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Comparative Study of Using Oil-Based Mud Versus Water-Based Mud in HPHT Fields

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Abstract

Growing demand for oil and gas is driving the exploration and production industry to look for new resources in unexplored areas, and in deeper formations. According to the Bureau of Ocean Energy Management, Regulation and Enforcement, former Minerals Management Service (MMS), over 50% of proven oil and gas reserves in the United States lie below 14,000 ft. subsea. In the Gulf of Mexico some wells were drilled at 27,000 ft below seabed with reservoir temperatures above 400 °F and reservoir pressures of 24,500 psi. As we drill into deeper formations we will experience higher pressures and temperatures.

Drilling into deeper formation requires drilling fluids that withstand higher temperatures and pressures. The combined pressure-temperature effect on drilling fluid's rheology is complex. This provides a wide range of difficult challenges and mechanical issues. This can have negative impact on rheological properties when exposed to high pressure high temperature (HPHT) condition and contaminated with other minerals, which are common in deep drilling. High Pressure and High Temperature (HPHT) wells have bottom hole temperatures of 300 °F (150 °C) and bottom hole pressures of 10,000 psi (69 MPa) or higher.

Water-Based mud (WBM) and Oil-Based mud (OBM) are the most common drilling fluids currently used and both have several characteristics that qualify them for HPHT purposes. This paper compares the different characteristics of WBM and OBM to help decide the most suitable mud type for HPHT drilling by considering mud properties through several laboratory tests to generate some engineering guidelines. The tests were formulated at temperatures from 100 °F up to 600 °F and pressures from 5,000 psi to 25,000 psi. The comparison will mainly consider the rheological properties of the two mud types of mud and will also take into account the environmental feasibility of using them.

Key words: Oil-based mud; Water-based mud; HPHT fields

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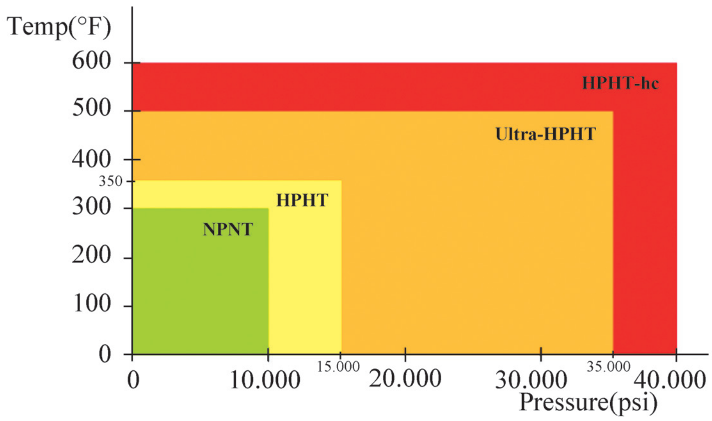
INTRODUCTION

Drilling fluids are usually formulated to meet certain properties to enable it to carry out the basic intended functions. The most prevalent problem affecting the drilling fluids in HPHT conditions, is the potential destruction of the mud properties under such elevated pressures and temperatures. Hence it requires a proper balance of mud properties to avoid oil and gas surge, kicks, formation damage and other drilling hazards associated with HPHT oil & gas wells.

For HPHT operations both Water-Based mud and Oil-Base mud have been used, however, in reality Oil-Based are more widely used to overcome problems in HPHT conditions. A drilling fluid must have the ability to drill formation where the bottom hole temperatures are excessively high, and especially in the presence of contaminants. Oil-Based muds can be formulated to withstand high temperatures over long periods of time, however, Water-Based mud can break down and lead to loss of viscosity and fluid loss control. Some other advantages of the application of Oil-Based mud are shale stability, faster penetration rates, providing better gauge hole and not to leach out salt. Native state coring fluid, longer term stable packer fluids (under high temperature conditions), high lubricity specially in high deviated and horizontal wells which could lead to reduce the risk of differential sticking and ability to drill low pore pressure formations are some of the factors to consider when choosing Oil-Based mud. Oil-Based mud offer exceptional corrosion protection and it is well suited to be used over and over also could be stored for longer periods of time.

It should be mentioned that Oil-Based mud is not always feasible. The initial cost of Oil-Based mud is high, especially those formulations based on mineral or synthetic fluids. Sometimes this high cost can be offset by Oil-Based mud buy-back program offered by service companies. Kick detection is more challenging when using Oil-Based mud compared to that of Water-Based mud. This is due to high gas solubility in Oil-Based mud. Lost circulation is also very costly for OBM operations.

Greater emphasis is also placed on environmental concerns when using Oil-Based mud as related to discharge of cuttings, loss of whole mud and disposal of the Oil-Based mud. Special precautions should be taken to avoid skin contact with OBM which may promote allergic reactions inhalation of fumes from Oil-Based mud can be irritating. Oil-Based mud can be damaging to the rubber parts of the circulating system and preclude the use of special oil resistant rubber. It has posed potential fire hazards due to low flash points of vapors coming off the oil. Additional rig equipment and modifications are necessary to minimize the loss of Oil-Based mud. In the past HPHT was attributed to any condition with pressure or temperature above the atmospheric condition. Service companies, operators, cement/drilling fluid testing equipment companies and other pipe or tools manufacturers, each, came up with a slightly different definition for HPHT condition (Shadravan, 2012). Figure 1 shows one of the most common definitions for HPHT tiers.



NPNT	=	Normal Pressure Normal Temperature;
HPHT	=	High Pressure High Temperature;
Ultra-HPHT	=	Ultra High Pressure High Temperature;
HPHT-hc	=	High Pressure High Temperature hors categorie.

