR), the% of each part as a total of the liquid phase. Generally, a higher OWR is used for drilling troublesome formations. The salinity of the water phase can be controlled by the use of dissolved salts, usually calcium chloride. Control of salinity in invert oil muds is necessary to "tie-up" freewater molecules and prevent any water migration between the mud and the open formation such as shales.

   - Water is an integral part of the invert emulsion and can contain salts such as calcium or sodium chloride .Sea water is often used in offshore.

3. **Primary Emulsifiers:**
   - Calcium soaps are the primary emulsifiers in oil muds. These are made in muds by reaction of lime and long chain fatty acids. Soap emulsions are strong emulsifying agents but may take reaction time before emulsion is actually formed.
   - Emulsifiers are basically surfactants that reduce the surface tension between water droplets and oil. They stabilize the mixture by being partially soluble in water and partially soluble in oil. They may be anionic, cationic or non ionic.

4. **Secondary emulsifiers:**
   - They are powerful oil wetting chemicals which generally do not form emulsions but wet solids before the emulsion is formed. Also used to prevent from water intrusion, these wetting agents are surface active agents that reduce interfacial tension and contact angle between a liquid and solid. Wetting agents have one end that is soluble in the continuous phase liquid and the other end which has strong affinity for solid surfaces.
   - In invert OBM, wetting agents causes solids to be wet with oil. These solids (barite, clay and drilled solids) must be wetted with the continuous liquid phase of the drilling fluid or they will aggregate and settle. Most solids naturally have a preferential water wetting tendency and require oil wetting agents to wet them with oil.

5. **Lime:**

- Lime is essential in OBM'S. It neutralizes fatty acids in the fluid, stabilizes the emulsion when present in excess and controls alkalinity. In the field it neutralizes acid gases (H2S AND CO2).

Drilling Fluid Additives

There are many drilling fluid additives which are used to develop the key properties of the mud. The variety of fluid additives reflect the complexity of mud systems currently in use. The complexity is also increasing daily as more difficult and challenging drilling conditions are encountered.

The common drilling fluid additives used are:

1. **Weighting materials:**

- Weighting materials or densifiers are solids material which when suspended or dissolved in water will increase the mud weight. Most weighting materials are insoluble and require viscosifiers to enable them to be suspended in a fluid.
- Mud weights higher than water (8.3 ppg) are required to control formation pressures and to help combat the effects of sloughing or heaving shales that may be encountered in stressed areas.

Material	Specific Gravity
Galena	7.4-7.7
Haematite	4.9-5.3
Magnetite	5.0-5.2
Illmenite	4.5-5.1
Barite	4.2-4.6
Siderite	3.7-3.9

Commonly used Weighting Materials

- Barite (or barytes) is barium sulphate, $BaSO4$ and it is the most commonly used weighting material in the drilling industry. Barium sulphate has a specific gravity in the range of 4.20 - 4.60. Most commercial barite contain impurities including quartz, chert, calcite, anhydrite, and various silicates which slower its specific gravity. It is normally supplied to a specification where the specific gravity is about 4.2. Barite is preferred to other weighting materials because of its low cost and high purity. Barite is normally used when mud weights in excess of 10 ppg are required. Barite can be used to achieve densities up to 22.0 ppg in both water-based and oil -based muds. However, at very high muds weights (22.0 ppg), the rheological properties of the fluid become extremely difficult to control due to the increased solids content.

2. **Viscosifiers:**

- The ability of drilling mud to suspend drill cuttings and weighting materials depends entirely on its viscosity. Without viscosity, all the weighting material and drill cuttings would settle to the bottom of the hole as soon as circulation is stopped. One can think of viscosity as a structure built within the water or oil phase which suspends solid material. In practice, there are many solids which can be used to increase the viscosity of water or oil. The effects of increased viscosity can be felt by the increased resistance to fluid flow.
- Bentonite Clay- This is the most widely used additive in the oil industry. Bentonite is classified as sodium bentonite or calcium bentonite. In fresh water, sodium bentonite is more reactive than calcium bentonite and hence, in terms of performance, bentonite is classed as "high yield" (Sodium Bentonite) or "low yield" (Calcium Bentonite).
- Bentonite is used to build viscosity in water which is required to suspend weighting materials and drill cuttings. When clay is dispersed in water, viscosity is developed when the clay plates adsorb water layers on to their structure. Each or several stacked water layers are shared by two clay plates; these repeating structures of clay plates and their attached water layers result in a viscous structure. The dispersion process will only take place in fresh water. If the clay is used in salt muds, it has to be prehydrated in fresh water.

3. **Filtration Control Material:**

- Filtration control materials are compounds which reduce the amount of fluid that will be lost from the drilling fluid into a subsurface formation caused by the differential pressure between the hydrostatic pressure of the fluid and the formation pressure.
- Bentonite, polymers, starches and thinners or deflocculants all function as filtration control agents. Bentonite imparts viscosity and suspension as well as filtration control. The flat, "plate like" structure of bentonite packs tightly together under pressure and forms a firm compressible filter cake, preventing fluid from entering the formation.
- Polymers such as Polyanionic cellulose (PAC) and SodiumCarboxymethylcellulose (CMC) reduce filtrate mainly when the hydrated polymer chains absorb onto the clay solids and plug the pore spaces of the filter cake preventing fluid seeping through the filter cake and formation. Filtration is also reduced as the polymer viscosifies the mud thereby creating a viscosified structure to the filtrate making it difficult for the filtrate to seep through.

4. **Rheology Control Materials:**

- When efficient control of viscosity and gel development cannot be achieved by control of viscosifier concentration, materials called "thinners", "dispersants", and/or "deflocculants" are added. These materials cause a change in the physical and chemical interactions between solids and/or dissolved salts such that the viscous and structure forming properties of the drilling fluid are reduced.
- Thinners are also used to reduce filtration and cake thickness, to counteract the effects of salts, to minimize the effect of water on the formations drilled, to emulsify oil in water, and to stabilize mud properties at elevated temperatures. Materials commonly used as thinners in clay- based drilling fluids are plant tannins, lignitic materials, lignosulfonates, and low molecular weight, synthetic, water soluble polymers.

5. **Alkalinity and pH control Materials:**

- pH affects several mud properties by detection and treatment of contaminants such as cement and soluble carbonates and solubility of many thinners and divalent metal ions such as calcium and Magnesium. Alkalinity and pH control additives include: NaOH, KOH, Ca(OH)2, NaHCO3 and Mg(OH)2. These are compounds used to attain a specific pH and to maintain optimum pH and alkalinity in water base fluids.

6. **Lubricating Materials:**

- Lubricating materials are used mainly to reduce friction between the wellbore and the drillstring. This will in turn reduce torque and drag which is essential in highly deviated and horizontal wells. Lubricating materials include: oil (diesel, mineral, animal, or vegetable oils), surfactants, graphite, asphalt, gilsonite, polymer and glass beads.

7. **Shale Stabilizing Materials:**

- There are many shale problems which may be encountered while drilling sensitive highly hydratable shale sections. Essentially, shale stabilization is achieved by the prevention of water contacting the open shale section. This can occur when the additive encapsulates the shale or when a specific ion such as potassium actually enters the exposed shale section and neutralises the charge on it. Shale stablisers include: high molecular weight polymers, hydrocarbons, potassium and calcium salts (e.g. KCl) and glycols.

