AADE-07-NTCE-03

Novel Sag Reducing Additive for Non-aqueous Drilling Fluids

Olusegun M. Falana, Bharat B. Patel, and Wayne S. Stewart, Drilling Specialties, Division of Chevron Phillips Chemical

Abstract

Increasingly, sag remains an inveterate problem in the drilling industry. Sag is considered as the settling and/or stratifying of heavy inert materials in drilling fluid as it is being pumped through the wellbore. Thus, the specific gravity of the drilling fluid along the fluid column varies. This may lead to problems such as lost circulation, well-control difficulties, poor cement jobs and stuck pipe in drilling operations. Sag problem is particularly severe with directional wells or high pressure and high temperature deepwater wells. Hitherto, there is no “magic bullet” to mitigate or manage sag.

Sag is affected by several parameters. Yet, the interdependence of the parameters is unknown and complicated. As such, one of the challenges facing the understanding and management of sag is a lack of industrial or API standard for measurement and/or identifying key sag causative or predictive parameters. In this paper, we discuss a method to measure sag and the use of our proprietary novel sag reducing additive (NSRA).

To quantify sag, we measure changes in specific gravity of base mud and the base mud treated with our novel additive. We measure the initial specific gravity (SG_i) and final specific gravity (SG_f) after rolling at high temperatures. Then, we calculate Sag (ppg) using the following equation:

$$\text{Sag (ppg)} = (SG_f - SG_i)\ (8.33).$$

Thus, treatment of invert-emulsion drilling fluids with the NSRA reduced sag considerably. Though significant in every case, reduction in sag depends on base mud and test procedure employed. Traditionally, materials such as organophilic clays have been added to drilling fluids to overcome sag. However, those materials undesirably increase the viscosity of the drilling fluid and thus cause inefficient drilling. Impressively, the novel sag reducing additive offered improved rheological properties, lower fluid loss and no adverse impact on electrical stability.

Introduction

Hitherto, sag, commonly referred to as barite sag, remains a recurring problem in the drilling industry.[1] Sag is defined as the settling and/or stratifying of heavy inert materials, such as barite, in drilling fluid as it is being pumped through the wellbore. Consequently, the specific gravity or weight of the drilling fluid along the fluid column varies. Early investigators considered sag as a complex phenomenon involving static or dynamic settling of weight materials.[2-4] However, managing dynamic sag is more important than managing static sag of weighted materials in drilling fluids.[3, 4]

The sag phenomenon is associated with a number of field operation conditions. First, in several mature fields around the globe, drilling new wells demands use of weighted muds to counter pore, collapse and fracture pressures. Therefore, muds with specific gravity (SG) of about 1.4 or higher is frequently used. Unfortunately, there is increased sag potential when SG of drilling fluids is about 1.4 to 2.4 (~12 ppg – 20 ppg). Second, sag is potentially severe when drilling at angles $\geq 30^o$ with weighted mud.[5, 6] Third, the employment of invert-emulsion fluids for the advantages that they offer such as high rate of penetration, increase lubricity in directional and horizontal wells including wellbore stability.[6] To keep well under control while drilling, weighted material must be suspended and this is especially difficult with synthetic or oil based muds (S/OBM). Fourth, sag occurs when drilling in hostile or deepwater environments of high pressure and temperature (HPHT) with S/OBM.

In light of the recurrence of sag, the consequences are well documented.[6] For instance, sag leads to insufficient drilling fluids for well control, wellbore instability and stuck pipe, fracturing of formation while re-suspending a weight material bed as well as insufficient displacement efficiency during cementing operations. Apparently, when there is sag, cost of operation can easily escalate to several millions of dollars above budget.

Sadly, not only is there a lack of industrial or API standard to measure and/or identify key sag causative parameters, but also, there is no “magic bullet” to alleviate or manage sag.[1] Most of the test methods known are laboratory dependent and might often fail. The viscometer sag test (VST), sag-flow loops and static aging of mud in special cell tubes, pressure bombs and dynamic high angle settling tool (DHAST™) are known examples.