Figure 1
HPHT Tiers (Shadravan, 2012)

Electric logging must be modified for use in Oil-Based mud since Oil-Based mud is non-conductive therefore resistivity measuring logs will not work in Oil-Based mud such as SP and resistivity logs. Oil-based muds require emulsifiers that are very powerful oil-wetting materials, which can also change the wettability of the rock to an oil-wet condition. Most of the time Oil-Based mud is more compressible than water mud, and, therefore, the downhole density may vary considerably from that measured at the surface. Circulating mud behaves as a countercurrent heat exchanger. The rate of heat exchange between the mud, the casings and the formation at any particular depth depends on the temperature, thermal conductivity and specific heat capacity of the materials and on the velocity of the mud. In the presence of casing, vertical conduction of heat further complicates the temperature distribution. In the absence of enough circulation, gravity may cause weighting material (e.g. barite) to settle, resulting in density segregation or sagging. In deviated wells, sagging may result in a barite bed on the low side of the hole. Depending on the wellbore angle and the strength of the bed, the barite beds can slump down the low side of wellbores like an avalanche. The movement of the solids in the drilling fluid during sagging may result in a lowering of the viscosity by shear thinning, accelerating the process. Ultimately, slumping may result in barite accumulation and a pronounced density change within the drilling fluid (Adamson *et al*., 1998). The rheological and filtration loss characteristics of colloidal gas Aphron have been investigated before (Shahri, 2012). Most of the HPHT Rheometers rely on an ideal "frictionless" pivot and jewel design to provide the readings, the ideal condition may not be met especially when the test can be affected by quite a few factors including temperature, pressure, solids content, type of solids and time of usage. This certainly can impact the quality of the data generated under the maximum capacity of the instrument (Lee, Shadravan & Young, 2012).

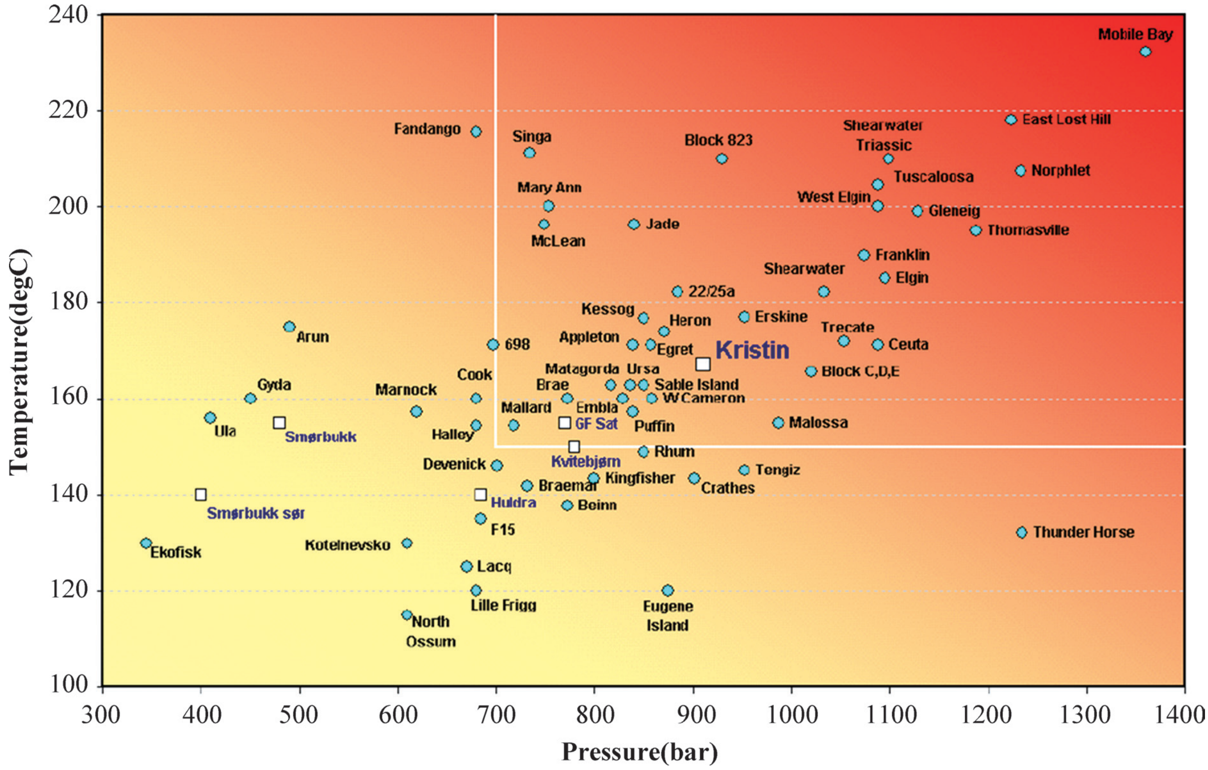


Figure 2
Some of HPHT Fields Around the World

1. RHEOLOGICAL PROPERTIES OF WATER-BASED MUD VERSUS OIL-BASED MUD

Amani and Al-Jubouri conducted two separates studies on the rheological properties of an OBM sample (12.5 ppg) and a WBM sample (8.6 ppg) under HPHT conditions using the state-of-art Chandler 7600 HPHT viscometer (Figure 3). This viscometer was capable of measuring the rheological properties of drilling fluids under high temperatures up to 600 °F and high pressure up to 40,000 psi (Amani & Al-Jubouri, 2012).