CHAPTER-5

PREPARATION OF OIL BASE MUD

Aim: To design an oil base mud

Procedure:

1. The contents of the formulation were mixed at 6000 RPM in the Silverson's mixer in the following sequence :
   Base oil + Primary emulsifier + Secondary emulsifier + Oil wetting agent + Organophillic Clay + Lime + Fluid loss additive + Brine at a duration of 5 minutes each.

2. After addition of all additives, the contents were allowed to mix in Silverson mixer for next 30 minutes at 6000 RPM.

3. Barytes if needed is added after this initial formulation in Hamilton Beach Mixer.

4. Samples of the invert emulsions so prepared was hot rolled for 16 hrs at 120°C in a pre-heated roller oven.

5. After 16 hrs of hot rolling, open the door of roller oven and the samples are cooled for 30 minutes.

6. The invert emulsion so formulated was allowed to retain the ambient temperature before analyzing it for:

   - Specific Gravity: The specific gravity/ density of the formulation was measured by Baroid mud balance at ambient temperature 24 ± 2°C.

   - Rheological properties: The general practice as recommended by API is to measure rheological properties of Oil based mud at 49°C(120°F) or at 65°C(150°F) using high temperature cup supplied by Fann instruments. The rheology throughout the experiments was determined at 49°C and for the recommended formulation, rheology was determined at 600,300, along with Gel_0 and Gel_{10}.

- HTHP Fluid Loss: The HTHP Fluid loss was determined at 120°C and 500 psi differential pressure as per API standard practices measured using HTHP Fluid loss Apparatus.

- Emulsion Stability (ES): The emulsion stability was measured as the voltage required to initiate the flow of electric current .It was measured with the help of portable digital Fann Emulsion Tester 23 D available at IDT at 120°F.

Result: The oil base mud for HPHT well was designed and the necessary properties (Specific gravity, viscosity , HTHP fluid loss and Emulsion Stability) were measured and calculated.

Experiment 1

Aim: To prepare an invert emulsion mud with Pandrill 10(Base oil) with the Base oil: Aqueous media in the ratio of 70:30

Procedure:

- Initially the base oil (Pandrill 10) is taken in a container in the desired quantity and mixed using the Silverson's Mixer at a speed of 6000 RPM.

- Each of the additives is added to the base oil in the following sequence with 05 minutes stirring in Silverson's Mixture.
  I. Pandrill 10 - Base oil
  II. Cristol 2909 – Primary Emulsifier
  III. Cristol 3009 – Secondary Emulsifier
  IV. Ashaorg D9 – Organophillic Clay
  V. Lime
  VI. Brine 35% $CaCl_2$

- This is followed by 30 minutes stirring after addition of all the additives.

- The following mud rheology is then measured with the Fann V-G Viscometer by placing the mud in the cup and starting the motor, the sleeve rotates in the mud. The readings are observed on the dial of the Viscometer
  I. $\Phi600$
  II. $\Phi300$
  III. Apparent Viscosity(AV) in cp = $\Phi600/2$

IV. Plastic Viscosity (PV) in cp = Φ600- Φ300

V. Yield Point (YP) in lbs/100ft^2 = Φ300- PV

VI. Gel_0- Reading on Viscometer dial when sleeve is running at 3 RPM

Gel_{10}- Reading on viscometer dial after the mud is kept at stand still for 10 minutes and then started at 3 RPM, the highest reading is noted All these readings are taken maintaining the temperature of mud sample in the cup at 120°F

- The mud Balance is then filled with the mud and weighed on the balance to determine the mud weight in Specific Gravity.

- Electrical Stability of the emulsion is determined using Electrical Stability Tester Apparatus, whose electrode when dipped in the mud will give the electrical stability in Volts .The Electrical stability measured at 120°F. Average of 3 readings is taken.

- After that the HPHT cell is filled with mud, the lid is closed and the apparatus is pressurized to 500 psi and temperature of 120°C is obtained for 30 minutes. The filtrate is obtained from the cylinder through a tube, which is collected and measured in a graduated cylinder in ml.

- The mud is then loaded with barites to obtain a specific gravity of 1.50 and then mixed in the Hamilton Beach Mixer.

- After obtaining the desired specific gravity and proper mixing, the mud is poured into cells and then put into the oven for hot rolling at 120°C for period of 16 hours.

- After hot rolling for 16 hours, the cells are removed from oven and cooled to room temperature and all the above readings are noted once again.

Tabulation

S.No.	Ratio of Base oil: Aqueous Media	Mud Formulation	Percentage of the additive (w/v)	Φ600/Φ300	Apparent Viscosity in cp	Plastic Viscosity in cp	Yield Point in lb/100 ft^2	Gel0/Gel10	Sp. Gr.	ES in Volts (at 49°C)	HTHP in ml (at 120°C/500 psi)
1	70:30	Pandrill 10	70								
		PE-Cristol 2909	2.0	54/35	27	19	16	04/08	0.92	768	6.0
		SE-Cristol 3009	0.5	Loaded with barites up to Sp.Gr of 1.50	and After Hot Rolling at 120°C for 16 hrs and cooling to Room Temp.						
		OC-Ashaorg D9	3.0	118/78	59	40	38	13/22	1.52	1384	4.8
		Lime	2.5								
		Brine 35% $CaCl_2$	30								

Result: The invert emulsion mud was prepared with Pandrill 10 and all the desired properties were calculated as shown in the above table

Experiment 2

Aim: To prepare an invert emulsion mud with Pandrill 10(Base oil) with the base oil: Aqueous media in the ratio of 80: 20

Tabulation

S.No.	Ratio of Base oil: Aqueous Media	Mud Formulation	Percentage of the additive (w/v)	Φ600/φ300	Apparent Viscosity in cp	Plastic Viscosity in cp	Yield Point in lb/100 ft²	Gel0/Gel10	Sp. Gr.	ES in Volts (at 49°C)	HTHP in ml (at 120° C/500 psi)
2	80:20	Pandrill 10	80								
		PE-Cristol 2909	2.0	39/26	19.5	13	13	03/05	0.92	1020	5.6
		SE-Cristol 3009	0.5	Loaded with barites up to Sp.Gr of 1.50 and After Hot Rolling at 120°C for 16 hrs and cooling to Room Temp.							
		OC-Ashaorg D9	3.0	102/69	51	33	36	10/18	1.52	1394	4.0
		Lime	2.5								
		Brine 35% $CaCl_2$	20								

Result: The invert emulsion was prepared with Pandrill 10 in the ration 80:20 and the required properties were obtained and calculated.

Inference:

- From experiment 1 & 2, it is observed that when the invert emulsion mud is loaded with barites , the Rheology of mud(Plastic viscosity(PV), Apparent viscosity (AV), Yield point(YP) , Gelation and Specific Gravity increases and the HPHT Fluid loss decreases. This is because as barites are added, the density and viscosity of mud increases but thin filter cake will be formed and hence fluid loss obtained is minimum.

