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Shale Organic Matter Interaction in Non-Aqueous Drilling Fluids

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Abstract

Pad drilling and rig mobility have led to a much-improved drilling efficiency in U.S. shale plays. The average drilling time per well has been reduced by approximately 50%, while the drilling fluids solids control equipment and technology lag in efficient and effective removal of solids. One noticeable consequence is the accumulation of low gravity solids (LGS) in non-aqueous drilling fluids, which has increased from 5-10% to 10-15% on average. To improve the operational efficiency, it is critical to understand the effects of excessive drilled solids and organic matter buildup.

This systematic study is used to explain the drilling performance in formations in connection with organic matter and clay content.

Core samples from U.S. shale plays with various amounts of total organic carbon (TOC) were selected for a laboratory study. The formation samples were ground to fine particle size to investigate the effect of the interaction between fine solids and base fluid on drilling mud properties. A synthetic paraffin based mud (SBM) was selected for comparison to diesel oil based mud (OBM). It was found that the fine solids increased the OBM viscosity more significantly than with SBM. The accretion of shale solids to steel was also higher in OBM vs SBM. The OBM filter cake was seen to be 5 times more sticky than the SBM filtercake. More interestingly, the recovery of 5-10 mesh solids (2- 4 mm, representing simulated shale drilled cuttings) hot rolled in OBM was only 22-26 wt% while it was over 95 wt% in SBM.

The high solids recovery measured using the SBM system is interpreted to be attributed to the very low interaction of the SBM with organic matter and/or clay cuttings particles from the formation. The extremely small organic matter and/or clay particles are unable to be removed by the solids control system and remain suspended to circulate and build up in the borehole.

The study results suggest the use of SBM helps prevent the disintegration of cuttings thus maintaining the properties of the drilling fluid system.

Introduction

Oil based drilling fluids or muds (OBMs) made with diesel have been used broadly in the US since their introduction in the 1930’s (1) for their improved performance in lubrication and shale inhibition compared to water based drilling muds (WBMs). For environmental reasons, drilling fluids based on low toxicity mineral oil and synthetic oil evolved to replace diesel in environmentally sensitive areas such as the Gulf of Mexico. However, diesel OBM still dominates US land drilling for horizonal sections and is the most common mud used to drill long laterals because of its lower up-front unit cost for the base oil.

As lateral drilling technologies further mature, pad drilling has become the new normal. The use and reuse of the same fluid system to drill multiple laterals from the same pad has reduced the drilling time per well significantly; however, the challenge is the buildup of low gravity solids in OBM (2) as the solids removal efficiency is not keeping up with the trend. The presence of excessive low gravity solids has detrimental effects on drilling performance especially when the concentration exceeds 10 vol % of the mud. These solids also increase the cost to maintain the system. One direct effect is the increase in OBM viscosity and other rheological properties. Viscosity control has become the primary goal to maintain the fluid properties.

Although there are various rheological models to predict the properties of drilling fluids (3) and some of them consider the effect of solids percentage or draw a relationship between the solids content and viscosity, e.g., solids vs. plastic viscosity (PV), the effect of LGS is still difficult to predict. Not only the LGS content but also the particle size distribution (PSD) of the solids can affect the rheological properties significantly. The effects of LGS in the fluid are more evident at high loading (4) and the finer the solids the higher the viscosity. For instance, one study (5) showed a much higher viscosity with micronized barite than with regular API barite. During drilling, the low gravity solids entrained in the mud are ground finer over time and this results in a shift in PSD with a subsequent increase in surface area.

There have not been sufficient studies to quantify the impact and to understand the degradation of LGS as it is commonly believed that non-aqueous drilling fluid (NADF) does not interact with shale chemically. The change in rheology in OBM is thought to be mainly due to mechanical forces. Most of the studies on shale interaction are designed to test aqueous drilling fluids including shale accretion and dispersion tests (6,7). There are also examples in the literature of utilizing the accretion and dispersion methods to evaluate the performance of NADFs (8,9) such as ester based drilling fluids (10).

This paper provides a systematic study on the effect of shale solids on NADF and specifically compares the performance of an OBM to a SBM to quantify the chemical interaction between the base oil and the solids. More importantly, the goal is to study the effect of organic matter on the properties of drilling fluids. Organic matter exists in most shale formations (11) and therefore also occurs in most drilled cuttings (12). It is principally composed of kerogen. The TOC content is a measurement of the organic matter in shale including kerogen and other organic materials.

Methodology

Materials

Samples were obtained from U.S. shale formations and two samples (designated A and B) were selected and processed for the laboratory study. In addition to the total organic carbon content, the mineralogy was measured, as shown in Figure 1. Sample A had a high TOC of 17.9 wt% and a low clay content of 5.8 wt%. Sample B had a moderate 8.7 wt% TOC and a high clay content at 24.6 wt%.

The samples were ground and sized accordingly for fluid contamination, accretion and shale recovery tests.

A set of standard additives was selected to provide a baseline mud formulation that included emulsifier, $CaCl_2$ brine, lime and organoclay. A synthetic paraffin base oil manufactured from methane in a Gas-to-Liquid (GTL) process was selected for comparison to diesel in otherwise identical drilling muds.

Fluid formulation and Properties

The test matrix is shown in Table 1. The effect of the fines size degradation and buildup of organic matter on drilling mud rheology was determined with both shale samples. The accretion of particles to metal was measured after hot rolling the muds with 5-10 mesh shale particles simulating drilled cuttings. Sample B was used to study the change in fines particle size distribution over time, and the recovery of 10 mesh and coarser shale particles after hot rolling with 5-10 mesh simulated drilled cuttings.