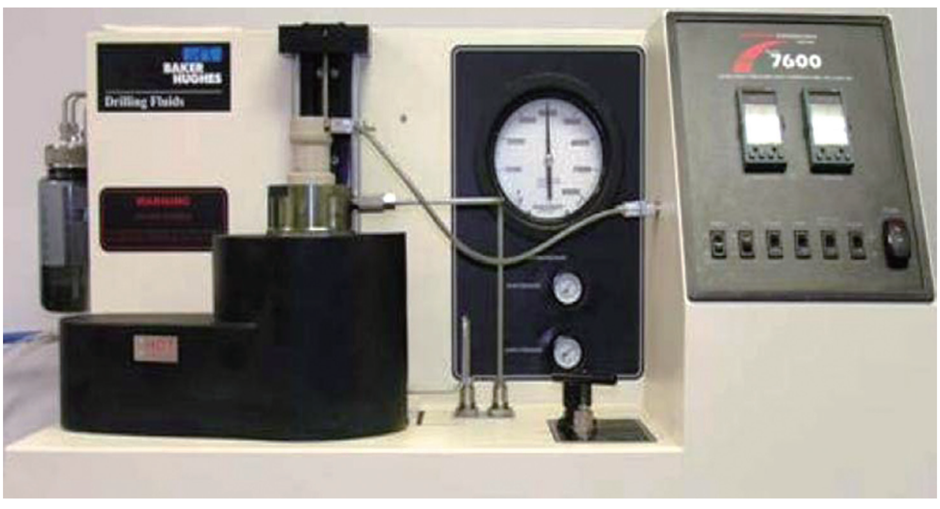


Figure 3
Chandler 7600, Extreme HPHT Viscometer

The samples were standard industrial types drilling fluids commonly used in the fields. Table 1 and Table 2 show the properties of these two mud samples.

Table 1
Properties of the Oil-Based Mud Sample Used in the Study

Fluid formulation	
LVT-200, bbl	155.47
Versagel HT, ppb	5.0
Lime, ppb	8.0
VersaMul, ppb	9.0
VersaCoat HF, ppb	3.0
Water, bbl	63.64
$CaCl_2$, ppb	22.37
VersaTrol, ppb	6.0
VersaMod, ppb	0.25
M-I Bar, ppb	251.91
Mud properties	
Mud Weight, ppg	12.5
OWR	75/25
Rheo Temp, ^{o}F	150
600 RPM	76
300 RPM	51
200 RPM	42
100 RPM	31
6 RPM	17
3 RPM	16
PV, cps	25
YP, lbs/100 ft^2	26
10 Sec. Gel	23
10 Min. Gel	33
E.S., Vts @ 120 ^{o}F	718

Table 2
Properties of the Water-Based Mud Sample Used in the Study

Mud properties	
Sample From	ACTIVE
Time Sample Taken	19:00
Flowing temp (^{o}F)	144
Depth (ft)	10392
TVD (ft)	6250
Mud weight (ppg)	8.6
Funnel Viscosity (sec/qt)	38
Temp. for PV (^{o}F)	120
Plastic Viscosity (cp)	5
Yield Point (lbf/100 ft^2)	15
Gel Strength (10 sec)(lbf/100 ft^2)	4
Gel Strength (10 min)(lbf/100 ft^2)	5
Gel Strength (30 min)(lbf/100 ft^2)	6
API Filtrate (ml/30 min)	4.6
Cake Thickness API (1/32 in)	0.5
Solids Content (%)	2.5
Oil Content (%)	1
Water Content (%)	96.5
Sand Content (%)	0.1
MBT Capacity (lb/bbl)	0.5
pH	9.2
Mud Alkalanity (Pm)(ml N50 H_2SO_4)	0.44

To be continued

Continued

Mud properties	
Filitrate Alkalanity (Pf)(ml N50 H_2SO_4)	0.19
Filtrate Alkalanity (Mf)(ml N50 H_2SO_4)	0.74
Calcium (mg/L)	720
Chlorides (mg/L)	9000
Total Hardness (mg/L)	860
Excess lime (lb/bbl)	0.01
K+ (mg/L)	-
Make up water Chlorides (mg/L)	7000
Solids adjusted for salt (%)	1.64
SO_3 (ppm)	10

2. MATRIX OF EXPERIMENTS

Table 3 shows the matrix of the experiments that were performed on the two mud samples. The mud samples were tested for a range of pressures and temperatures in order to determine their effect on the different rheological parameters.

Table 3
Experiments Matrix

Run #	Sample	Pressure (psi)	Temperature Range (^{o}F)
1	OBM	5000	70-550
2	-	10000	70-550
3	-	15000	70-550
4	-	20000	70-550
5	-	25000	70-550
6	-	30000	70-550
7	-	35000	70-550
8	WBM	5000	70-500
9	-	15000	70-500
10	-	25000	70-500
11	-	35000	70-500

The results of the experiments led to the following observations:

2.1 Viscosity

Viscosity as the representation of a fluid's internal resistance to flow, defined as the ratio of shear stress to shear rate. Viscosity is expressed in poise.

$$\mu = \frac{\text{Shear stress}}{\text{Shear rate}} = \tau / \gamma$$

As previously defined:

$$\mu = \frac{\text{Dyne.sec}}{\text{cm}^2} \text{(defined as poise)}$$

A poise is a very large number and therefore, viscosity is typically reported in centipoise (100 centipoise = 1 poise).