- The ratio of base oil: aqueous media can be taken as 70: 30 or 60: 40, thereby decreasing the concentration of base oil and increasing water, since water increases density and viscosity and this helps in easier lifting of cuttings and the emulsion can be used for normal pressured formations.

- The ratio of base oil: aqueous media can be taken as 90: 10, thereby increasing base oil concentration and decreasing water, if the formation is sub- hydrostatic (pressure below hydrostatic pressure) and no problem is observed in lifting cuttings.

Oil Mud Formulating Problems

The difficulties encountered when formulating OBM's are essentially linked to the presence of a dispersed phase (brine) in the oily continuous phase. Moreover every single OBM is different from the other and require a dedicated mixing procedure.

I. **Mixing Procedure:**
The addition of components in their proper sequence when initial mixing an oil mud, will optimize the performance of each product. The order of addition listed is the most common procedure for preparation of oil based mud, though each mud system may require some modifications of the procedure.
    - The mixing time may vary depending upon the amount of shear either at rig or at the mud plant.
    - Organophillic viscosifiers require considerable quantity of shear to fully develop their viscosity. Therefore, more of the additive may be required on initial mixing.
    - As the oil mud is used over a couple of days, the emulsion stability and fluid loss control will improve compared to what mud was when initially mixed.

II. **Rheology Optimization**
The first parameter to control is rheology. This presence of an organophillic clay is essential in developing viscosity. However organophillic clay does not develop viscosity when dispersed in the oil phase. Viscosity actually increases when invert emulsion is formed, the organophillic clay being dispersed at the interface between oil and water droplets.

Four components are then essential to develop viscosity
- The oil phase
- The water phase

- The emulsifying package
- The organophillic clay

Usual concentrations for the organophillic clay is 3-4%. Once brine is added the viscosity increases.

Sometimes a very stong gel develops depending upon the chemistry of surfactants and/ or the nature of the oil, the alternatives are:

If the mud has already been prepared and if it is not possible due to costs, volumes and environmental considerations to prepare the whole mud again then alternatives available are:

- To add some thinners, these additives reduce interactions at the interface
- To add some emulsifying surfactants to thin the emulsion
- To remove low gravity solids with solid control equipment and/or to dilute the mud.
- To increase oil water ratio, if water content is too high.

If the mud has not yet been prepared yet and if gelation is expected , the solution is to add organophillic clay once the emulsion is formed. This helps in reducing the strength of the gel developed.

If viscosity is too low, alternatives are:

- Add water, emulsifier and gellant.
- If the temperature is very high, add polymeric viscosifier.

III. Stability of the emulsion

The stability of the formulation is very critical for the mud Engineer.

- Rheology: There are different ways to check stability, but first is to stable rheology
- Settling: We consider that if no sag appears when the mud is heated to 120°F in the cup before measuring rheology, the mud is considered to be stable.
- Electrical Stability (ES): It is the standard procedure to decide whether the emulsion is stable or not. We can consider a mud is stable when its ES is above 400 volts, but this is only relative indication.

IV. How to control Stability:

- Check the amount of surfactants.
- Check the lime content: Lime is essential for mud stability. Excess of lime benefits the mud whereas lack of lime is detrimental to the stability.

- Settling: If sag is observed while viscosity is sufficient, the solution is to add some oil wetting chemicals. Now a days contractors use tri-ethanol amine (TEA) to assist or even replace lime.
- Low electrical stability: Water wet solids, un-dissolved solids, inadequate concentration of emulsifiers, inadequate concentration of lime for emulsifiers generate low ES readings.
- Presence of gas: Another problem linked to the stability of the mud is the presence of bubbles (air or acid gas). To solve this problem, we use scavengers (zinc oxide) to degas the mud.

V. Alkalinity Control

Every fluid in the well must be alkaline. The additives used to control alkalinity are lime, tri-ethanol amine, soda ash or potash.

VI. Fluid loss control:

A low filtration rate and water free filtrate is critical properties of oil muds to ensure the well is stable. (No fluid invasion through the formation, no shale swelling).

Fluid loss control agents are used in muds to get good filtration properties and these chemicals are very effective.

The problem arises:

- If the emulsion is too weak, the filtration rate increases dramatically and moreover some water can be found in the filtrate. The solution is to add primary emulsifier and lime systematically.
- If the filtration properties were good and that due to high temperature down hole ,the rate increases, then the mud needs to be stabilized. Usual treatment is to add some emulsifier ,eventually combined with wetting agent, lime and an organophillic fluid loss control additive.

VII. Free top oil

After periods of inactivity, free oil may cover the surface of pits. Agitate the mud in the pits or add organophillic clay to increase the viscosity if required.

CHAPTER-6

APPARATUS DESCRIPTION

Hamilton Beach Mixer

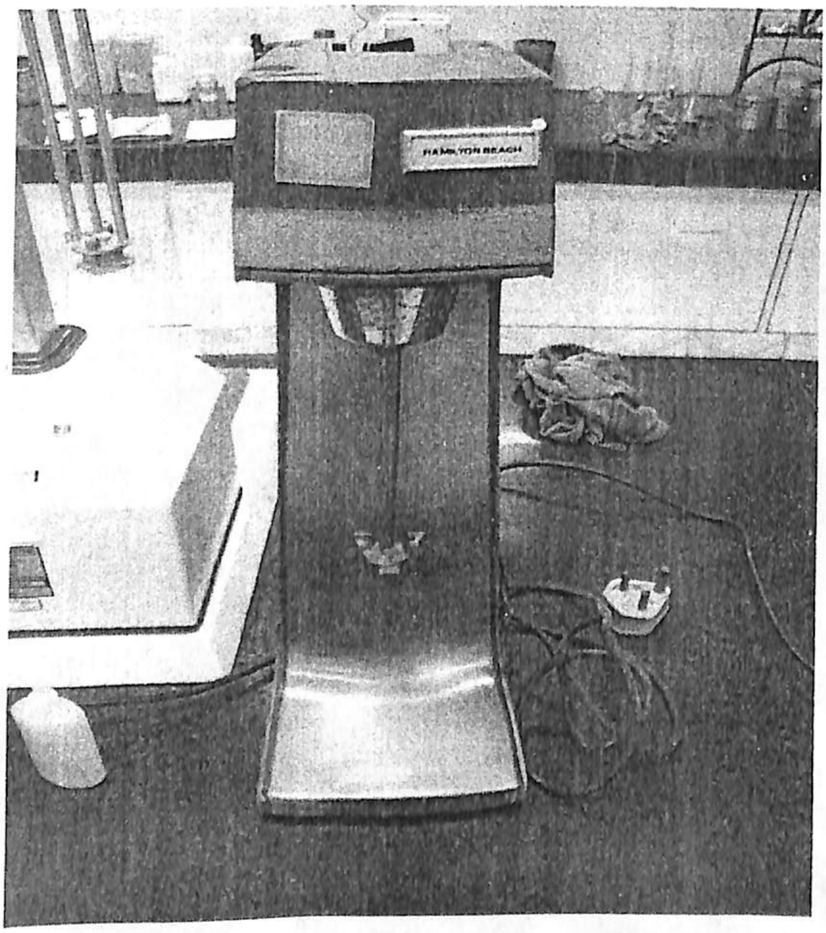

Figure 1. Hamilton Beach Mixer

- Hamilton Beach mixer and Silverson's mixer are used in the laboratory tests of mud materials. They do not however produce the high shear rates that exist in the circulation of the drilling fluid in the well. High shear rates are only obtained when there is little clearance between the stator and the rotor or when mud is pumped through a small orifice or opening.