Simplified and unweighted drilling fluid formulations were selected to minimize the effect of additives. The oil water ratio (OWR) was 70/30 v/v for testing with Shale A and it was lowered to 75/25 v/v with Shale B. In each round of tests, the SBM and OBM formulations were identical except for the base oil. OBM is based on #2 diesel, which is used on the majority of the rigs in U.S. land drilling. SBM is based on a synthetic paraffin base oil, which is also used in US onshore drilling for environmental and worker health benefits as it is virtually free of aromatics including BTEX. Due to the relatively pure chemical composition and linear structure of the carbon chains, the synthetic paraffin is highly non-polar.

The fluids were mixed and tested according to API RP13I standard procedures. The formulations shown in Tables 2 and 4 and were used to study the effects of shale A and B accordingly. The same lab equipment and procedures were used to mix both synthetic and diesel drilling fluids to make a valid comparison. The order of mixing is from base oil, emulsifier, organoclay, lime, calcium chloride brine to solids.

The rheological and filtration properties were measured before and after heat aging with an Ofite 900 viscometer at 150 °F and atmospheric pressure. The high temperature high pressure (HTHP) filtration test was conducted following the API RP 13I procedure at 250 °F with 500 psi differential pressure.

Shale and Filtrate Characterization

The shale samples were characterized using an Energy-Dispersive X-Ray Fluorescence (ED-XRF) Elemental and LECO carbon determinator and analyzer. The mineralogy and TOC were quantified and reported. The clay and TOC are critical to understanding the impact on drilling fluid properties and resultant drilling performance.

High resolution gas chromatography (GC) was used to characterize the filtrate of OBM and SBM and look for compositional changes.

Fine Solids Contamination

In the first round, pre-ground shale samples A and B solids were included in the mud formulations shown in Tables 2 and 4. The fine solids were added to simulate shale formation particles incorporated into the mud during the drilling process. They were obtained by pre-grinding sample A to a particle range between 80 and 100 mesh and sample B to a particle size range <100 microns.

For both shale samples A and B, after the fine solids were mixed into the OBM and SBM, the muds were heat aged by hot rolling them at 250 °F for 16 hours.

With shale sample B, it was decided to evaluate both the effect of fines contamination on mud rheology and also the change in fine particle size distribution before and after hot rolling. To accomplish this, the pre-ground shale B fine solids concentration was increased to 91.1 lb/bbl and the fine particle size range was widened to include everything less than 100 microns. The PSD of the fine solids from sample B was determined using a Malvern 3000 particle analyzer.

Shale Accretion

In the second round of tests, shale accretion was determined by hot rolling the OBM and SBM containing coarse shale particles that simulated drilled cuttings. There were no pre-ground fines added to the muds as was the case with the first round tests. The accretion test is normally used for determination of solids buildup on steel surfaces due to the interaction between shale and aqueous based drilling fluids. In this study it was applied to NADF to determine if the base oil type has an effect on the level of accretion.

The OBM or SBM containing the solids was placed in an aging cell. A solid stainless-steel bar with 1” diameter and 4” length was included in the cell to simulate the drilling process where shale solids are crushed by the drill pipe. The cells were hot rolled at 250°F for 3 days. After hot rolling, the amount of solids sticking to the steel bar was determined by subtracting the initial weight of the steel bar from the weight of the steel bar coated with drilling fluid and solids after 16 hours drying at 150 °F.

Shale Recovery

The disintegration of coarse shale particles was measured in the second round of tests for shale sample B only. After the accretion was measured, the fluid containing solids was carefully removed from the aging cell and run through a 10-mesh screen to determine the weight % recovery retained on the screen. After observing the amount of solids on the bar, it was determined that the weight of solids sticking to the bar was negligible compared to the weight of solids in the aging bombs. As such, there was not a need to scrape solids from the bar to add to the solids removed from aging cell. A field WBM sample was used for comparison of shale recovery with the OBM and SBM samples.

Results and Discussion

In addition to the API mud check, particle size distribution has become a standard analysis for drilling fluid testing in the U.S. as the drilled solids buildup and their effect on performance has been a concern. For instance, the weight percentage of solids less than 6 microns in size is a crucial factor to determine the quality of a non-aqueous drilling fluid. The fine solids often require the drilling fluid to be diluted with neat base oil as chemical treatments are not generally effective.

The drilled solids buildup is attributed to the increased drilling speed, but the disintegration of the solids is often ignored as non-aqueous drilling fluids are believed to be shale inhibitive regardless of the type of base oil used. It is known that excessive drilled solids can lead to an increase in drilling fluid viscosity. A common practice in laboratory testing is the use of Rev-Dust or other finely ground clays to simulate drilled solids. One key factor missed is the TOC or organic matter concentration in shale formations. The average organic matter measured as TOC can be over 8 wt% in US shale formations. It may be even higher in certain shale sections within the same wellbore. During drilling, the organic matter along with shale solids are integrated into the drilling fluid system and this organic matter can chemically interact with the base oil depending on the concentration of relatively polar components in the oil such as aromatics.

Round 1

Fluid Properties Impacted by Shale Samples A and B

As shown in Figure 1, shale sample A has a high content of framework silicate at 43 wt%. Framework silicate typically includes quartz and plagioclase feldspar. Sample A also has a high content of carbonates. These carbonates are usually comprised of calcite and dolomite. The TOC of 17.9 wt% although higher than most shales, allowed for the effect of organic matter on drilling fluid properties to be determined without being masked by interference from other components in the drilling fluid.

45 lbs/bbl (ppb) of fine solids were included in the drilling fluid formulations prepared for the fine solid contamination test in the first round.

The rheological properties are shown in Figure 2. The properties were obtained with an Ofite 900 viscometer at 150 °F. The dial readings are plotted as a function of the viscometer speed from 3 to 600 rpm. The solid lines represent the rheological properties before hot rolling. The dotted lines are the dial readings after hot rolling at 250 °F for 16 hours. The impact of the Shale A fine solids and dispersed organic matter is different in the OBM compared to the SBM. Before hot rolling, the OBM shows a higher rheological profile while the properties are similar after hot rolling.