Notwithstanding the paucity of standard test method, a number of means of managing sag have been advanced either on the basis of theory or field experience. To-date, the best way to manage sag is through the observance (which is challenging to most drilling engineers) of sound engineering strategies and guidelines.[1] Saasen[7] submitted that sag can be reduced in simple emulsions by “increasing the viscosity of the continuous phase or moving the critical shear rate where shear thickening occurs to lower values". Further, that a) a successful increase in the viscosity of the continuous phase of an emulsion will reduce both static and dynamic sag; and b) reduction of the critical shear rate for onset of shear thickening will reduce the degree of static sag. Among others, he recognized the use of proper organophilic clay and low-end rheology modifiers, which are mainly surfactants and might pose environmental concerns. Conventionally, materials such as organophilic clays have been added to drilling fluids to overcome sag problem. However, those materials undesirably increase the plastic viscosity (PV) of the drilling fluid and thus cause the drilling efficiency to decrease. As a result of the increase in PV, relatively high pump pressures may be required to convey the fluid into and out of the wellbore. Further, it may be difficult to remove drill cuttings from the wellbore, resulting in the fluid having an excessive equivalent circulation density (ECD) and thus leading to the loss of its circulation in the wellbore. A need therefore exists to develop a method of reducing sag in a non-aqueous fluid such as a drilling fluid without significantly increasing the viscosity of the fluid.

The Technology

The novel sag-reducing additive (NSRA) is developed to alleviate sag in invert emulsion drilling fluids (IEDF) without increasing low-end rheological properties. Sag is affected by several parameters. Yet, the interdependence of the parameters is unknown and complicated. However, changes in the rheological properties of IEDF are evident when there is sag. To quantify sag, we measure changes in specific gravity of base mud and the base mud treated with our NSRA. We measure the initial specific gravity (SG_i) and final specific gravity (SG_f) after rolling at high temperatures. Then, we calculate Sag (ppg) using the following equation:

$$\text{Sag (ppg)} = (SG_f - SG_i)\ (8.33). \qquad \text{(i)}$$

Results and Discussion

In the following examples, the flow properties (PV, YP, and Gels) of the drilling fluid samples were tested using a Viscosity-Gel (VG) meter (Model 35) in accordance with the API 13B-2.

Example 1: Mineral Oil-Based Drilling Fluid

a) An invert emulsion drilling fluid (IEDF) containing the following materials was prepared: 1,980 grams of commercially available mineral oil, 70 grams of lime, 35 grams of organophilic clay, 70 grams of primary emulsifier, 11.67 grams of secondary emulsifier, 760 grams of $CaCl_2$ brine having a density of 10 lbs/gal; and 175 grams of rev dust for simulating drill cuttings, the rev dust being an altered Ca-montmorillonite, Al-silicate with low quartz content and low alkaline earth metal content. After transferring the mineral oil into a bucket and then stirring the oil sample with a dispersator, the materials were added about five minutes apart into the oil sample according to the order they are listed. The IEDF was mixed for 20 minutes at a very high shear using a ROSS mixer (Model ME-100L). The IEDF was then divided into 2 samples containing 208 grams each of the IEDF, and the samples were placed in 2 separate jars. Next, each sample was then reformulated while stirring with a Multimixer and adding the corresponding materials shown in Table 1. After the addition of each material, the sample was stirred for 10 minutes. The specific gravity (SG_i) was measured and then each sample was transferred into an aging cell (316SS). The cells were capped, rolled in an oven at 160 ^oF for about 3.5 hours, and cooled. After stirring samples (about two minutes), the cells were capped and further rolled in the oven at 176 °F for 16 hours. The hot cells were kept in upright position for 2 hr in an oven at 176 ^oF. Upon quickly cooling the cells under copious cold running tap water, the cells were opened and a portion (approximately 225 mL) of the fluid sample from the top of each of the aging cells was gently poured back into the original jar. The remaining portion of the fluid sample in the aging cells was mixed well with a spatula and exactly 42.1 mL of this fluid sample of each aging cell was transferred into a pre-calibrated beaker and weighed (W, grams). Each sample was stirred 10 minutes with the Multimixer and various flow properties (PV, YP, and Gels) of each sample were then measured (Table 1, Rheological Properties after 176 ^oF). The specific gravity (SG_f) and Sag [ppg, equation (i)] were calculated in accordance with the following equation:

$$\text{Specific Gravity } (SG_f) = (\text{W, grams}) \div (42.1\text{, grams}) \qquad \text{(ii)}$$

If no sag problem occurred, the specific gravity (SG_f) of the 2 samples should be 1.52 (the same as SG_i). That is, the specific gravity at the top and the bottom of the fluid is the same. However, the SG_f of Sample 1 (control) was 2.62 (Table 1, Sag after 176 ^oF). Therefore, the SG_f of the control sample is much higher than 1.52, resulting in 9.16 ppg sag. Whereas, under the same conditions, Sample 2 exhibited only 0.58 ppg sag. Thus, the sag problem was practically solved in Sample 2 by employing NSRA. Still, the flow properties of the 2 samples are about the same.

b) After the tests reported in a) above, samples were mixed on the Multimixer and then rolled for about 2.5 hr in an oven at 225 ^oF in the same aging cells. The hot samples were kept in upright position for 2.5 hr at 225 ^oF in the oven and cooled to about 80 ^oF. Then, SG_f and rheological properties were measured as described above (Table 1, see Sag and Rheological Properties after 225 ^oF). Sag was 8.75 ppg and 1.25 ppg in Sample 1 and Sample 2 respectively. Albeit, at this elevated temperature, sag is low in Sample 2, which contains the NSRA.

c) Furthermore, the 2 samples were tested using a modified published method for "dynamic" sag.[4] Thus, Sample 1 and Sample 2 were mixed separately on the Multimixer for 10 minutes. Immediately, 175 mL of the sample was transferred into a heating cup. While stirring at 600 RPM on the VG meter, the sample was heated. When the temperature reached 150 ^{o}F, the speed was switched to 100 RPM and a timer was turned on. After stirring for 30 minutes at 100 rpm (and maintaining at about 150 °F), the VG meter was turned off, and immediately but carefully, a portion of the hot fluid sample (approximately 150 mL) from the heating cup was gently poured back into the original jar. The remaining portion of the fluid sample in the heating cup was mixed well with a spatula and exactly 12.35 mL of this fluid sample was transferred into a pre-calibrated beaker and weighed. Here, the specific gravity (SG_f) was calculated in accordance with the following equation [including equation (ii)]:

Specific Gravity (SG_f) = Weight / 12.35 (iii)

Hence, Sag (ppg) by this method was 2.99 ppg in Sample 2 and 4.956 ppg in Sample 1 (Table 1, "Dynamic" Sag after 150 ^{o}F). Though not to the same degree as shown in a) and b), the ability of NSRA to reduce sag is yet again demonstrated with this significant reduction (~2 ppg) in sag relative to the base mud.

Example 2: Diesel-Based Drilling Fluid

The novel sag reducing additive was tested in an OBM formulated with diesel oil. The OBM was obtained from a plant in the Houston area. After mixing the OBM with a Ross mixer for 45 minutes, the mud density was determined (10.13 ppg). Further, using the same preparatory method described *vide supra*, two samples with the composition given in Table 2 were formulated. These samples were rolled in the aging cells in oven at 250 ^{o}F for 16 hours. The hot cells were kept in upright position and undisturbed for about 2 hours at room temperature. The cells were quickly cooled and opened. Sag values were then obtained in the same manner described above in Example 1, a). These test results are provided in Table 2 (Sag after 250 ^{o}F). In this case, the specific gravity of the samples (without any sag/settling) was measured to be 1.216. Then, "dynamic" sag was measured on the 2 mud samples following the same method described in Example 1, c). The values obtained are tabularized in Table 2 ("Dynamic Sag after 150 ^{o}F).