- They can be used for short periods of time because the temperature rises rapidly, and consequent loss of water by evaporation. Silverson's mixer can attain a maximum speed of 6000RPM and Hamilton of 18,000 RPM. If mud is loaded with Barites, Hamilton mixer is used to mix due to the high mud density, which can damage blades of Silverson's mixer. For large amounts of mud, it is best to use high shear rate mixer such as the Eppenbach.

Silverson Mixer

Figure 2. Silverson Mixer

Mud Balance

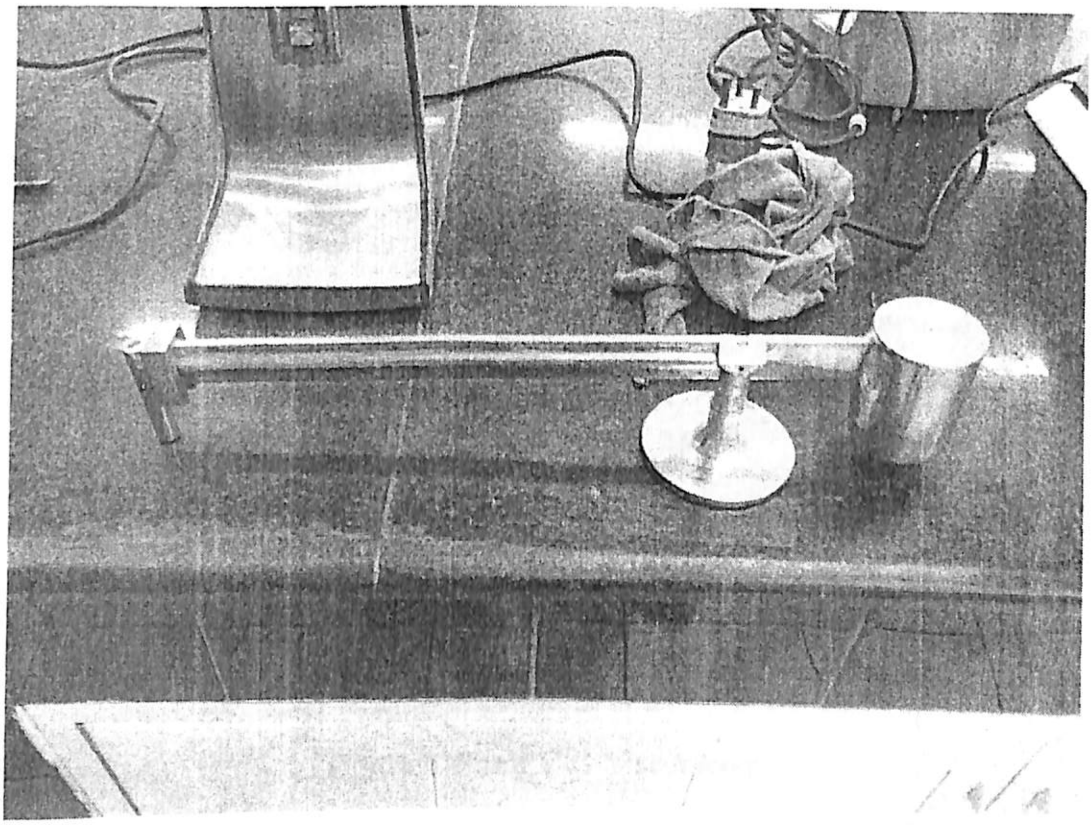

Figure 3. Mud Balance

- Density or Mud Weight is determined by weighing a precise volume of mud in the Mud balance. The mud balance provides the most convenient way of obtaining a precise volume.

- The procedure is to fill the cup with mud, put on the lid, wipe off excess of mud from the lid, move the rider along the arm till a balance is obtained and read the density at the side of the rider towards the knife edge.
- Density is expressed in pounds per gallon (lb/gal), pounds per cubic feet (lb/ft^3), grams per cubic centimeter (gm/cm^3).

Conversion factors are:
Specific Gravity (SG) = g/cm^3 = (lb/gal)/ 8.33 = (lb/ft^3) / 62.3

Fann V-G Viscometer

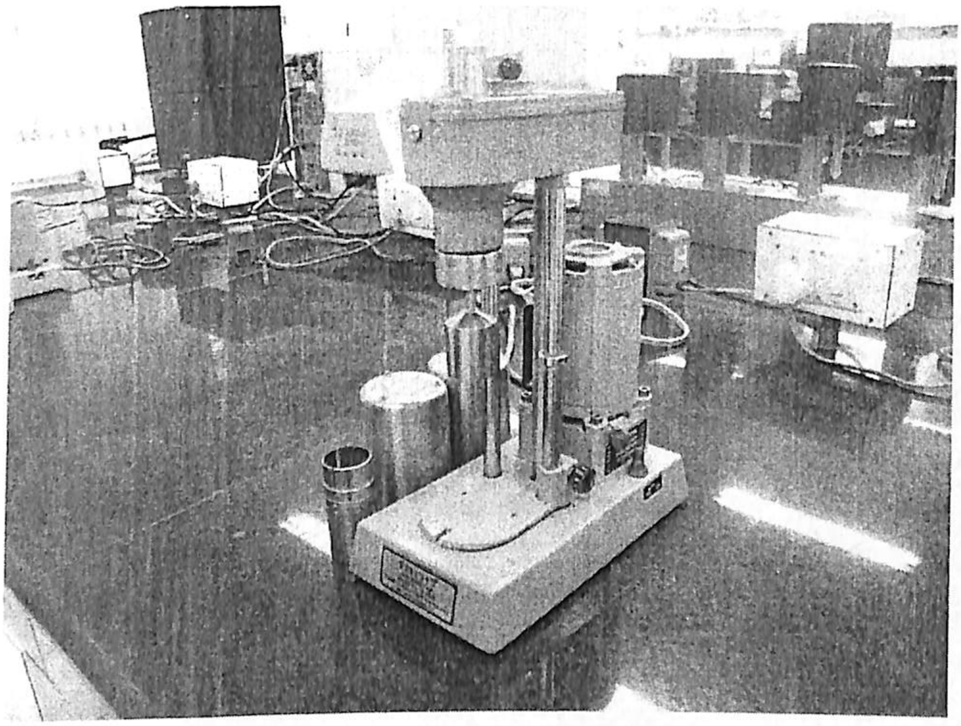

Figure 4. Fann V-G Viscometer

- Viscometer is a device used to measure the viscosity and yield point of mud. A sample of mud is placed in a slurry cup and rotation of a sleeve in the mud gives readings which can be mathematically converted into apparent viscosity (AV), plastic viscosity (PV) and yield point (YP). Multi-speed viscometers are recommended whenever possible since readings can be obtained at 600, 300, 200, 100, 6 and 3 rpm.