Figure 4 compares the dial reading values (which correspond to the viscosity) for the Oil-Based and the Water-Based mud samples at different temperatures and for two different pressures (5000 psi and 25000 psi). The plots shows that the viscosity of the sample slightly increases as pressure increases (directly proportional) and decreases as temperature increases (inversely proportional) for both samples. Generally, the Oil-Based mud sample expresses higher dial readings (viscosity) than the Water-Based sample. The plots, however, show that the mud samples have experienced abrupt changes in their behavior at 250 °F for Water-Based mud sample and at 400 °F for the Oil-Based mud sample which is an indication of the failure of the two samples at these temperatures. Apparently, the Oil-Based sample showed more tolerance to high temperature than the Water-Based sample.

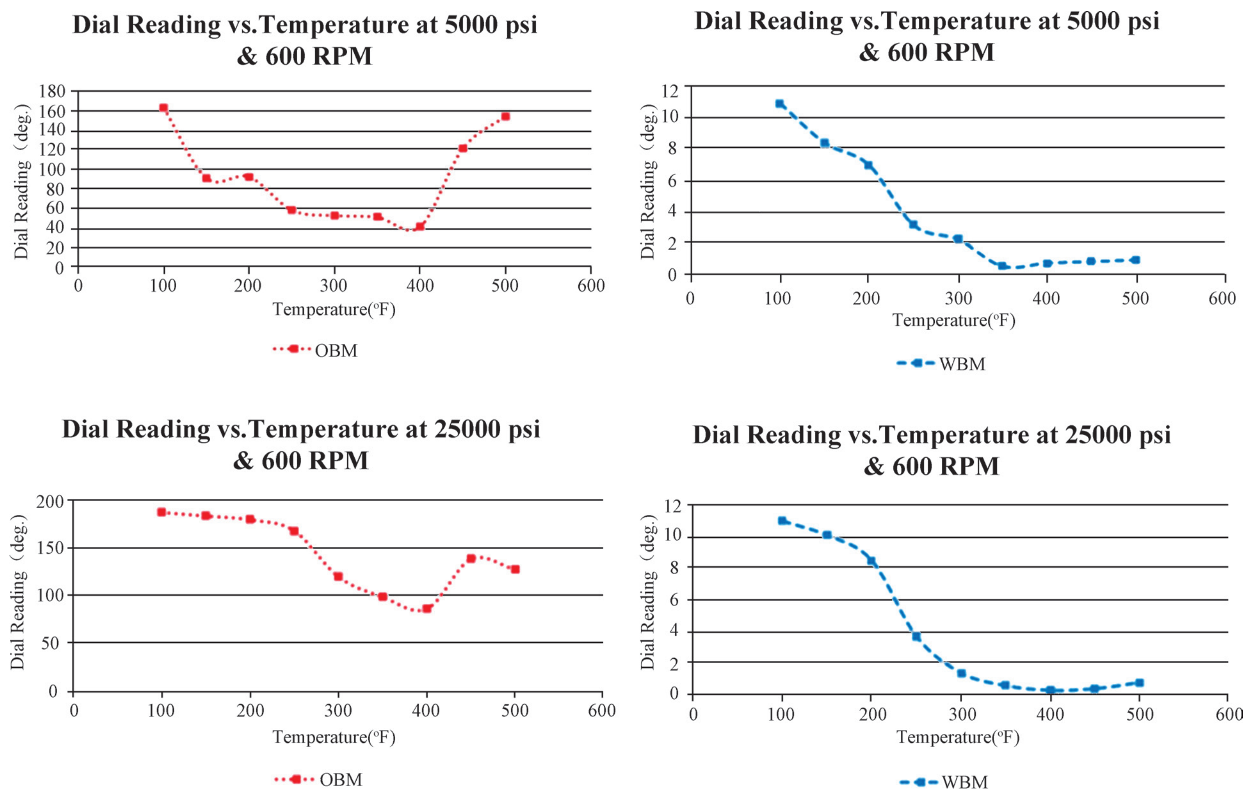


Figure 4
Dial Reading of the Two Mud Samples Versus Temperature for Two Different Pressures at 600 RPM

2.2 Yield Point

Yield Point (YP) as the initial resistance to flow caused by electrochemical forces between the particles is a parameter of the Bingham plastic model. It is the yield stress extrapolated to a shear rate of zero. A Bingham plastic fluid plots as a straight line on a shear rate (x-axis) versus shear stress (y-axis) plot, in which Yield Point is the zero-shear-rate intercept. Plastic Viscosity (PV) is the slope of this line. Yield Point is calculated from 300 and 600 RPM viscometer dial readings by subtracting PV from the 300 RPM dial reading. Yield point is dependent upon the surface properties of the mud solids also the volume concentration of the solids. Yield Point could be used to evaluate the ability of a mud to lift cuttings out of the annulus. A high Yield Point implies a non-Newtonian fluid, one that carries cuttings better than a fluid of similar density but lower Yield Point. Yield Point can be controlled by proper chemical treatment. As the attractive forces are reduced by the chemical treatment, the Yield Point will decrease. It is lowered by adding deflocculant to a clay-based mud and increased by adding freshly dispersed clay or a flocculant, such as lime.

For a Bingham Plastic fluid, stress can be applied but it will not flow until a certain value, the yield stress, is reached. Beyond this point the flow rate increases steadily with increasing shear stress. This is roughly the way in which Bingham presented his observation, in an experimental study of paints. These properties allow a Bingham plastic to have a textured surface with peaks and ridges instead of a featureless surface like a Newtonian fluid.

