AADE-24-FTCE-056

New Shale Inhibitor Tracking Technology for High-Performance Water-Based Drilling Fluids

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Abstract

Shale inhibitors are designed to minimize the interaction between water and clays to maintain wellbore integrity and help remove cuttings from the wellbore. Shale inhibitors will deplete during the drilling process and hence maintaining their concentration at the needed level is crucial. This paper presents novel, field-friendly technologies for tracking amine-based shale inhibitors.

A lab study was conducted on three different inhibitors (A, B, and C). Inhibitors A and B are successful, legacy products while inhibitor C is a new product. Inhibitors A and B are measured using a colorimetric based test. Inhibitor C required a new tracking technology; a light-scattering approach was utilized. Adsorption of the three shale inhibitors were studied by exposing them to six different shale types. Filtrates were then measured for shale inhibitor concentration to determine how much inhibitor was adsorbed onto the shale. Differences were observed in the adsorption rates of the three different shale inhibitors when exposed to shale.

Further we were able to monitor the concentration of the inhibitors in the field and compare their relative ease of maintenance based on their differing depletion rates. Data from two field cases will be presented in this paper. Overall, the new inhibitor C showed favorable performance in both lab and field conditions.

By knowing how different swelling inhibitors will deplete with different shales, we can plan accordingly and adjust the shale inhibitor concentration throughout the drilling process. Having this new shale inhibitor tracking technology available can be used to gain insight on shale reactivity in real time while drilling.

Introduction

Drilling shale formations has increased dramatically in recent years. The drilling fluid choice in these shale plays is often nonaqueous-based fluid (NAF). While NAFs can provide advantages such as shale stabilization, lubricity, and contamination tolerance, their environmental consequences and associated costs are usually an issue. Water-based fluids (WBFs) generally offer an improved environmental profile over NAFs. Additionally, costs can often be lowered with WBFs because of the reduction in costs associated with base-oil transportation, cutting transportation, and cutting remediation (Deville et al., 2011). However, shale formations tend to absorb water from the surrounding fluids, and this can cause rapid swelling or shale disintegration and wellbore instability. These water-reactive formations can cause further operational problems such high solids loading, bit balling, washouts, hole cleaning problems, high torque and drag and ultimately non-productive time and increase in costs (Van Oort, 2003). To overcome the hydration and swelling issues while drilling with water-based fluids, shale inhibitors or clay stabilizers are used to create High-Performance Water Based Fluids (HPWBF) (Santra et al., 2023).

Shale inhibitor additives for HPWBF are designed to minimize the shale inhibition performance gap between WBFs and NAFs. There are four different mechanisms by which these shale inhibitors minimize the uptake of water by the reactive shale minerals (May et al., 2020):

1. Swelling Inhibitors: These types of additives are generally low molecular weight additives that can potentially enter the pore spaces of the clays and block the charges inside the clay structure that would otherwise interact with the water molecule and start the hydration process. One frequently used chemical is an amine, which has polar functional groups such as amine (-NH_2) or ammonium (-NH_3^+) ions that allow them to interact with both water and shale surfaces (AlArfaj et al., 2023).
2. Encapsulators: These types of additives are generally high molecular weight polymeric materials that can potentially coat the surface of clay particles creating a barrier that slows the diffusion of water into the clay pore spaces.
3. Pore pressure transmission reducers: These additives create an osmotic membrane on the clay surfaces and in the clay pore spaces. This osmotic membrane can effectively reduce the invasion of water into the pore spaces of clay due to the gradience of ions on each side of the membrane. Silicates are examples of this type of additive; they achieve physical plugging of the shale pores through a process of polymerization and precipitation. Silicates form a thin film on the surface of clay particles within the shale formations. This film acts as a physical barrier that inhibits water penetration into the clay structure (Van Oort et al., 1996).