- Apparent Viscosity: The apparent viscosity in centipoise equals the 600 rpm reading divided by 2.
  [AV. = $\Phi 600/2$ in centipoise]

- Plastic Viscosity: Reading at 600 rpm - reading at 300 rpm.
  [PV = $\Phi 600 - \Phi 300$ in centipoise]

- Yield Point :300 rpm reading - plastic viscosity
  [YP = $\Phi 300 - PV$ in lb/100 sq. ft.]

API and HPHT Fluid loss Apparatus

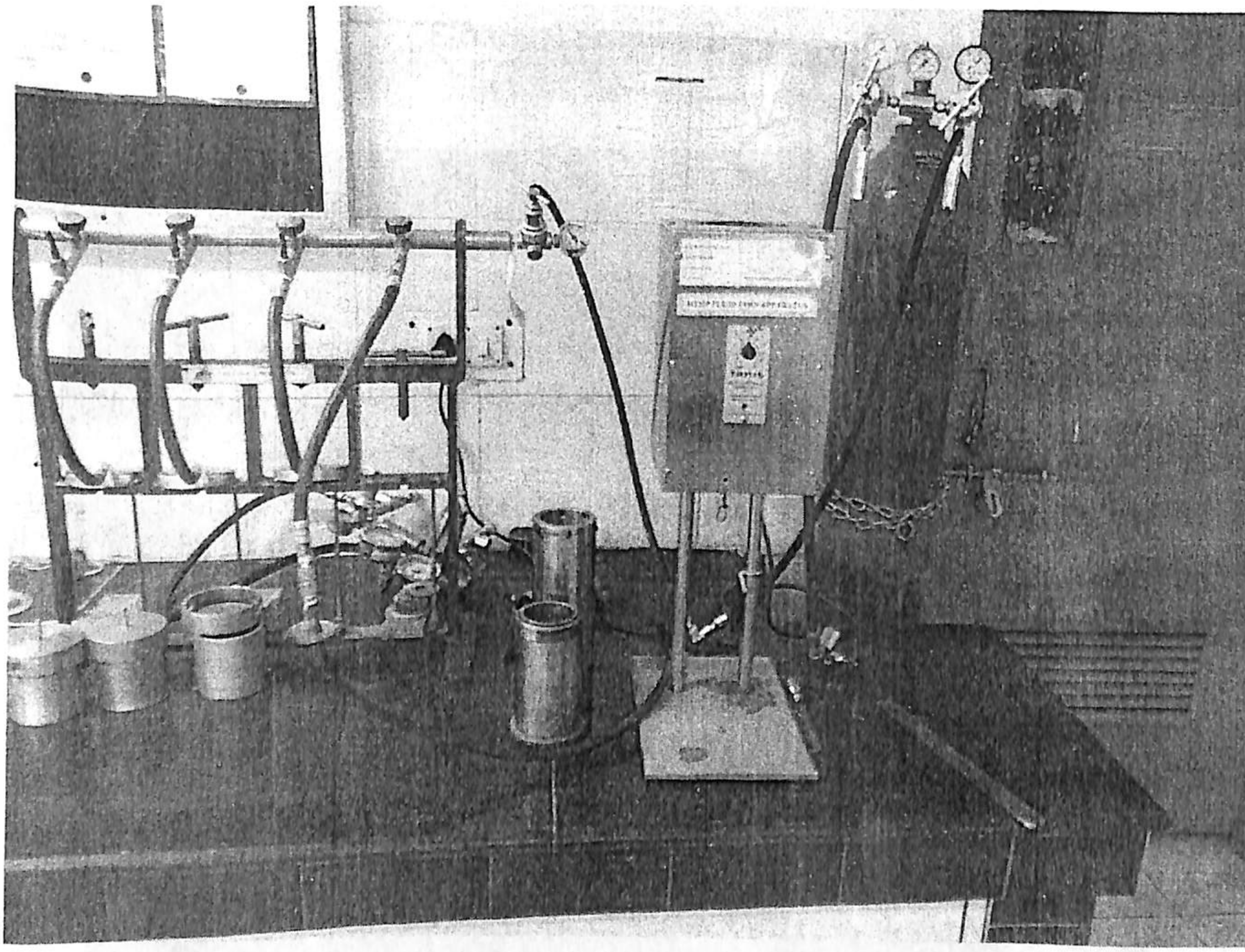

Figure 5. API and HPHT Fluid loss Apparatus

- Both tests work on filling a cell with drilling fluid, and sealing it shut. Inside the cell is a filter paper that has been placed between the mud and the aperture in the cell. Pressure is applied to the cell which forces the mud and solids through the filter paper.

- The solids accumulating on the filter paper form a filter cake and then the filtrate passing through the paper is collected in a graduated cylinder. The mud in the cell is pressurised for 30 min and the fluid or filtrate is collected and measured. The filter paper is also collected, washed, then examined and the deposited filter cake is measured.

- HPHT tests with the cell are usually carried out at a temperature of 120°C and pressure of 500 psi to determine the fluid loss.