The rheological properties can be further analyzed with the plastic viscosity (PV), yield point (YP) and low shear rate yield point (LSYP) data as shown in Table 3. The PV does not change much after hot rolling while the YP and LSYP decrease more significantly especially in OBM, which indicates a change in the chemical forces between the solid particles.

The HTHP filtration results before hot rolling are shown in Figure 3. Both OBM and SBM exhibited reasonable fluid loss while water was observed in the filtrate of OBM. In addition, the filtrate from OBM is much darker, which is an indication of solubilization or dispersion of organic matter from the shale particles. More interestingly, the OBM filter cake was observed to be stickier than that of the SBM, as is illustrated in Figure 4. A stainless steel bar was gently rolled over the filter cake and the amount of filter cake sticking to the bar was quantified. After rolling there was 5 times more OBM filter cake on the steel bar than with the SBM. Filter cake stickiness can be detrimental to drilling performance in the field including higher torque, slower casing running speed, and reduced cement integrity.

Shale sample B was acquired from between 7,000 and 8000 ft depth in a shale formation. It contains 8.7 wt% TOC or organic matter and 24.6 wt% clay content. The core sample was processed into fine solids of <100 microns size as shown in the particle distribution in Figure 1. The concentration of fine solids added was increased to 10 vol% or 91 ppb as shown in Table 4. The particle size distribution of the fine dry solids before being placed into the fluid provides a baseline for particle size change. Similar to the first round study with shale sample A, OBM and SBM fluids were mixed and hot rolled at 250 °F for 16 hours. The fluid properties were measured before and after hot rolling.

The rheological properties are shown in Figure 5 and in Table 5. In comparison to the results with shale sample A, the overall rheological properties are lower and the reduction is interpreted to be due to the lower TOC; however, the OBM showed a much higher viscosity than SBM before and after hot rolling. The difference in YP indicates a higher chemical force between the particles in OBM.

The rheological properties can be further explained with the particle size analysis as shown in Figure 6. The PSDs of the dry solids and of the fluids containing solids before and after hot rolling are compared. In the case of OBM, it shows a clear change in solids particle size distribution whereas the change is minimal in SBM.

HTHP filtration was also conducted with muds containing shale B fine solids. The filtrates were collected for chemical analysis to reveal the compositional change, which is believed to be related to the interaction between the base oil in the fluid and organic matter in the shale samples. Specifically, molecules that are smaller than C10 were quantified. The concentration of compounds with carbon chains C10 or less was determined to be 2 wt% in the diesel base oil and it decreased to 0.88 wt% in the filtrate from OBM. In contrast, the < C10 concentration in the synthetic base oil was only 0.5 wt% and it decreased to 0.37 wt% in the SBM filtrate. The majority of <C10 components in diesel are aromatics such as BTEX. It is interpreted that the < C10 components in OBM are more readily absorbed by organic matter in the shale samples, which can cause disaggregation and particle size changes.

Round 2

Accretion Test with Shale Sample A

To further understand the shale solid disintegration and interaction with the pipe surface, an accretion test was conducted with shale sample A. In the field, accretion is the gradual buildup of solids on the outside of the drill pipe or the inside of casing. 75 ppb of 5-10 mesh shale sample A was added to both OBM and SBM. The fluid formulations are the same as shown in Table 1 except the fine solids were replaced with 5-10 mesh solids. The fluids were hot rolled at 250 °F for 3 days and the results are shown in Figure 7. Noticeably, more fluid and solids adhered to the bar in the case of OBM. The amounts of solids were quantified by drying the wet steel bars. SBM showed an 83% reduction in solids on the steel bar surface compared to OBM.

The results with shale sample A demonstrate the impact of organic matter on the fluid properties and drilling performance as sample A contains only a small amount of clay, and the framework and carbonate minerals are considered inert solids.

Accretion Test with Shale Sample B

Accretion and recovery tests were conducted with 5-10 mesh solids from shale sample B. The fluid formulation for the shale sample B accretion and recovery tests was the same as shown in Table 4 except that the fine solids were replaced with 75 ppb of 5-10 mesh solids. The fluids along with the stainless-steel bar were hot rolled at 250 °F for 3 days. Figure 8 shows the steel bars recovered from OBM and SBM. The quantity of residue with the OBM is more than double that measured with the SBM, which is consistent with the results with shale sample A. Diesel results in a stickier fluid as its aromatic components interact with the organic matter from the shale.

Recovery Test with Shale Sample B

The most interesting result in this study is from the shale recovery test as shown in Figure 9 and Table 6. For comparison, a field WBM was included in the shale recovery B determination in the second round test. As expected, only 3.5 wt% of shale particles were recovered in the WBM since the clay minerals in the shale are sensitive to water penetration. In other words, 96.5 wt% of shale particles disintegrated or became finer solids when contacted with WBM, which is primarily the reason that non-aqueous fluids are predominantly chosen to drill horizontal shale wells. Interestingly, the shale particle recovery in OBM was only 26.1 wt% while 98.9 wt% recovery was achieved in the SBM. Due to the significant difference, the tests were repeated in the laboratory. In the rerun, 22.2 wt% shale was recovered in OBM and 97 wt% shale recovered in SBM.

The low percentage of shale recovery in OBM was somewhat surprising since clays are not expected to react with a non-aqueous fluid and similar results have not been reported previously. This provides a good explanation on the current industrial challenge – as lateral sections of horizontal wells are drilled to greater lengths with higher penetration rates, the increasing drilled solids content in OBM can detrimentally affect fluid properties and result in reduced drilling performance. During drilling, the cuttings are primarily removed by shale shakers as illustrated in Figure 9, with shaker performance being affected by the size of solids. If the cuttings disintegrate rapidly during circulation, the solids removal efficiency is largely limited. Although there are other devices such as centrifuges to remove finer solids, the capacities are not matching the pumping rate and they also result in extra costs. The cuttings remaining in the fluid system further degrade during drilling, which results in yet more fine solids being generated. It helps to explain the fact that more than 50% of the solids in some field OBMs are less than 6 microns.