4. Anti-accretion additives: These additives reduce the tendency of water-reactive minerals to develop adhesive forces towards metal surfaces. Accretion is generally most problematic when clays reach a partially hydrated state known as a plastic viscosity state, which lies between the plastic limit and the liquid limit. Effective inhibition of clay mineral would keep it below the plastic limit, while fully dispersing the clay would push it past the liquid limit, both being effective states where clays generally do not accrete. Glycols are typically examples that harden the shale rock with the aid of potassium chloride. Glycol displaces water from the clay resulting in hard shale rock (Reid et al., 1993).

The focus of this paper will be on shale swelling inhibitors, in particular amine-based inhibitors. By design these high-performance shale inhibitors react with shale and get depleted over time. This depletion leads to a loss of the functionality these products offer. In many cases the loss of shale inhibition quality downhole triggers shale-related drilling problems that can't be resolved by the addition of more shale inhibitor product. Therefore, it is crucial to have an accurate representation of the shale inhibitor product concentration in the HPWBF being used downhole. A new means to measure the concentration of the amine-based shale inhibitors was presented recently in the literature. The test uses a colorimetric based method that measures the concentration of swelling inhibitor in the drilling fluid filtrate (May et al., 2022).

This paper presents a new shale inhibitor tracking technology that involves a light scattering approach where a turbidity-based calculation is used. The colorimetric based method and the turbidity-based method are then used to compare the performance of three different shale inhibitors using six different shale samples. The paper also presents results from field cases.

New Testing Methodology

Initial Development

We invented a new field test method for cationic amine swelling inhibitors. The principle of the test is based on the reaction of the cationic, quaternary amine of Inhibitor C with a proprietary anionic reagent. The reaction of these two compounds creates a water-insoluble salt that precipitates in a very fine, self-suspending solid in water.

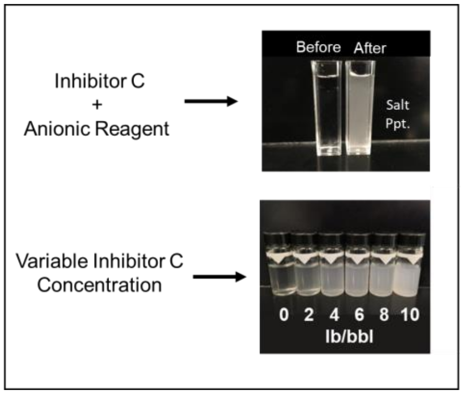


Figure 1– New precipitation-based strategy to measure amine swelling inhibitor.

The amount of precipitate that is formed is directly proportional to the amount of quaternary amine in the fluid (Figure 1). Furthermore, the amount of precipitate can be easily quantified with a turbidimeter. A turbidimeter measurement is based on light scattering principles. A source light shines on a sample and that light can be absorbed, reflected, transmitted or scattered on to or from solid particles suspended in the liquid medium. A detector positioned 90 degrees from the light source can detect any light scattered from the solids in the sample. The size, shape, morphology and chemical composition can all affect how much light is scattered from a sample. For our test samples, Figure 2 shows the relationship between concentration of Inhibitor C and turbidity in Nephelometric Turbidity Units (NTU).

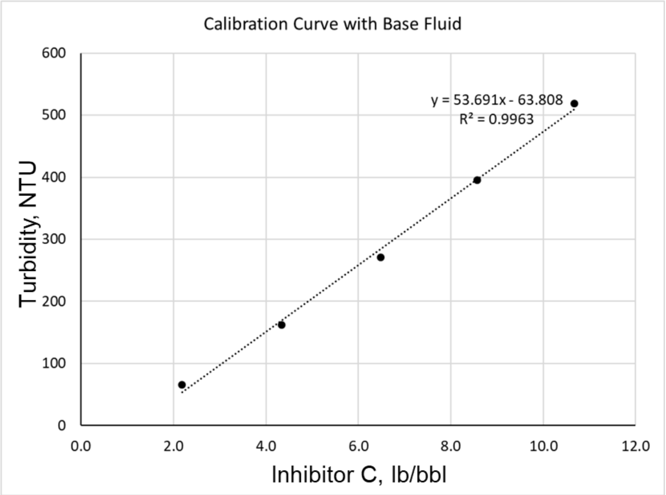


Figure 2– Linear relationship between turbidity and amine concentration.