Electrical Stability Tester

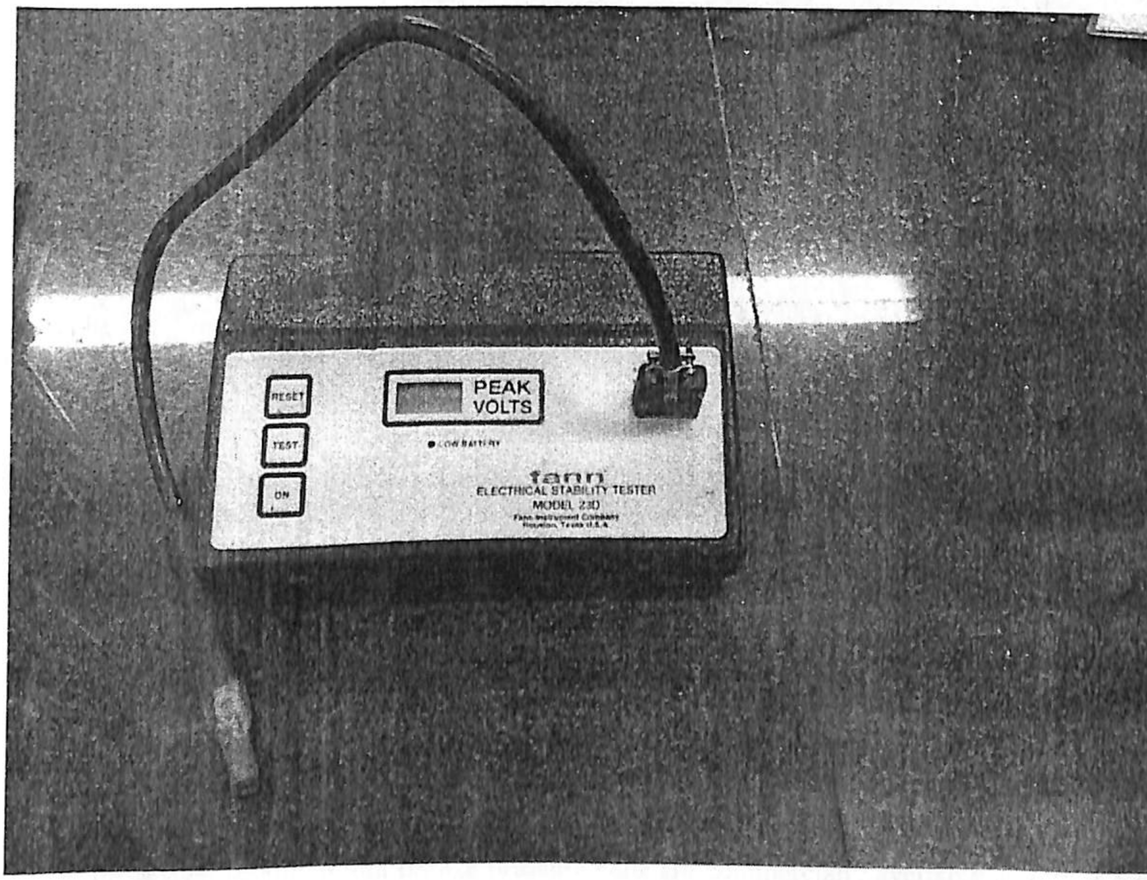

Figure 6. Electrical Stability Tester

- Apparatus used to determine the Electrical Stability (ES) in Volts of the Emulsion. We can consider a mud to be stable when its ES is above 400 volts.

- Electrical Stability is measured by dipping the electrode of the tester in the cup filled with mud and maintained at 120°F indicated by the thermometer. On pressing the test button, the voltage appears on the screen. Three such readings are noted and the average is taken.

Pressure Cells

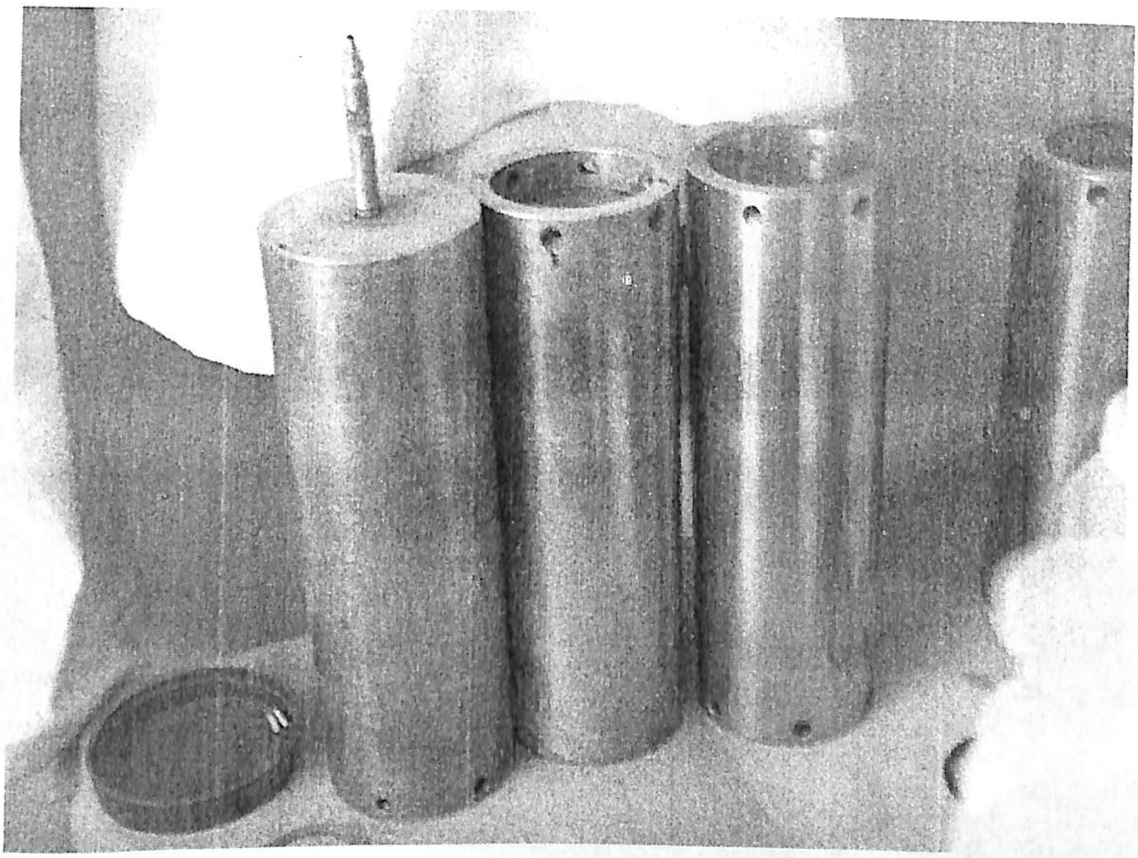

Figure 7. Pressure Cells

- Stainless steel or aluminium bronze pressure cells are commercially available in 260 or 500 cm^3 sizes. To prevent boiling of the liquid phase, the cells are pressurized with nitrogen or carbon dioxide through connections provided. The applied pressure must be equal to the vapour pressure of the liquid at the test temperature

- To simulate aging of the mud while it is circulating in the well, the cells are rolled in an oven for at least 16 hours at the average well circulating temperature. The cells are then cooled to room temperature; the rheological and filtration properties are measured and compared to the same properties before aging.