On the other hand, the shale recovery was close to 100% in the synthetic fluid due to the non-polarity and ultra-low aromatic content. When translated into field performance, the SBM will yield a higher solids removal efficiency, which in turn reduces the fine solids content in the fluid and reduces equipment and chemical treatment cost.

Certainly, the overall drilling performance is determined by the minerology and TOC content of the formation, but the study provides a method to quantitatively understand the transformation of shale cuttings in non-aqueous drilling fluids. Currently, most of the shale disintegration tests are run in aqueous based fluids. It is recommended to adapt the procedure described in this paper to evaluate the performance of non-aqueous drilling fluids especially for shale drilling.

Conclusions

The two shale samples selected have shown an interesting interaction in diesel oil based vs. synthetic based drilling fluid. The TOC or organic matter plays a role in shale disintegration and fines generation. It affects the drilling fluid properties and it explains the reason that viscosity control is a primary industrial challenge. The results help understand the cause of the buildup of fine solids (less than 6 microns) in diesel oil based drilling fluid. On the other hand, the effects of the two shale samples are minimal in the synthetic based fluid, which is attributed to the non-polarity and ultra-low aromatic content.

The laboratory findings are in line with field drilling performance including rate of penetration, casing running speed and cement job quality and can be used to understand the drilling challenges for operators.

It is recommended to run shale fines contamination, accretion and recovery tests before drilling through a shale formation with moderate to high TOC content. The combined impact of organic matter and clay in shale on drilling fluids needs to be considered to achieve better drilling performance especially for long horizontal wells.

Acknowledgments

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Nomenclature

LGS = Low Gravity Solids
TOC = Total Organic Carbon
SBM = Synthetic Based Mud
OBM = Diesel Oil Based Mud
WBM = Water Based Mud
PV = Plastic Viscosity
PSD = Particle Size Distribution
NADF =Non-Aqueous Drilling Fluid
OWR = Oil Water Ratio
BTEX = Benzene, Toluene, Ethylbenzene, Xylene
YP = Yield Point (lb/100ft²)
LSYP =Low Shear Yield Point (lb/100ft²)
HTHP = High Temperature High Pressure
cP =Centipoise
BHR = Before Hot Rolling
AHR = After Hot Rolling
Fwk = Framework

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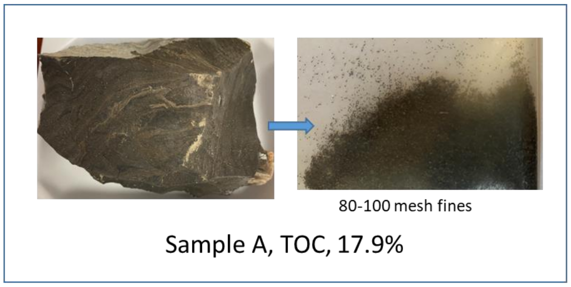

	Organic	Mineral Groups				
	TOC	Fwk	Clay *	Carb	Other	Total
	wt%	wt%	wt%	wt%	wt%	wt%
Sample A	17.9	43	5.8	39.2	12	100
Sample B	8.7	36.5	24.6	32.9	6	100

* Illite + Mica are the only clays in sample A and B

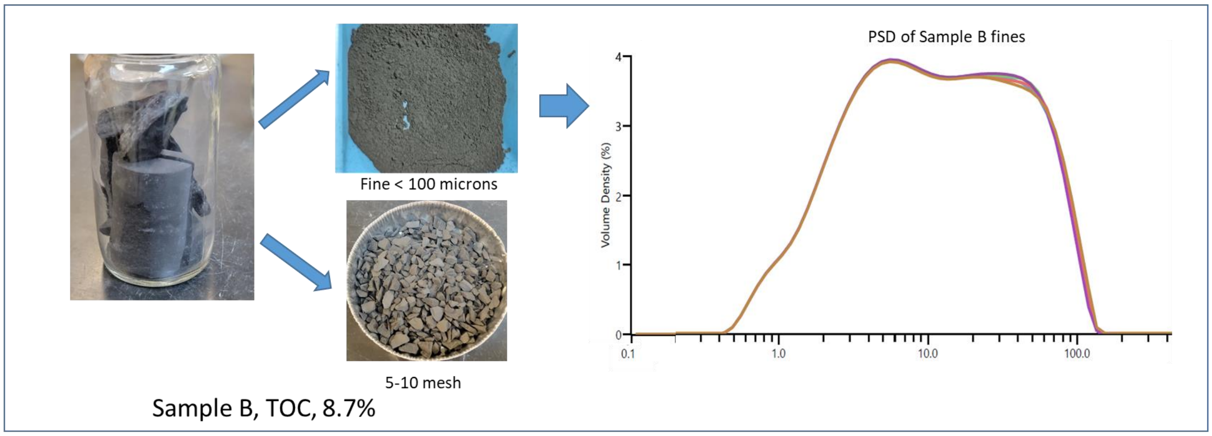

Figure 1 – Shale Samples A and B

Test Round	Shale Sample A (17.9 wt% TOC, 5.8 wt% Clay)	Shale Sample B (8.7 wt% TOC, 24.6 wt% Clay)
1A. Effect of Fine Solids Contamination on Rheology	Yes	Yes
Size of fines	80-100 mesh	<100 microns
Fines concentration	45 lbs/bbl	91.1 lbs/bbl
Aging conditions	Rolled 16 hrs at 250 °F	Rolled 16 hrs at 250 °F
1B. Particle Size Reduction	No	Yes
Size of fines	----	<100 microns
Fines concentration	----	91.1 lbs/bbl
Aging conditions	----	Rolled 16 hrs at 250 °F
2A. Accretion	Yes	Yes
Simulated cuttings size	5-10 mesh	5-10 mesh
Simulated cuttings concentration	75 lb/bbl	75 lb/bbl
Aging conditions	Rolled 72 hrs at 250 °F	Rolled 72 hrs at 250 °F
2B. Shale Recovery	No	Yes
Simulated cuttings size	---	5-10 mesh
Simulated cuttings concentration	---	75 lb/bbl
Aging conditions	---	Rolled 72 hrs at 250 °F
Determine retained on mesh size	---	Larger than 10 mesh