Early development work on this new methodology showed that several interfering compounds were possible to be encountered. First, common brines used in WBFs gave variable results on the new test. Therefore, several iterations of the methodology were created until an additional reagent was identified that conditioned the sample before testing, regardless of the base brine composition. Secondly, pH sensitive amines were also found to react with the proprietary anionic regent if the sample was at a pH less than 10, again showing falsely high levels of turbidity. Thus, an additional reagent was added to the methodology to keep the pH of the sample being tested above pH 10. Additionally, other additives that were tested for potential interference were multivalent salts, corrosion inhibitors and silicates. None of these three types of additives showed interference in the test results. After the aforementioned interference testing was conducted, the basic chemical steps of the new test became: 1) acquire 1 mL of drilling fluid filtrate (to remove all drilling fluid solids); 2) treat the filtrate with a conditioning agent; 3) treat sample with pH adjustment reagent; 4) treat sample with proprietary anionic reagent; 5) measure turbidity; and 6) calculate concentration.

Mud Testing

The previous tests used very simple formulations with only a few key additives of interest in water to isolate their potential interference on the new test. Our next phase of development initiated testing the concentration of Inhibitor C in full drilling fluid formulations. Drilling fluids can become very complex mixtures with many possible additives being used depending on the challenges of the wellbore. To begin we chose three formulations routinely used in different regions of the world. However, these formulations had never included Inhibitor C. Additionally, Fluid #1 (Table 1) contained both NaCl and KCl, a black powder shale inhibitor, and already contained an amine swelling inhibitor which works by a similar mechanism to Inhibitor C. We chose to keep the amine swelling inhibitor in Fluid #1 because our previous testing efforts showed that other pH sensitive amines do not interfere with this new measurement. Further, Fluid #2 contained only KCl and a combination of a unique shale encapsulator and an anti-accretion product for shale inhibition. Finally, Fluid #3 contained only NaCl, two different shale encapsulators and a black powder product for shale inhibition.

Table 1. Representative Mud Formulations for Development Testing

Additive	Fluid #1	Fluid #2	Fluid #3
Water, bbl	0.79	0.857	0.77
NaCl, lb	72	-	75
KCl, lb	18	10.5	-
Alkalinity Agent, lb	1	0.5	0.6
Xanthan, lb	1.25	1.5	0.5
Starch, lb	5	6	-
HT Starch, lb	-	-	5
PAC, lb	2	1.25	1
Shale Encapsulator 1, lb	-	5.25	-
Shale Encapsulator 2, lb	-	-	1
Shale Encapsulator 3, lb	-	-	1
Amine inhibitor, lb	7	-	-
Shale Inhibitor C, lb	2.3-7.0	2-10	2.3-11.4
Anti-accretion, lb	-	7	
Black Powder, lb	6	-	6
Calcium Carbonate, lb	-	10	50
Barite, lb	60	100	31

Table 2. Inhibitor C concentration measurements of mud formulations

Fluid #1	#1	#2	#3	#4	#5
Inhibitor C (actual), lb/bbl	2.3	4.6	7.0	-	-
Inhibitor C (measured), lb/bbl	2.6	5.4	8.2	-	-
Fluid #2	**#1**	**#2**	**#3**		
Inhibitor C (actual), lb/bbl	2.0	5.0	10.0	-	-
Inhibitor C (measured), lb/bbl	2.0	4.9	10.0	-	-
Fluid #3	**#1**	**#2**	**#3**		
Inhibitor C (actual), lb/bbl	2.3	4.6	6.9	9.1	11.4
Inhibitor C (measured), lb/bbl	2.5	4.4	6.7	9.2	12.0

The concentration of Inhibitor C was tested between 2 and 12 lb/bbl in these different formulations. Calibration curves of Inhibitor C in each fluid's corresponding base brine were also collected. As the data shows, the actual concentrations in the mud were very similar to measured concentrations. The measured concentrations were calculated from the calibration curves generated in the base brine. These results gave good evidence that this new testing methodology was amenable to full drilling fluid formulations.