In the 2 samples, there is relatively little sag (0.35 and 0.79 ppg). However, on the basis of the results at 6 rpm and 3 rpm (Table 2, Rheological Properties at 100, 120 and 150 ^{o}F), the sample treated with NSRA (Sample 4) gave better low-shear rheological properties and hence the more suspending characteristics. Impressively, NSRA is effective in reducing fluid loss. Essentially, NSRA offered double whelming advantages of controlling sag and reducing fluid loss. As such, the use of NSRA can save the cost of using organophilic clay for fluid loss control, especially in regions with the most stringent environmental regulations. Still, under the alternative "dynamic" test conditions, NSRA reduced sag to 0.491 ppg (Sample 4) from 0.816 ppg.

Example 3: Synthetic-Based Drilling Fluid

The compatibility and effectiveness of the NSRA was also considered in a synthetic-based mud (SBM) formulated with an olefin. A non-weighted SBM (NSBM), containing C_{16-18} olefin (264 g), lime (8.08 g), organophilic clay (4.04), emulsifier (12.93), wetting agent (4.04), brine (101.4 g), and rev dust (24.24 g), was prepared by mixing the materials with Multimixer. The NSBM was mixed for 5 minutes at a very high shear using ROSS mixer. The NSBM was then divided into 2 samples containing 200 grams each, and the samples were placed in 2 separate jars. Next, each sample was then reformulated while stirring with the Multimixer and adding the corresponding materials shown in Table 3. After the addition of each material, the sample was stirred for 10 minutes. The specific gravity (SG_i) was measured. Each sample was then transferred into the aging cell and then tested for sag in accordance with the method described above, Example 1, a). The sag was measured after rolling for 4 hours in an oven at 176 ^{o}F and again after rolling 16 hours at 250 ^{o}F (see Table 3, Sag after 176, and 250 ^{o}F). The rheological properties after hot rolling at 250 ^{o}F were also determined at different temperatures, viz, 80 ^{o}F, 120 ^{o}F and 150 ^{o}F. The results are summarized in Table 3 (Rheological Properties after 250 ^{o}F). At 176 ^{o}F, the same sag value of 2.5 ppg was recorded for both samples. Unlike in mineral oil (Example 1), a higher temperature might be required to activate NSRA in the SBM. Thus, at 250 ^{o}F, NSRA reduced sag to 1.50 ppg from 5.0 ppg in the base mud. In addition, similar flow properties are obtained in the control (Sample 5) and the NSRA treated (Sample 6) samples. The fluid loss at high pressure and temperature (HPHTFL) is lower in Sample 6 than in Sample 5, which is the control; corroborating the ability of NSRA to reduce fluid loss in addition to controlling sag.

Overall, in all the examples herein discussed, the flow properties of the IEDF samples (control and NSRA treated) were about the same. But, a reduction in sag is expected to result from an increase in flow properties such as apparent viscosity, plastic viscosity, yield point, and gel strength. However, the use of the NSRA advantageously did not adversely affect the flow properties of the IEDF.

Conclusions

In conclusion, treatment of invert emulsion drilling fluids (weighted oil-based or synthetic-based) with the novel additive, reduced barite sag considerably. Though significant in every case, reduction in sag depends on base mud and test procedure employed. Additionally, the novel sag reducing additive:

- Improves suspension properties of drilling fluids and produces no adverse impact on electrical stability
- Mixes readily, and is compatible with all commonly used materials in oil-based and synthetic-based drilling fluids
- Is temperature stable ($\geq$ 350 ^{o}F)
- Reduces HPHT fluid loss and
- Is a free flowing white powder expected to be environmentally benign.

Acknowledgments

The authors are grateful to the management of Chevron Phillips Chemical Company, LLC for supporting this work and the permission to publish this article.