Table 1 – Test matrix for organic matter interaction study

Product	lb/bbl
25% CaCl2 Brine	128.04
Emulsifier	10
Lime	3
Diesel	179.18
Organoclay	6
Fine Solids	45

OBM

Product	lb/bbl
25% CaCl2 Brine	128.04
Emulsifier	10
Lime	3
Synthetic base oil	168.52
Organoclay	6
Fine Solids	45

SBM

Table 2 – Drilling fluid formulation for determining the effect of shale sample A fine solids (80-100 mesh) on rheology of SBM and OBM

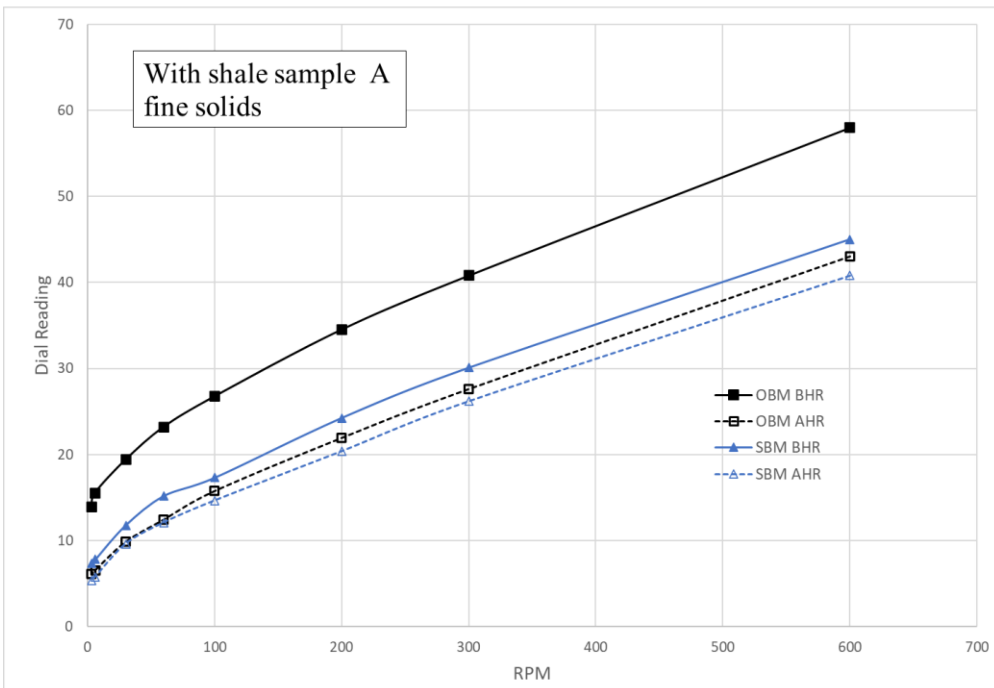

Figure 2 – Rheological properties of OBM and SBM containing 45 ppb finely ground shale sample A

	OBM, BHR	OBM, AHR	SBM, BHR	SBM, AHR
PV, (cP)	17.2	15.4	14.9	14.6
YP, (lb/100 ft2)	23.6	12.2	15.2	11.6
LSYP, (lb/100ft2)	12.3	5.7	6.9	5.0

Table 3 – PV, YP and LSYP of OBM and SBM containing shale sample A

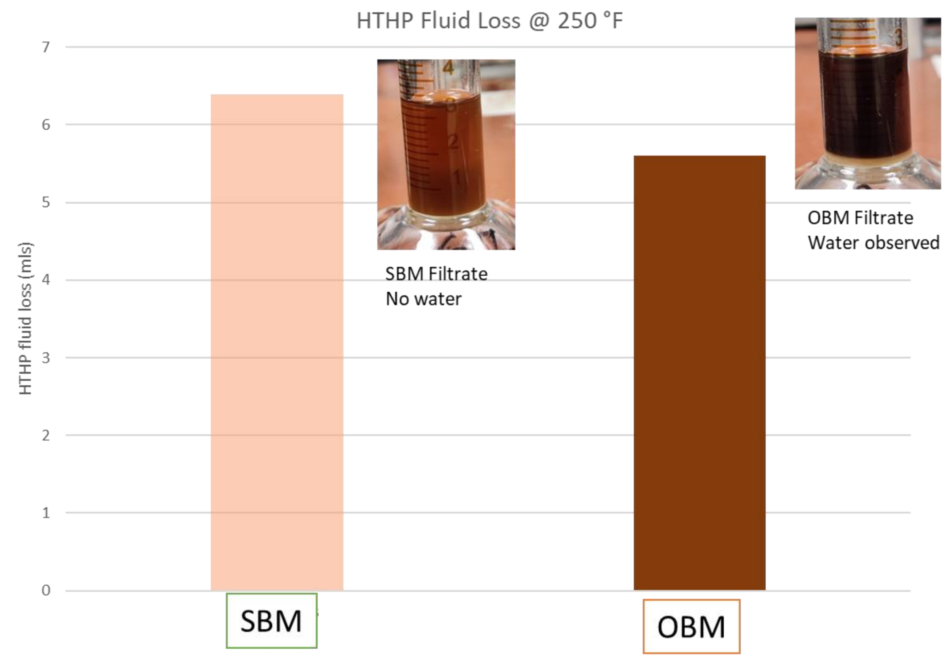

Figure 3 – HTHP filtration results before hot rolling of SBM and OBM after contamination with shale sample A fines