Next, we chose to vary the density of a single formulation (Fluid #1 from Table 1) to see if the test results changed due to widely varying amounts of barite weighting agent. It is possible Inhibitor C might have some adsorption affinity for barite solids. Additionally, this test is measured with drilling fluid filtrate to remove all solids from the fluids. If Inhibitor C had appreciable adsorption on to barite solids, it would be filtered out of the filtrate, and we would observe much lower measured values compared to actual concentrations.

Table 3. Representative mud formulations for development testing

Additive	Fluid #1	Fluid #2	Fluid #3
Density, ppg	**11.0**	**14.0**	**16.0**
Water, bbl	0.803	0.689	0.614
NaCl, lb	50	50	50
KCl, lb	18	18	18
Alkalinity Agent, lb	1	1	1
Xanthan, lb	1.25	1.25	1.25
Starch, lb	5	5	5
PAC, lb	2	2	2
Amine inhibitor, lb	7	7	7
Shale Inhibitor C, lb	8	8	8
Black Powder, lb	6	6	6
Barite, lb	85	250	360

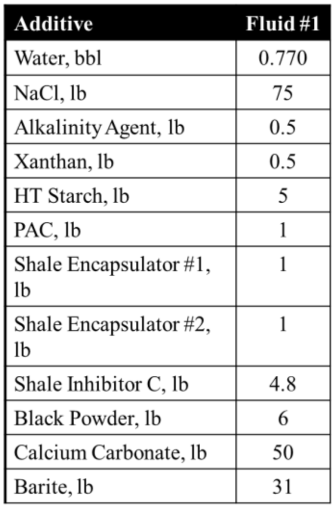
Table 4. Inhibitor C concentration measurements of mud formulations

Mud Sample	#1	#2	#3
Inhibitor C (actual), lb/bbl	8.0	8.0	8.0
Inhibitor C (measured), lb/bbl	7.5	7.9	8.5

As data in Table 4 shows, we observed little differences of the measured concentrations of Inhibitor C in the variable density fluids. These results provided good evidence that Inhibitor C is not significantly adsorbed onto barite solids.

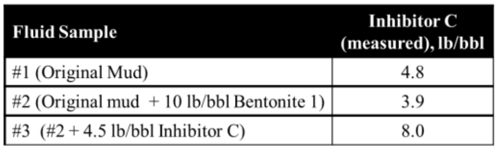
Next, we conducted an experiment of depletion followed by addition of Inhibitor C as might be done in the field. Inhibitor C should be adsorbed by highly reactive clay and shales, as it participates in cation exchange, to reduce the swelling capacity of these minerals. Therefore, an addition of reactive bentonite should lower the measured concentration of Inhibitor C as the bentonite is filtered out of fluid filtrate. Subsequently, we chose to add more Inhibitor C after the bentonite was added. Addition of Inhibitor C should also be reflected in the measured results by a measured increase in Inhibitor C concentration.

Table 5. Formulation for depletion and spiking Test



Additive	Fluid #1
Water, bbl	0.770
NaCl, lb	75
Alkalinity Agent, lb	0.5
Xanthan, lb	0.5
HT Starch, lb	5
PAC, lb	1
Shale Encapsulator #1, lb	1
Shale Encapsulator #2, lb	1
Shale Inhibitor C, lb	4.8
Black Powder, lb	6
Calcium Carbonate, lb	50
Barite, lb	31

Table 6. Depletion and spiking test



Fluid Sample	Inhibitor C (measured), lb/bbl
#1 (Original Mud)	4.8
#2 (Original mud + 10 lb/bbl Bentonite 1)	3.9
#3 (#2 + 4.5 lb/bbl Inhibitor C)	8.0

As shown in Table 6, the original mud contained 4.8 lb/bbl of Inhibitor C. A 10 lb/bbl addition of bentonite reduced the measured concentration of Inhibitor C by 0.9 lb/bbl (from 4.8 lb/bbl to 3.9 lb/bbl). This fluid also contains NaCl, two different shale encapsulators and a black powder product which also contribute to the shale inhibition quality of the fluid and may compete for sites on the bentonite clay. Next, addition of 4.5 lb/bbl of Inhibitor C raised the measured concentration of Inhibitor C by 4.1 lb/bbl (from 3.9 lb/bbl to 8.0 lb/bbl). Overall, these were positive indicators that this test could detect adsorption and additions of Inhibitor C and, thus, is a reliable measurement of Inhibitor C in water-based drilling fluids.