Roller Oven

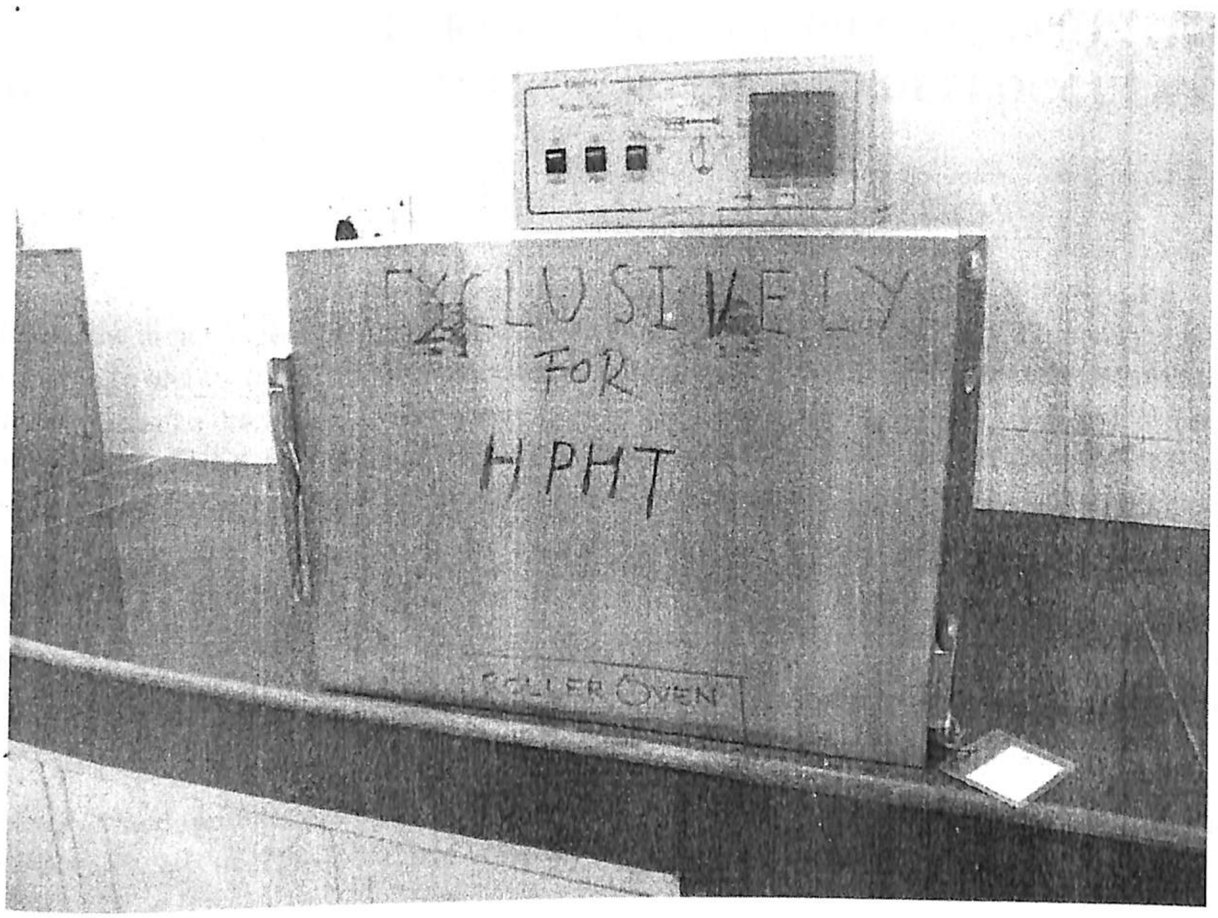

Figure 8. Roller Oven

CHAPTER-7

CASE STUDY ON FORMULATION OF SPECIFICATION OF HPHT FLUID LOSS CONTROL AGENT AND DEFLOCCULANT

Introduction

Most of the high temperature wells taken for drilling by ONGC, exhibited maximum temperature in the range of 150-170°C. First time in Rajahmundry Asset, well PGAB was taken for drilling, where maximum bottom hole temperature expected was more than 220°C. At this extreme temperature, all the conventional mud chemicals loose their properties and degrade. Drilling fluid experiences high gel and HPHT fluid loss. So to control rheology, gel and HPHT fluid loss at this elevated temperature special chemical additives were screened and extensive experiments carried out to ascertain these properties.

The HPHT well PGAB has been drilled successfully by these chemicals and drilling in second HPHT well SMA_AA is in progress. In both the wells bottom hole temperature is more than 200°C (confirmed by log data) and pressure about 10,000 psi.

Testing of mud formulations have been done at 225°C because it covers the range of normal high temperature wells i.e. 150-175°C and also very high temperature wells i.e. beyond 200°C.

Critical Problems in HPHT Drilling Fluid Design

- High temperature gelation: Due to flocculation of clays and by thermal degradation of normal chemicals being used for oil well drilling.
- High temperature fluid loss: Generally increases with increase in temperature due to gelation and thermal degradation of polymers or other chemicals used for control of filteration loss.
- Rheological properties: For drilling HPHT wells, high density drilling fluids are used which have high volume fraction of solids as weighing material. Therefore proper control of rheology is very essential because small increase in colloidal size drilled solids can increase unacceptable viscosity and there by excessive pressure losses, surge and swab pressure and gelation. On the other hand low rheology can promote poor hole cleaning and sag of weighing material.

- Chemical degradation: Except weighing material chemical products degrade thermally at elevated temperature. So proper screening of chemicals to be used is necessary.

HPHT Wells drilled in Rajahmundry

SL No	Name of the Well	Maximum Temperature (°C)
1.	PGAB	220
2.	NPG-AA	199
3.	SMA_AA	203
4.	SUAC	165
5.	NGAC_RJY	160
6.	VGSW-AA	190
7.	MSAB_RJY	158
8.	NGAD_RJY	190
9.	KLAA_RJY	232
10.	MSAA_RJY	168

Scope

- Arrangement of HPHT chemicals from Rajahmundry asset.
- Conducting large scale testing at high temperature (220°C/225°C) on the drilling fluid formulations
- Framing of specifications

Experimentation

- 4 cp Bentonite suspension was used to prepare drilling fluid formulation as high concentration of clay can cause excessive gel at high temperature
- A variety of mud formulations were prepared using different chemicals , kept in an aging cell and hot rolled at 220/ 225°C in roller oven for 16 hours. After hot rolling ,samples were cooled at room temperature. Rheology and API fluid loss were measured at 160±2°C and 500 psi pressure difference.

Discussion and Evaluation of the data (Results)

- Table 1 incorporates the data on rheology and HPHT fluid loss of the blank formulation where 4 cp Bentonite suspension was loaded with barite up to 2.03 Sp. Gr. and treated with caustic soda, lignite and Sulfonated asphalt. After hot rolling at 225°C, rheology of the formulation could not be measured and HPHT fluid loss is very high close to 105 ml.
- Table 2 incorporates data on rheology and HPHT fluid loss of the formulation having 4 cp pre hydrated bentonite loaded with barite and HPHT fluid loss polymer and deflocculant mixed in it. HPHT fluid loss is 58 ml which is quite high.
- Table 3 incorporates data on rheology and fluid loss of the mud prepared by mixing HPHT fluid loss polymer in 20 cp Bentonite suspension loaded with 1.2 Sp. Gr . Initial rheology is very high but after hot rolling PV and YP readings are within limits but HPHT fluid loss is high.
- Table 4 incorporates data on rheology and fluid loss of the mud prepared by mixing lignite, suphonate asphalt, HPHT fluid loss polymer and deflocuulant in the 4 cp Bentonite suspension and loaded with barite. The formulation properties are satisfactory.
- In table 5, same mud formulation as in Table 4 was repeatedly to verify the results and it gave parameters of rheology and fluid loss in desired range. So this formulation was chosen for framing the specification.
- In table 6, same formulation as given in table 4 and 5 was used except HPHT deflocculant, which was not mixed to see the effect of deflocculant on mud properties. It is evident from the data the HPHT fluid loss increased from 18 ml to 30 ml.
- In table no 7 and 8, curing temperature was reduced to 175°C to see the effect of lower temperature on the formulation. It is evident from the data that at lower curing temperature HPHT fluid loss is in the desired range of 20 ml.

- In table no 9, same formulations was used as in table no. 8.Only curing temperature was increased to 225°C and increase in HPHT fluid loss was noticed from 0 ml to 32 ml.
- In table no 10, same formulation as used in table 4 and 5 was prepared for repeatability test and gave satisfactory result as earlier.

Conclusion

- It is clear that the data presented above that the following formulation is the best suited to drill up to high temperature.
  4 cp pre hydrated Bentonite suspension + Barite up to desired sp. gr + pH with Caustic soda + Lignite 1.5% + Suphonated Asphalt 2% + HPHT fluid loss reducing polymer 1.5% + HPHT Deflocculant 0.5%.

- When curing temperature is lowered from 225 to 175°C for same formulation, improvement in HPHT fluid loss is observed.