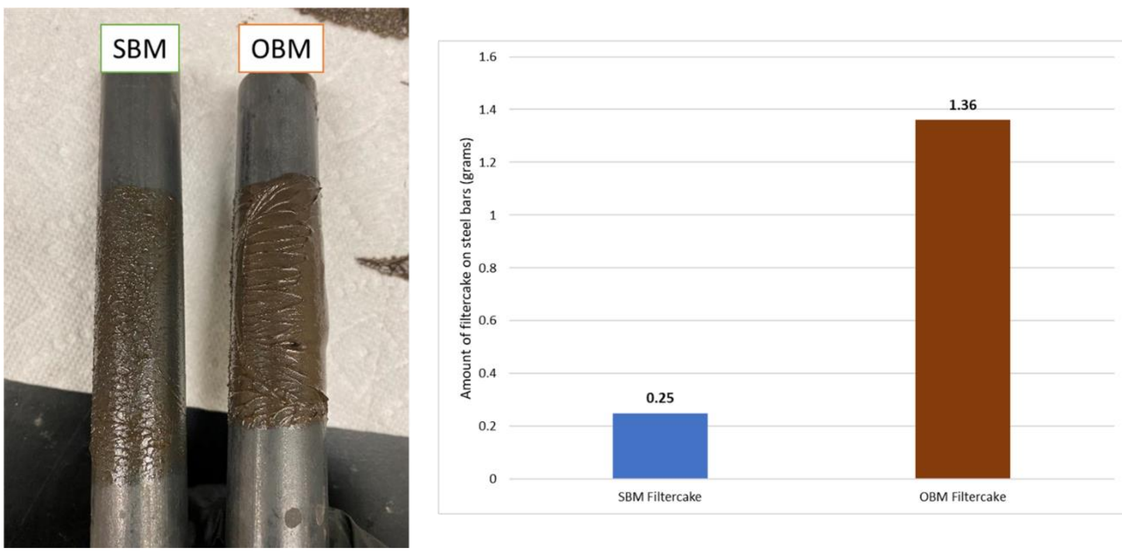

Figure 4 – Adherence of SBM and OBM filter cake to metal surface before hot rolling after contamination of drilling fluids with shale sample A fines

Product	lb/bbl
25% CaCl2 Brine	101.60
Emulsifier	10.00
Lime	3.00
Diesel	183.00
Organoclay	5.00
Fine solids	91.13
Totals	393.74

OBM

Product	lb/bbl
25% CaCl2 Brine	101.60
Emulsifier	10.00
Lime	3.00
Synthetic base oil	172.11
Organoclay	5.00
Fine solids	91.13
Totals	382.84

SBM

Table 4 – Fluid formulations with fine shale sample B

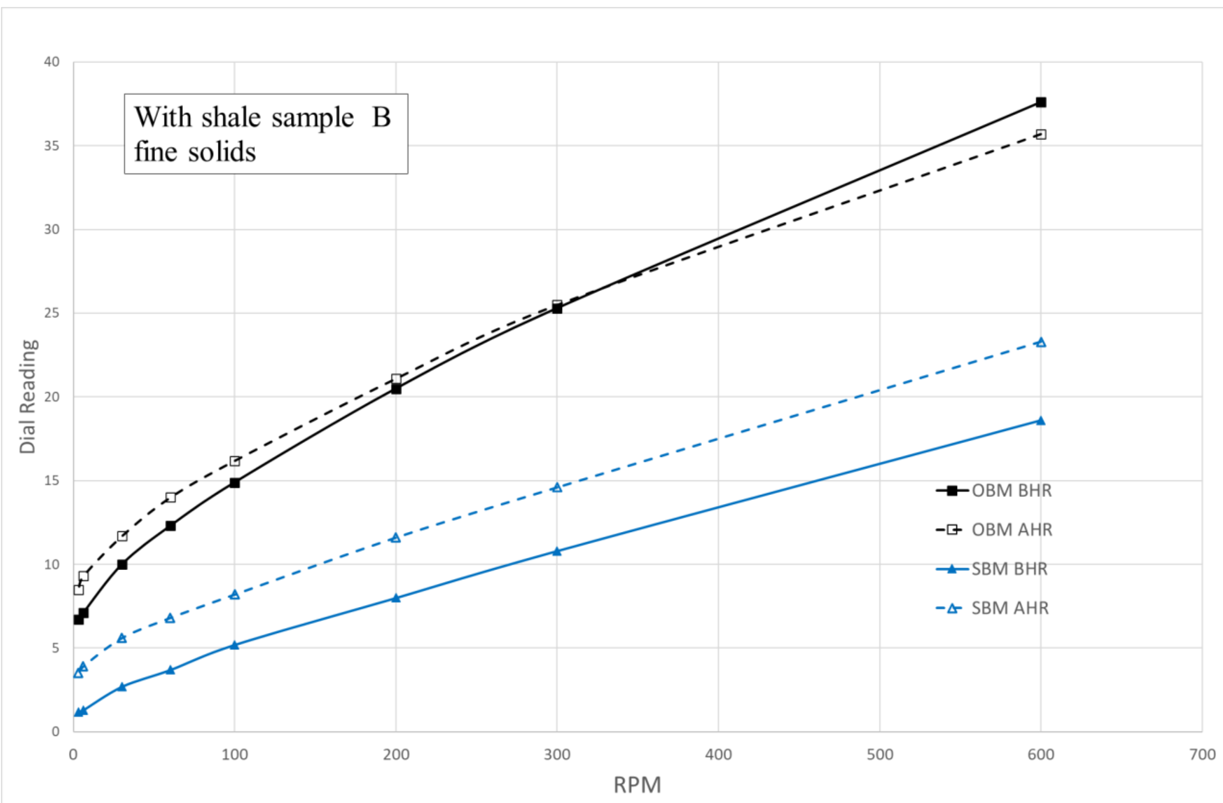

Figure 5 – Rheological properties of OBM and SBM containing 91 ppb finely ground shale sample B