Overall, the initial development of this new test spanned 1.5 years of development work, interference testing, iteration, reliability testing and reagent sourcing with QAQC testing for this new test method.

Laboratory Testing

We became particularly interested in the ability of this test to quickly determine a shale inhibitor's affinity for clay and shale by simply measuring the depletion of the product. Therefore, we designed a lab study to test adsorption of three different amine inhibitors (Inhibitors A, B, and C) on six different water-reactive shale minerals. Inhibitors A and B are legacy products with proven success in the field while Inhibitor C is a newly developed product. Shale inhibitors A and B are tracked using a colorimetric based test that has been previously disclosed in the literature (May et al., 2022) while inhibitor C is tracked using the turbidity-based approach as described in the previous section of the paper. The shales were selected to have different mineralogies and reactivities. The six shales that were tested are: Bentonite 1, Bentonite 2, Grane shale, London clay, Pierre shale, and Oxford clay. The bentonites are from two different grades with differences in their reactivities. The Cation Exchange Capacity (CEC) was used to test the reactivities of the six shales selected. The results are presented in Table 7 below:

Table 7. MBT results for the reactivity of six shale samples

Shale Type	CEC Value (meq/100g)
Bentonite 1	94
Bentonite 2	74
Grane Shale	38
London Clay	34
Pierre Shale	28
Oxford Clay	18

Depletion Curves

The clays were all sieved to a size of 200 mesh or less. Different mixtures of shale inhibitor and water were mixed with the different clays to obtain the amine depletion curve for each clay with each inhibitor using the step-by-step process described below:

1. Add 7 g of shale inhibitor (A, B or C) to 350 mL of DI water using an overhead mixer
2. Add the necessary amount of soda ash to ensure that the pH of sample is between 8.9-9.1
3. Add the required clay concentration to be tested
4. Mix for a period of 30 minutes
5. Use the API filter loss cell at a pressure of 100 psi to collect the filtrate
6. Use the colorimetric based testing methods for shale inhibitor A & B and the turbidity-based testing method explained in this paper for shale inhibitor C.
7. Calculate the concentration of the remaining shale inhibitor for each sample
8. To obtain the depletion curve, plot the value of the shale

inhibitor on the y-axis vs. the concentration of clay used on the x-axis

The purpose of obtaining the depletion curves was to compare the adsorption of the three shale inhibitors. Depletion curves for each of these was plotted as shown in Figures 3, 4 and 5. The clay depletion curves show a difference in the reactivity of the six shales with the three shale inhibitors. The slope of the depletion curves corresponds to the rate of depletion. The higher the slope the faster the depletion rate of the shale inhibitor. The shale inhibitors deplete fastest when exposed to Bentonite 1 followed by Bentonite 2, Grane Shale, London Clay, Pierre Shale and finally Oxford Clay was the slowest to deplete. The order by which the shale inhibitor depletes directly follows the results obtained from the methylene blue test. By taking a closer look at the data we also noticed a difference in the adsorption rates of the three swelling inhibitors. Inhibitor C was the slowest to deplete with all six clays, Inhibitor A followed, and finally Inhibitor B was the fastest to deplete in all cases. Figure 6 summarizes the behavior of the three inhibitors with the different shale types tested. The figure compares each amine’s depletion rate as a function of the mineral type.