Nomenclature

AEC = *API Evaluation Clay*
API = *American Petroleum Institute*
DHAST = *Dynamic High Angle Settling Tool*
ECD = *Equivalent Circulation Density*
ES = *Emulsion Stability*
Gels = *Gel Strength, lb.100ft^{-2}*
HPHT = *High Pressure High Temperature*
HPHTFL = *HPHT Fluid Loss, mL*
IEDF = *Invert Emulsion Drilling Fluids*
NSRA = *Novel Sag Reducing Additive*
PV = *Plastic Viscosity, cP (centipoises)*
RPM = *Rotations per Minute*
SG = *Specific Gravity*
SG_i = *Initial Specific Gravity*
SG_f = *Final Specific Gravity*
S/OBM = *Synthetic/Oil Based Mud*
VG = *Viscosity-Gel meter*
VST = *Viscometer Sag Test*
YP = *Yield point, lb.100ft^{-2}*

References

1. Scott, P.D., Zamora, M., and Aldea, C.: "Barite-Sage Management: Challenges, Strategies, Opportunities", IADC/SPE 87136, IADC/SPE Drilling Conference, Dallas, March 2-4, 2004.
2. Jamison, D.E. and Clements, W.R.: "A New Test Method To Characterize Settling/Sag Tendencies of Drilling Fluids In Extended Reach Drilling", ASME 1990 Drilling Tech. Symp., PD Vol. 27, 109-113.
3. Hanson, P.M., Trigg, T.K., Rachal, G. and Zamora, M.: "Investigation of Barite 'Sag' in Weighted Drilling Fluids in Highly deviated Wells", SPE 20423, SPE Annual Technical Conference, New Orleans, September 23-26, 1990.
4. Jefferson, D.T.: "New Procedure Helps Monitor Sag in the Field", ASME-91-PET-3, Energy Sources Technology Conference and Exhibition, New Orleans, January 20-24, 1991
5. Burrows, K., Carbajal, D., Kirsner, J. and Owen, B.: "Benchmark Performance: Zero Barite Sag and Significantly Reduced Downhole Losses with the Industry's First Clay-Free Synthetic-Based Fluid", IADC/SPE 87138, IADC/SPE Drilling Conference, Dallas, March 2-4, 2004.
6. Golis, G. and Grioni, S.: "Varied Application of Invert Emulsion Muds", JPT (March 1969), 261-266.
7. Saasen, A.: "Sag of Weighted Material in Oil Based Drilling Fluids", IADC/SPE 77190, IADC/SPE Asia Pacific Drilling Technology, Jakarta, Indonesia, September 9-11, 2002.

Table 1: Sag and Rheology Test Data of 12.7 ppg Mineral Oil-Based Mud Samples

Description	**Sample 1 (Control)**			**Sample 2 (NSRA treated)**		
Base Mud (g)	208			208		
Barite (g)	212			212		
NSRA[T] (ppb)	----			2.0		
Sag after 176 °F						
SG_i	1.52			1.52		
SG_f	2.62			1.59		
Sag (ppg)	**9.16**			**0.58**		
Rheological Properties after 176 °F						
Test Temp.	80°F	120°F	150°F	80°F	120°F	150°F
PV (cP)	20	16	14	21	16	14
YP (lb/100 ft^2)	1	1	0	5	4	4
6 RPM	2.2	2.5	2.5	3.2	3.7	4.3
3 RPM	2	3	2	3	3.7	4.3
Gels (10'/10", lb/100 ft^2)	7/18	8/16	9/13	8/24	10/23	10/17
Electrical Stability (Volt)	**---**	**463**	**---**	**---**	**696**	**---**
Sag after 225 °F						
SG_i	1.52			1.52		
SG_f	2.57			1.67		
Sag (ppg)	**8.75**			**1.25**		
Rheological Properties after 225 °F						
Test Temp.	80°F	120°F	150°F	80°F	120°F	150°F
PV (cP)	21	16	14	21	16	13
YP (lb/100 ft^2)	**1**	**1**	**0**	**4**	**4**	**5**
6 RPM	1.5	1.5	1	4	4.5	5.2
3 RPM	1.5	1.5	1	3.5	4.2	5
Gels (10'/10", lb/100 ft^2)	6/14	6/15	6/11	10/21	10/18	11/14
Electrical Stability (Volt)	**---**	**484**	**---**	**---**	**672**	**---**
"Dynamic" Sag at 150 °F[τ]						
SG_i	1.52			1.52		
SG_f	2.115			1.879		
"Dynamic Sag" (ppg)	**4.956**			**2.990**		