Yield Point (YP) is calculated from VG measurements as follows:

$$YP = \theta_{300} - (\theta_{600} - \theta_{300})$$

or

$$YP = \theta_{300} - PV$$

The limitation of the Bingham plastic model is that most drilling fluids, being pseudoplastic, exhibit an actual yield stress which is considerably less than calculated Bingham yield point. This error exists because the Bingham plastic parameters are calculated using a VG meter at 600 RPM (1022 sec-1) and 300 RPM (511 sec-1).

Figure 5 shows the yield point values for the two mud samples with temperature for different pressures at 600 RPM. Similar to viscosity, yield point's plot for both mud samples shows that it is generally higher at low temperatures and high pressures. Also, the plots indicate that the Water-Based sample and the Oil-Based mud sample failed at temperatures of 250 °F and 400 °F respectively. The yield point for the Oil-Based mud was much higher than the values for the Water-Based mud sample is a desired quality in the drilling.

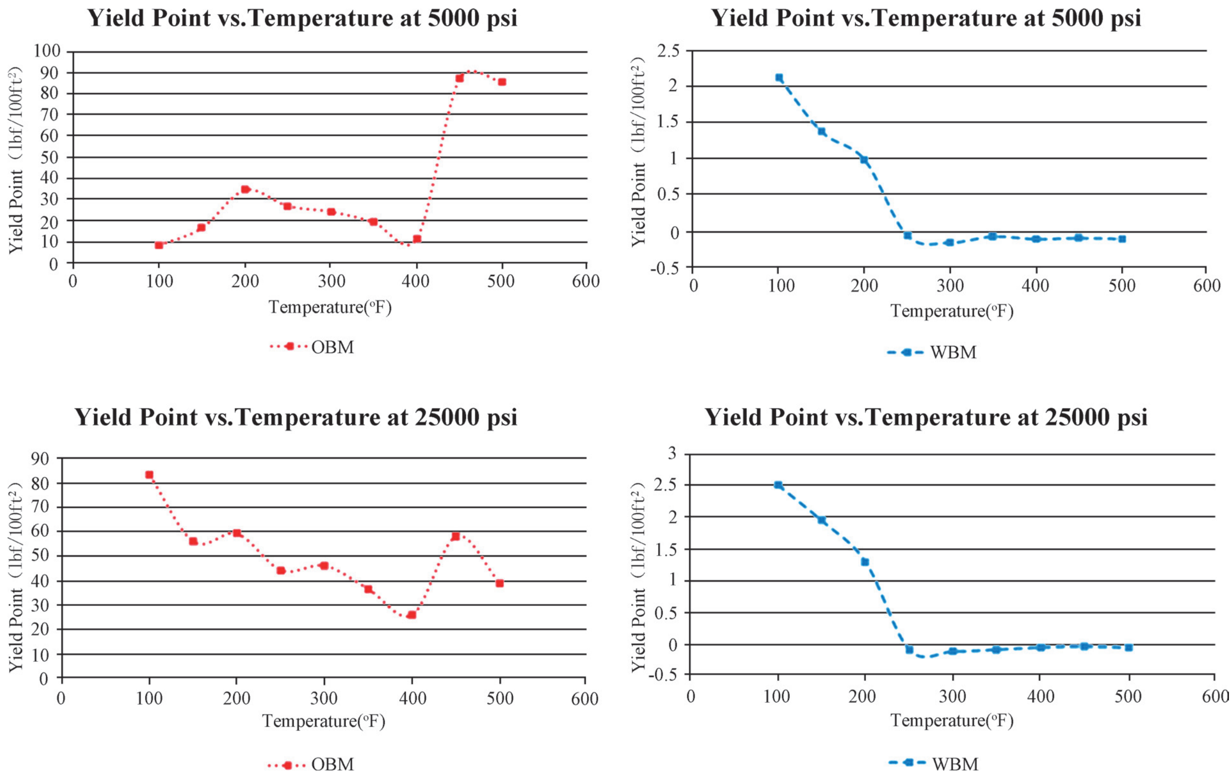


Figure 5
Yield Point Values Versus Temperature for Different Pressures

2.3 Gel Strength

Gel Strength is the shear stress measured at low shear rate after a mud has set quiescently for a period of time (10-seconds and 10-minutes in the standard API procedure, although measurements after 30-minutes or 16-hours may also be made), it indicates strength of attractive forces (gelation) in a drilling fluid under static conditions. Excessive gelation is caused by high solids concentration leading to flocculation.

Signs of rheological trouble in a mud system often are reflected by a mud's gel strength development with time. When there is a wide range between the initial and 10-minute gel readings they are called "progressive gels". This is not a desirable situation. If initial and 10-minute gels are both high, with no appreciable difference in the two, these are "high-flat gels", also undesirable. The magnitude of gelation with time is a key factor in the performance of the drilling fluid. Excessive gel strengths can cause:

- Swabbing, when pipe is pulled,
- Surging, when pipe is lowered,
- Difficulty in getting logging tools to bottom,
- Retaining of entrapped air or gas in the mud,
- Retaining of sand and cuttings while drilling.

Gel strengths and yield point are both a measure of the attractive forces in a mud system. A decrease in one usually results in a decrease in the other; therefore, similar chemical treatments are used to modify them both. The 10-second gel reading more closely approximates the true yield stress in most drilling fluid systems. Water dilution can be effective in lowering gel strengths, especially when solids are high in the mud.

Figure 6 shows that the 10-sec gel strength for the Oil-Based mud sample was higher at low and high pressure. The gel strength for the Water-Based mud reached minimal values (almost zero gel strength) at 250 °F while the Oil-Based mud was more enduring to high temperatures up to 400 °F at which its gel strength sharply dropped.