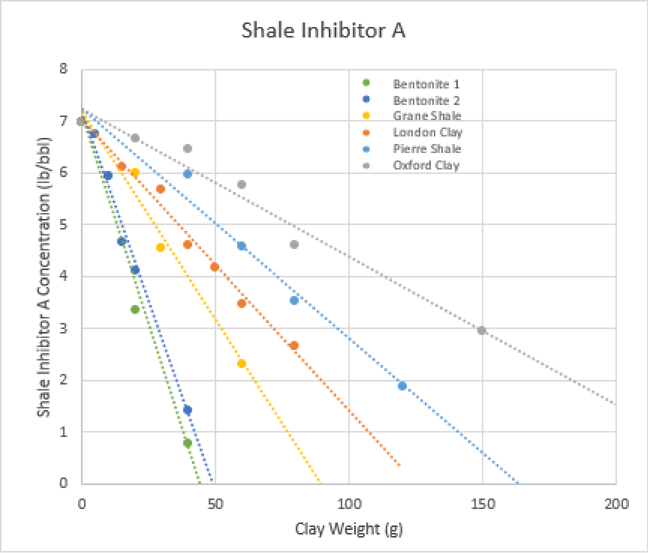


Figure 3– Shale Inhibitor A depletion curves

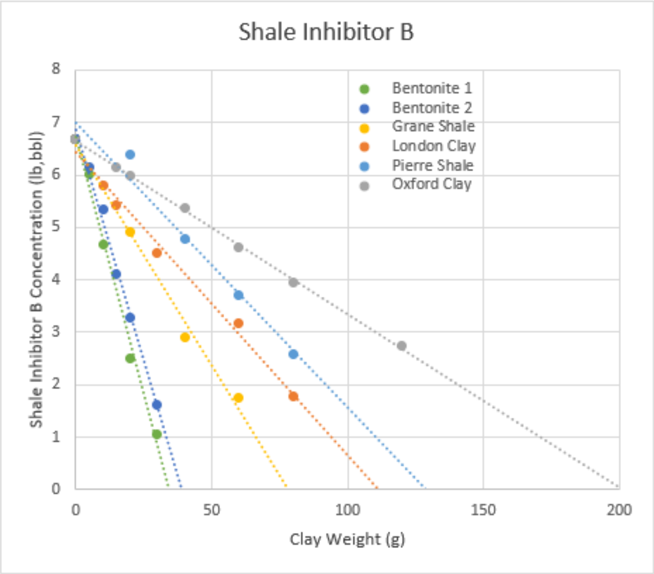


Figure 4– Shale Inhibitor B depletion curves

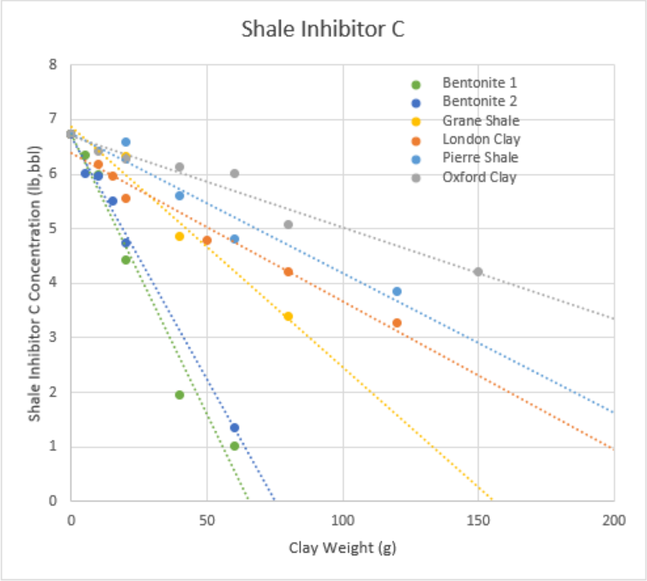


Figure 5– Shale Inhibitor C depletion curves

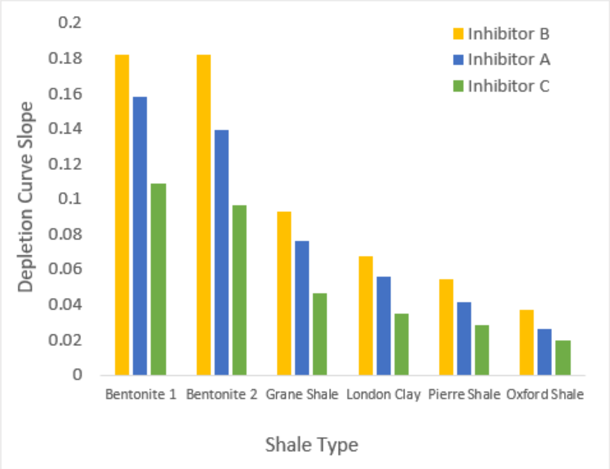


Figure 6– Summary of depletion curves for the three inhibitors tested and the six shale samples