Recommendations

- As concluded above following formulation is best suited for drilling wells having high formation temperature.
  4 cp pre hydrated Bentonite suspension + Barite up to desired sp. Gr. + pH with caustic soda + Lignite 1.5% + Sulphonated asphalt 2% + HPHT fluid loss reducing polymer 1.5% + HPHT Deflocculant 0.5%.
- Use of micronized barite with better particle control in the range of 10-75 microns (not less than 10 micron), free from any impurities would help in getting better mud properties at elevated temperature and will reduce the tendency of sag formation.
- Use of weighing materials of higher sp.gr e.g. Manganese Tetra oxide or Hematite would help in reducing solid percent in mud and thus improvement in rheology.
- Use of drilling mud coolers is necessary to cool the returning mud in flow line for safety of crew and to avoid production of excessive vapours and temperature near mud tanks (This cooling of mud will indirectly help in hole stability also).
- Sequence of mixing of chemicals for preparation of HPHT mud formulation.
  1) Take required quantity of pre hydrated Bentonite suspension in tanks. Mix barite and load up to desired sp.gr .Raise pH up to 10.5 and mix lignite and Sulphonated asphalt. After proper mixing then add HPHT fluid loss control polymer and mix for at least two hours at high shear rate. Mix HPHT Deflocculant.
  2) Initially this mud has high viscosity but once it is circulated at higher temperature, it will attain good rheology and fluid loss properties.

Tabulation

Table 1

Formulation : Bentonite suspension 4 cp + Barite Sp. Gr. 2.03 + pH 10.5 with caustic soda + Lignite 1.50% + SA 2%

	600	300	200	100	6	3	AV	PV	YP	API F/L (ml)	HPHT F/L (ml)
BHR	54	39	36	32	29	25	27	15	24		
AHR at 225 °C.	Very viscous, rheology could not be measured									34	105

Table 2

Formulation : Bentonite suspension 4 cp + Barite Sp. Gr. 2.10 + pH 9.03 with caustic soda + 1.25% HPHT fluid loss control polymer + 0.5% HPHT Deflocculant

	600	300	200	100	6	3	AV	PV	YP	HPHT F/L (ml)
BHR	Off Scale	Off Scale	268	176	42	32				
AHR at 225 °C	194	117	88	53	8	5	97	77	40	58

Table 3

Formulation: Bentonite suspension 20 cp + Barite Sp. Gr. 1.20 + pH 9 + 1.25% HPHT fluid loss control polymer

	600	300	200	100	6	3	AV	PV	YP	HPHT F/L (ml)
BHR	249	205	189	165	120	115	124.5	44	161	
AHR at 225 °C	76	49	39	25	6	4	38	27	22	46

Table 4

Formulation : Bentonite suspension 4 cp + Barite Sp. Gr. 2.07 + pH 9.6 with caustic soda + 1.5% lignite + 2% SA + 1.5% HPHT fluid loss control polymer + 0.5% HPHT Deflocculant

	600	300	200	100	6	3	AV	PV	YP	API F/L (ml)	HPHT F/L (ml)
BHR	Off Scale	Off Scale									
AHR at 225 °C	233	146	113	71	20	17	116.5	87	59	5.6	18

Table 5

Formulation : Bentonite suspension 4 cp + Barite Sp. Gr. 2.03 + pH 10.5 with caustic soda + 1.5% lignite + 2% SA + 1.5% HPHT fluid loss control polymer + 0.5% HPHT Deflocculant

	600	300	200	100	6	3	AV	PV	YP	API F/L (ml)	HPHT F/L (ml)
BHR	241	152	116	73	12	8	120.5	89	63		
AHR at 225 °C	138	83	61	36	6	4	69	55	28	4.8	18

Table 6

Formulation: Bentonite suspension 4 cp + Barite Sp. Gr. 2.10 + pH 10.5 with caustic soda + 1.5% lignite + 2% SA + 1.5% HPHT fluid loss control polymer

	600	300	200	100	6	3	AV	PV	YP	API F/L (ml)	HPHT F/L (ml)
BHR	Out	of	Scale								
AHR at 225 °C	212	123	90	51	5	3	106	89	34	5.6	30

Table 7

Formulation: Bentonite suspension 4 cp + Barite Sp. Gr. 2.01 + pH 10.5 with caustic soda + 1.5% lignite + 2% SA + 1.5% HPHT fluid loss control polymer

	600	300	200	100	6	3	AV	PV	YP	API F/L (ml)	HPHT F/L (ml)
BHR	240	145	111	70	17	13	120	95	50		
AHR at 175 °C	183	108	79	45	6	4	91.5	75	33	5.6	19.4

Table 8

Formulation : Bentonite suspension 4 cp + Barite Sp. Gr. 2.03 + pH 10.5 with caustic soda + 1.5% lignite + 2% SA + 1.5% HPHT fluid loss control polymer + 0.1% HPHT Deflocculant

	600	300	200	100	6	3	AV	PV	YP	API F/L (ml)	HPHT F/L (ml)
BHR	220	138	105	65	11	8	110	82	56		
AHR at 175 °C	230	144	121	76	12	9	115	86	58	5.8	20

Table 9

Formulation : Bentonite suspension 4 cp + Barite Sp. Gr. 2.03 + pH 10.5 with caustic soda + 1.5% lignite + 2% SA + 1.5% HPHT fluid loss control polymer + 0.1% HPHT Deflocculant

	600	300	200	100	6	3	AV	PV	YP	API F/L (ml)	HPHT F/L (ml)
BHR	247	154	117	73	12	8	123.5	93	61		
AHR at 225 °C	178	106	79	44	5	3	89	72	34	3.8	32

Table 10

Formulation : Bentonite suspension 4 cp + Barite Sp. Gr. 2.03 + pH 10.5 with caustic soda + 1.5% lignite + 2% SA + 1.5% HPHT fluid loss control polymer + 0.5% HPHT Deflocculant

	600	300	200	100	6	3	AV	PV	YP	API F/L (ml)	HPHT F/L (ml)
BHR	224	140	108	68	12	8	112	84	56		
AHR at 225 °C	136	82	61	36	6	4	68	54	28	4.8	18

Abbreviations

AV	:	Apparent Viscosity (cp)
PV	:	Plastic Viscosity (cp)
YP	:	Yield point (lbs/100 ft^2)
Gel_0	:	Gelation at 0 time (lbs/100 ft^2)
Gel_{10}	:	Gelation after 10 min. (lbs/100 ft^2)
Sp. Gr	:	Specific Gravity
F/L	:	Filtration Loss (ml)
PBS	:	Pre hydrated Bentonite suspension
SA	:	Sulphonated Asphalt
cp	:	Centipoise
AHR	:	after hot roll
BHR	:	Before hot roll
HPHT	:	High pressure high temperature

CHAPTER-8

CONCLUSION

Drilling in HPHT Wells has always been a formidable drilling challenge. Since the rigs and the down hole equipments used are expensive, drilling these high pressure and temperature wells require adequate knowledge and proper technology to make drilling economical.

Based on my study on the properties and characteristics of Drilling mud in the laboratory at IDT, it is observed that the oil based mud prepared for HPHT Wells should possess superior temperature stability, rheology, drilling performance and improved hole stability.

Hence accurate knowledge of drilling fluid behavior under actual conditions is required to maximize operational efficiency and to minimize cost and drilling fluid related risks (lost circulation, well kicks, and blow outs) on extreme high pressure / high temperature (HPHT) Wells

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