2.4 Failure Temperature

Circulating drilling fluid and moving along the well gains or loses heat from or to its surroundings. The rate of heat exchange depends on the temperature and velocity of the fluid, the thermal conductivity of the formation, the geothermal gradient in the undisturbed reservoir, the specific heat capacity of the mud and other factors. In the presence of casing strings, significant vertical conduction of heat further complicates the temperature profile. There is a net transfer of heat from the formation to the mud as it goes down the well. On reaching the bit, the mud is still cooler than the surrounding formation. The mud continues to heat up as it returns to surface until it reaches a depth where

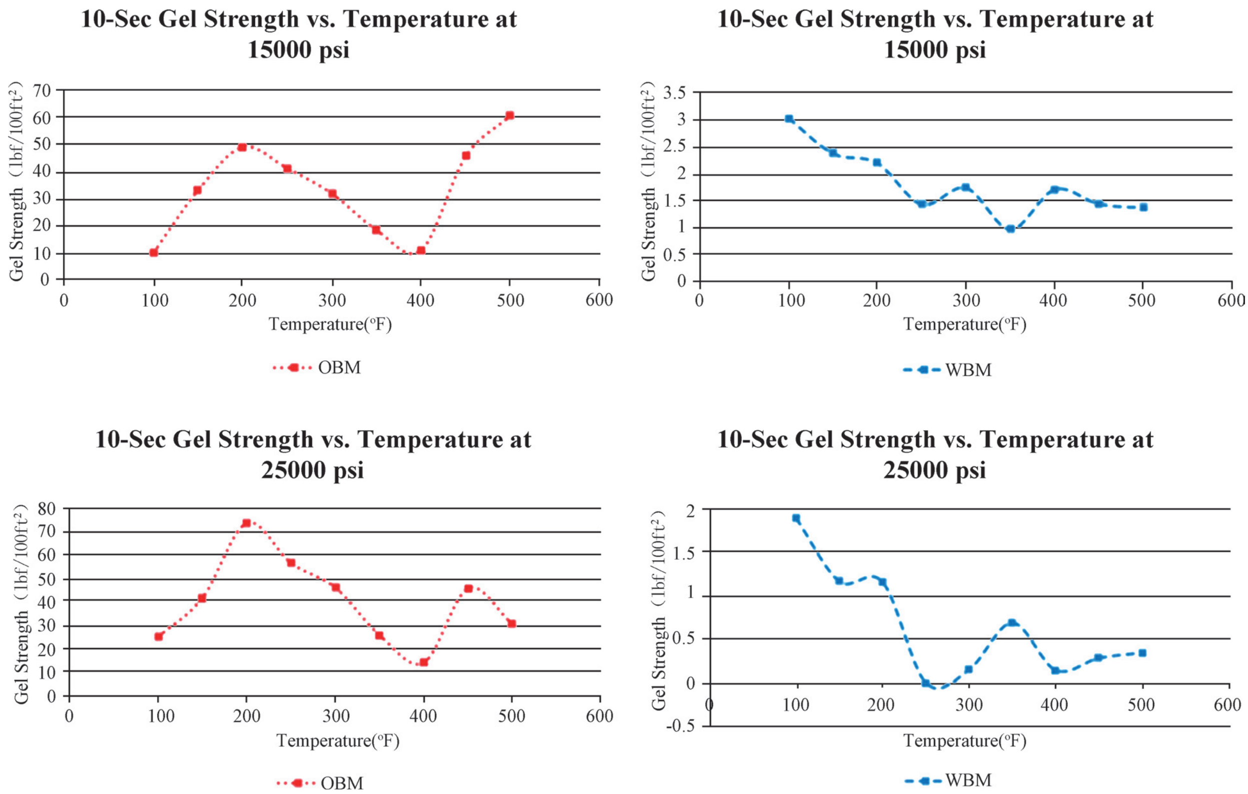


Figure 6
10-Sec Gel Strength Values Versus Temperature for Different Pressures

the formation temperature equals the mud temperature. Above this depth, the mud cools on its way to surface. Steady-state temperature profiles can be computed once a satisfactory model has been developed. With time, thermal equilibrium can be achieved in two ways after circulation has ceased or under constant circulating conditions. The static steady-state profile approaches the geothermal gradient, while the circulating temperature profile will vary with pump rate (Adamson *et al*., 1998).

An oil base fluid can be defined as a drilling fluid which has oil as its continuous or external phase and the water, if present, is the dispersed or internal phase. The solids in an oil base fluid are oil wet, all additives are oil dispersible and the filtrate of the mud is oil. The water, if present, is emulsified in the oil phase. There are two basic classifications of oil-based fluids; invert emulsions and all-oil muds. The amount of water present will describe the type of oil base fluid. The oil used in these types of oil base fluids can range from crude oil, refined oils such as diesel or mineral oils, or the non-petroleum organic fluids that are currently available. The latter type fluids-variously called inert fluids, pseudo oils and synthetic fluids are now considered more environmentally acceptable than diesel or mineral oils.

Conventional all-oil muds have oil as the external phase but they are designed to be free of water when formulated or in use. Since water is not present, asphaltic type materials are required to control the fluid loss and viscosity. Since there is no water added to this system during the formulation and water additions are avoided if possible while drilling, there is only a minimum requirement for emulsifiers. All-oil muds can withstand small quantities of water; however, if the water becomes a contaminating effect, the mud should be converted to an invert emulsion. If the water is not quickly emulsified, the solids in the mud can become water wet and will cause stability problems. The water wet solids will blind the shaker screens and loss of whole mud will occur.