	OBM, BHR	OBM, AHR	SBM, BHR	SBM, AHR
PV, (cP)	12	10	8	9
YP, (lb/100 ft2)	13	15	3	6
LSYP, (lb/100 ft2)	6.3	7.7	1.1	3.1

Table 5 – PV, YP and LSYP with shale sample B

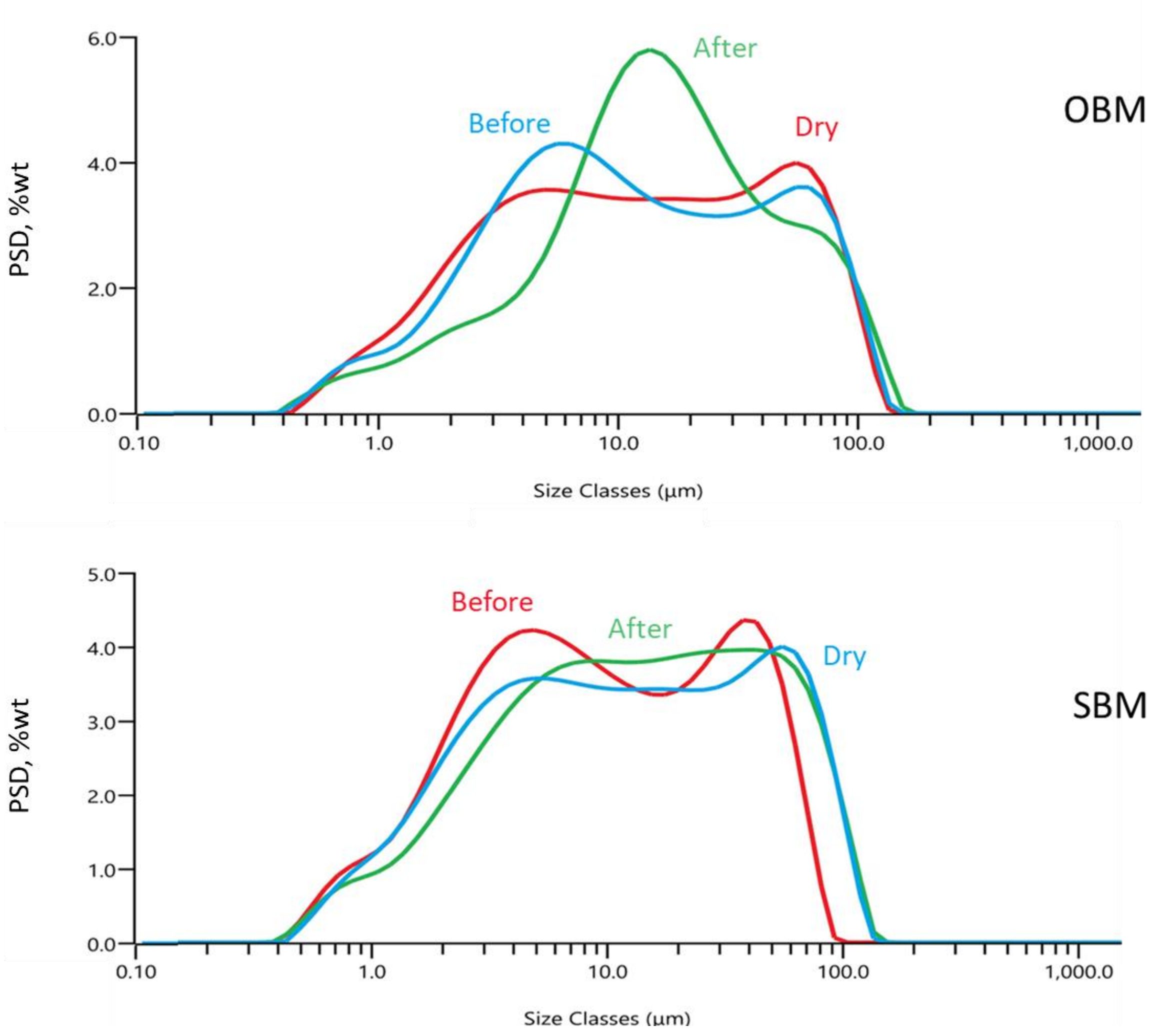

Figure 6 – Particle size distribution change before and after hot rolling drilling fluids with shale sample B fines