[T] Novel Sag Reducing Additive (NSRA). [τ] Modified from published "dynamic" sag test method.[4]

Table 2: Sag and Rheology Test Data of 10.13 ppg Diesel Oil-Based Plant Mud Samples

Description	Sample 3 (Control)	Sample 4 (NSRA Treated)
IEDF$^{\gamma}$	280 mL	280 mL
AEC^{T} (Drill Solids)	8 g (10 ppb)	8 g (10 ppb)
NSRA$^{\tau}$	--	**2.4 g (3 ppb)**
Sag (ppg) after 250 ^{o}F		
SG_i	1.216	1.216
SG_f	1.311	1.258
Sag (ppg)	**0.791**	**0.350**
Rheological Properties at 100 °F		
PV (cP)	18.5	20.5
YP (lb/100 ft^2)	0.5	2
6 RPM	2.3	4.2
3 RPM	2	4
Gels (10'/10", lb/100 ft^2)	5/6	8/15
Rheological Properties at 120 °F		
PV, (cP)	15.5	17
YP (lb/100 ft^2)	0	3
6 RPM	2	4.2
3 RPM	1.7	4
Gels (10'/10", lb/100 ft^2)	3.5/5	8/13.5
Electrical Stability (Volt)	598	1029
HPHTFL (mL) at 300 ^{o}F	**7.6**	**5.8**
Filter Cake	**2/32"**	**1/32**
Rheological Properties at 150 °F		
6 RPM	1.5	4
3 RPM	1.3	3.7
PV, (cP)	12.5	13.5
YP (lb/100 ft^2)	0	4
Gels (10'/10", lb/100 ft^2)	3.5/5	7.5/12
"Dynamic" Sag at 150 ^{o}F		
SG_i	1.216	1.216
SG_f	1.314	1.275
Sag (ppg)	**0.816**	**0.491**

$^{\gamma}$ Invert Emulsion Drilling Fluid (IEDF). ^{T} API Evaluation Clay. $^{\tau}$ Novel Sag Reducing Additive (NSRA).

Table 3: Sag and Rheology Test Data of 13.33 ppg Synthetic Oil-Based Mud Samples

Description	**Sample 5 (Control)**			**Sample 6 (NSRA Treated)**		
Base Mud (g)	200			200		
Barite (g)	246			246		
NSRA (ppb)	**----**			**2.5**		
Sag after 176 °F						
SG_i	1.60			1.60		
SG_f	1.64			1.64		
Sag (ppg)	0.33			0.33		
Sag after 250 °F						
SG_i	1.60			1.60		
SG_f	2.20			1.78		
Sag (ppg)	**5.00**			**1.50**		
Rheological Properties after 250 °F						
Test Temperature	80°F	120°F	150°F	80°F	120°F	150°F
PV, (cP)	29	21.5	17	30	22	18
YP (lb/100 ft^2)	3	1	1	5	2	1
6 rpm	4.2	3	2.2	5	3.5	3
3 rpm	3.7	2.5	2	4.2	3	2.5
Gels (10'/10", lb/100 ft^2)	5/7.5	4/5	3/4	6/8	5/6	3.5/5
Electrical Stability (Volt)	---	689	---	---	616	---
HPHTFL (mL) @ 250 °F	**15.0**			**9.8**		
Filter Cake	**6/32"**			**2/32"**		