Invert emulsions are oil muds that are formulated to contain moderate to high concentrations of water. Water is an integral part of the invert emulsion and can contain a salt such as calcium or sodium chloride. An invert emulsion can contain as much as 60% of the liquid phase as water. Special emulsifiers are added to tightly emulsify the water as the internal phase and prevent the water from breaking out and coalescing into larger water droplets. These water droplets, if not tightly emulsified, can water wet the already oil wet solids and seriously affect the emulsion stability. Special lignite derivatives or asphaltites are used as the fluid loss control agents, and bentonite derivatives are used to increase the viscosity and suspension properties of the system. Invert emulsions are usually tightly emulsified, low fluid loss oil muds. An improvement in drilling rates has been seen when the fluid loss control of the system is relaxed, thus the name “relaxed” invert emulsion. Also, the relaxed invert emulsions fluids do not use as much emulsifier as the regular invert emulsion systems.

Failure temperature at a specified pressure is the temperature at which the rheological parameters of the drilling fluid, such as viscosity, yield point and gel strength, will reduce dramatically resulting in significant reduction in the fluid's ability to convey the drilling cuts. Figure 7 shows the variation in rheological profile with the time of the experiment for the Oil-Based mud sample based on dial readings changes with temperature and pressure. The active line represents the dial reading of the drilling fluid. The dot-dashed and dotted lines are respectively showing the temperature of the sample being tested and applied pressure. Dial readings (active line) are shown in repeated cycles of different RPM values (600, 300, 200, 100, 6 and 3 RPM) with higher RPM values corresponding to longer spikes.

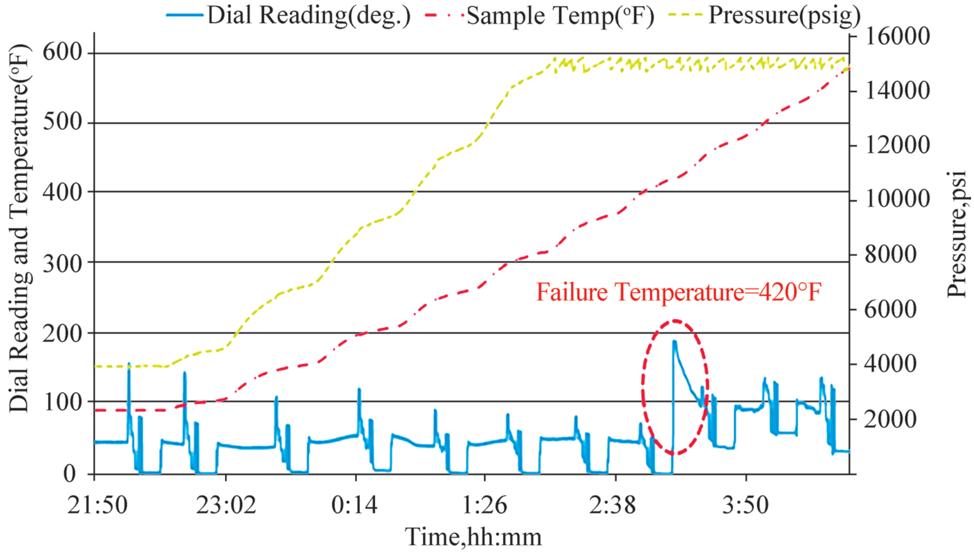


Figure 7
Failure Temperature Calculation Based on Rheology Tests for 12.5 ppg OBM Sample

The plot shows that the rheological profile (represented by dial reading) was gradually decreasing as temperature increased which suggests that the mud sample was thermally degrading until a temperature of 420 °F at which erratic readings of dial reading that is inconsistent with the rheological profile were observed. This suggests that this conventional Oil-Based sample failed at this specific temperature.

Similarly, Figure 8 shows the variation in rheological profile with respect to time of the experiment for the WBM sample. This plot also shows that the rheological profile was gradually decreasing as temperature increased and suggests that the mud sample was thermally degrading until a temperature of 250 °F after which erratic readings of dial readings inconsistent with the rheological profile were observed; in other words, the mud sample failed at this specific temperature.

Based on the results of the two samples, 12.5 ppg OBM sample and 8.6 ppg WBM sample, it shows Oil-Based mud (OBM) is more effective than the Water-Based Mud (WBM) due to its thermal stability. It is clearly shown that the Oil-Based mud sample can be used at temperatures approaching 420 °F while the Water-Based Mud started to have erratic readings on 250 °F.

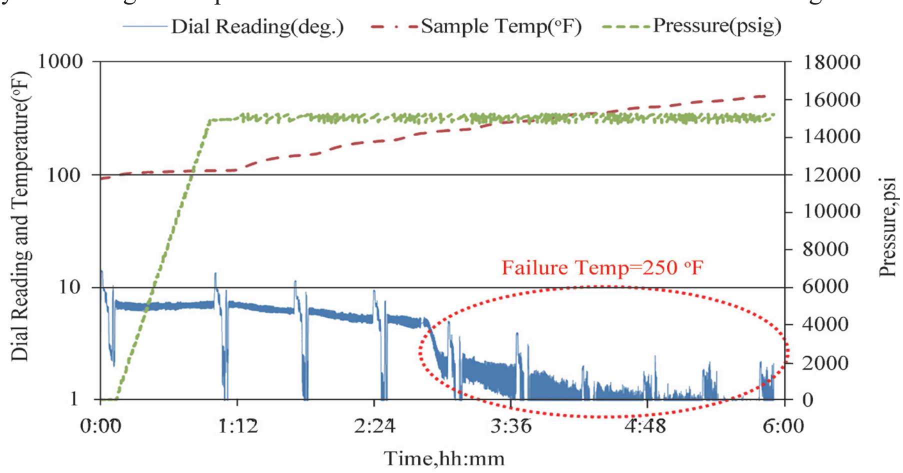


Figure 8
Failure Temperature Calculation Based on Rheology Tests for 8.6 ppg WBM Sample