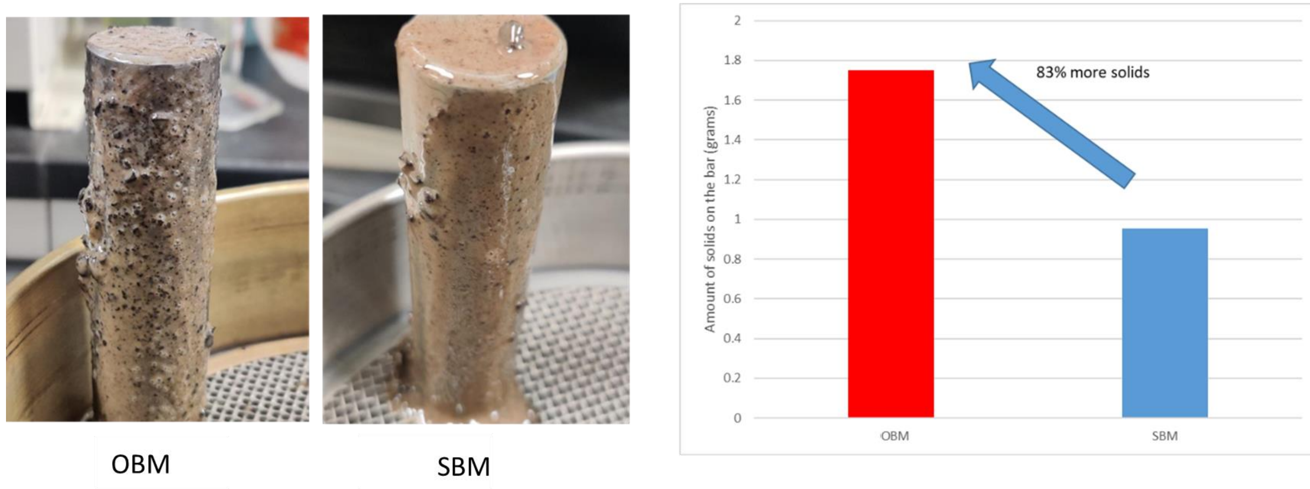

Figure 7 – Accretion results with shale sample A

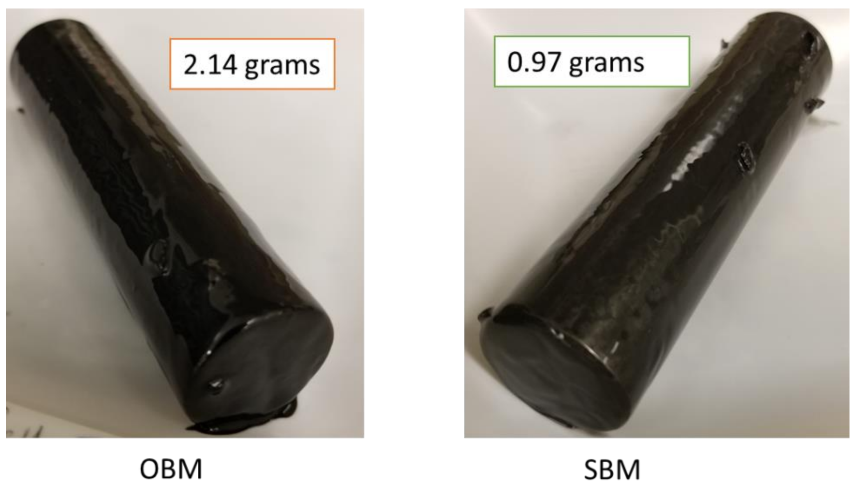

Figure 8 - Accretion results with shale sample B

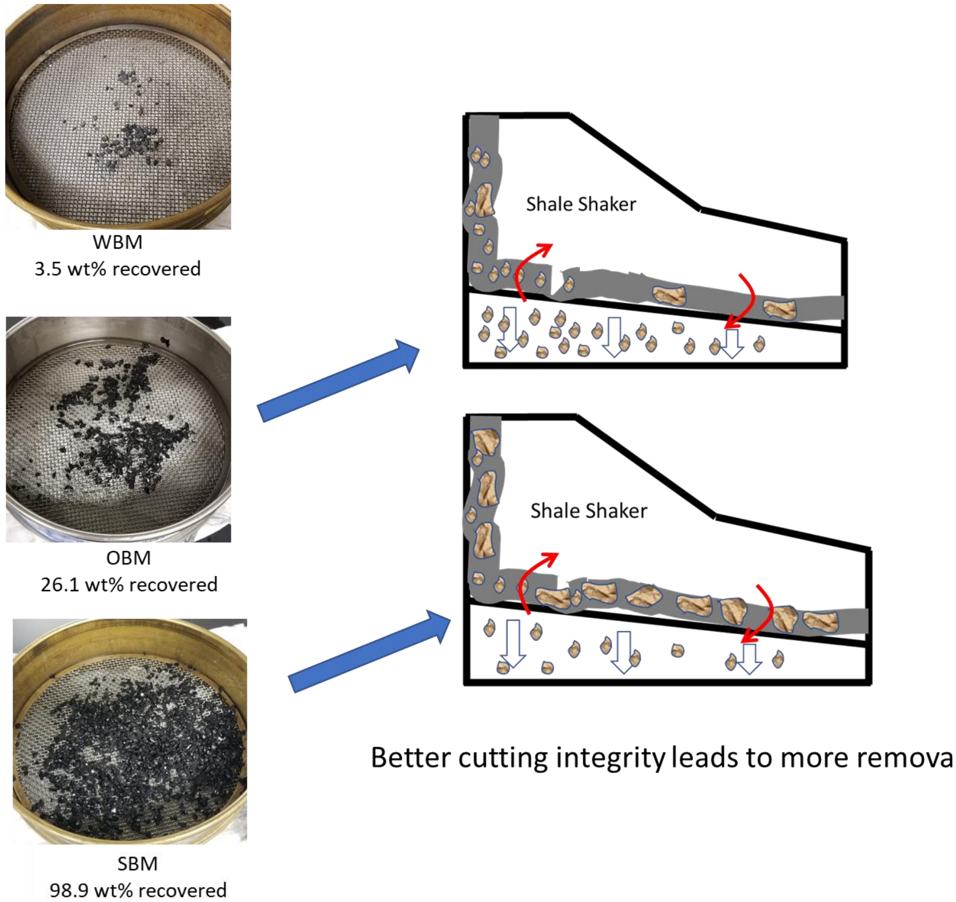

Figure 9 – Shale sample B recovery test results

SBM	98.0% *
OBM	24.2% *
WBM	3.5%
TOC	8.7%
Clay	24.6%

* Average of two tests

Table 6 – Shale recovery in connection to the TOC and clay content of shale sample B