3. ENVIRONMENTAL CONSIDERATION IN USING OBM AND WBM FOR HPHT DRILLING

Oil-Based mud may be selected for special applications such as high temperature or high pressure wells, minimizing formation damage and other reason for choosing Oil-Based fluids is that they are resistant to contaminants such as anhydrite, salt, and CO_2 and H_2S acid gases. Oil-Based mud is effective against all types of corrosion and has superior lubricating characteristics, and sometimes it even permits mud densities as low as 7.5 lb/gal.

Cost can be one of the concerns when selecting Oil-Based muds. Initially, the cost per barrel of an Oil-Based mud is very high compared to a conventional Water-Based mud system. However, because Oil-Based mud can be reconditioned and reused, the costs on a multi-well program may be comparable to using Water-Based fluids. Also, buy-back policies for used Oil-Based mud can make them an attractive alternative in situations where the uses of Water-Based mud prohibit the successful drilling and/or completion of a well.

Today, with increasing environmental concerns, the use of Oil-Based mud is either prohibited or severely restricted in many countries. Environmental regulations restrict and prohibit the use of drilling fluids that have the potential to pollute the soil and ground water aquifers. Oil-Based drilling fluids are thus prohibited in many countries around the globe such as the USA, United Kingdom, Holland, Norway, Nigeria, European countries, Saudi Arabia, and Qatar. In some areas, drilling with Oil-Based fluids requires the used mud and cuttings to be contained and hauled to an approved disposal site. Discharges of cuttings from water-based or oil-based mud drilling operations can have an adverse effect on the seabed biological habitat in the immediate vicinity of the platform, and this is due mainly to physical burial of the natural sediment. The spread of cuttings particles is greatly influenced by their particle size and the prevailing current regime. However, it is believed that cuttings, particularly from oil-based mud drilling operations, fall more directly to the seabed as a result of agglomeration.

The extent of biological effect is greater from oil-based mud cuttings than from water-based mud cuttings. Beyond the area of physical smothering, the effects of oil-based mud cuttings may be due to organic enrichment of the sediment and/or the toxicity of certain fractions of the oils used, such as aromatic hydrocarbons. It has not been possible from the data available at present to distinguish between the ecological effects of diesel mud and alternative base muds. As more data on the effects of the use of alternative muds become available it may be possible to elaborate on this issue. Despite the scale of inputs, in all fields studied, the major deleterious biological effects were confined within a 500 meter radius and associated primarily with burial under the mound of cuttings on the seabed. Seabed recovery in this zone is likely to be a long process.

Surrounding the area of major impact is a transition zone in which more subtle biological effects can be detected as community parameters return to normal, generally within 200-1,000 meters. The shape and extent of this zone is variable, and is largely determined by the current regime and the scope of the drilling operation. In areas with stronger bottom currents and more extensive drilling, this zone may be extended to 2,000 meters in the direction of greatest water movement. From the little information which is available, the surface sediments studied in this zone appeared to be aerobic and bio-degradation of hydrocarbons seems to be taking place. Thus a more rapid recovery of the transition zone is expected on cessation of drilling.

The costs of containment, hauling, and disposal can greatly increase the cost of using Oil-Based fluids. Water-Based mud is less harmful to the environment which makes it a preferred option for HPHT drilling in these countries. Water-Based mud with the same performance characteristics of invert emulsion drilling fluid is becoming available now which can have applications in HPHT condition. Chrome materials are not environmentally friendly and they are part of some high-temperature water-based fluids, acting as an efficient and stable dispersant and fluid loss control agents. New Chrome-free containing materials for high temperature and high pressure have been introduced in stable Water-Based drilling fluid system by using a combination of clay and synthetic polymer to provide a stable rheology and fluid loss. This calls for designing an HPHT tolerant Water-Based mud with an eco-friendly formulation.

CONCLUSIONS

High pressure and high temperature operations seem to be a new normal for oil and gas industry. Drilling into the reservoirs with elevated pressures and temperatures requires a fluid with stable rheological properties. This study shows that oil-based mud is more tolerant to high temperature/high pressure conditions. Moreover, the failure temperature for the oil-based mud is significantly higher than that of water-based mud sample. The oil-based mud sample used in this study maintained the desired rheological parameters at high temperatures, up to 400 °F.

Oil-based mud is a proper choice for most of the HPHT applications if not violating the environmental regulations. Designing an eco-friendly water-based mud is a necessity for HPHT drilling. A new environmentally safe water based polymer system has been tested for drilling application with temperatures up to 232°C (450 °F). The system components are newly developed synthetic polymers that do not contain chromium or other environmentally harmful materials.

Water-based offers a more environmental friendly choice yet some of additives that are used to enhance its performance at HPHT conditions, such as Chrome-Lignosulfonates, can be harmful and a source of pollution, thus it is necessary to develop new formulas for HPHT Water-Based muds that could act like Oil-Based mud but cause less harm to the environment.

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