Bentonite Hydration Suppression Testing

To further analyze the performance of the three swelling inhibitors, bentonite hydration suppression testing was conducted using Bentonite 1.

1. 7 g of shale inhibitor (A, B or C) to 350 mL of DI water using an overhead mixer
2. Add the necessary amount of soda ash to ensure that the pH of sample is between 8.9-9.1
3. Add the required Bentonite 1 amount to be tested
4. Mix for a period of 30 minutes using the over-head mixer
5. Measure the rheology profile and 30-minute gel strength of the mixture using Fann 45 viscometer

Figure 7 shows the 600 RPM viscosity profile of the mixture. There is a clear distinction between the viscosity profile when shale inhibitor was used versus a water-clay sample with no shale inhibitor added. Figure 8 shows the results and we were able to see a difference in the ability of the 3 products to inhibit the clay and prevent gelation. Inhibitor C had the best performance, followed by Inhibitor A and finally Inhibitor B.

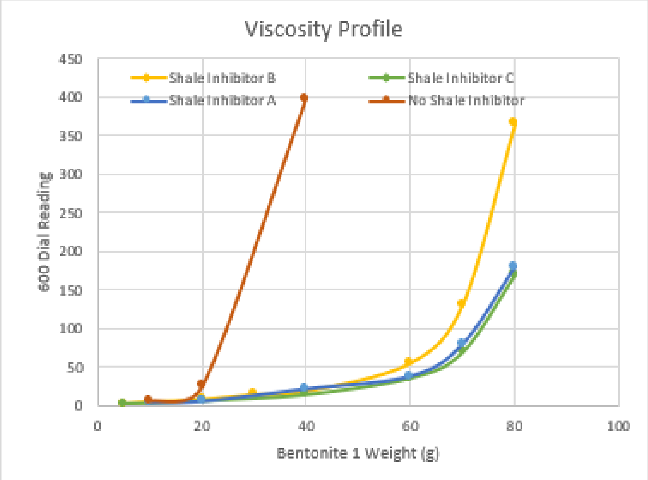


Figure 7– Viscosity profile comparison for the 600-dial reading

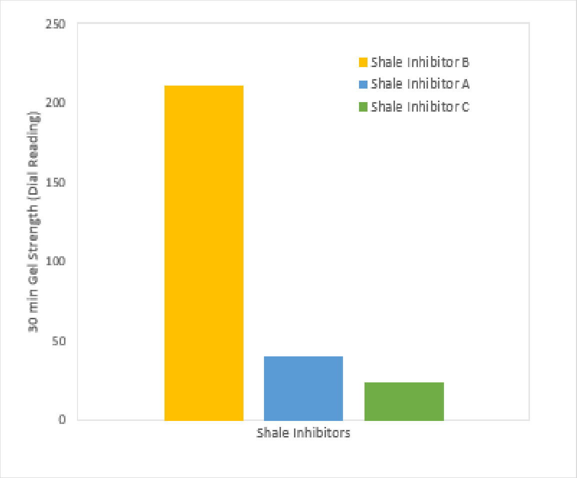


Figure 8– 30-minute gel strength comparison for the higher loadings of Bentonite 1with different shale inhibitors

Shale Inhibitor Composition

Analyzing the data gathered, we can conclude that shale Inhibitor C depletes the slowest. This can suggest that it has less affinity towards the clay than shale Inhibitor A and B. However, the data from the bentonite hydration suppression test indicate that shale Inhibitor C has the best performance. To explain these findings we looked at the concentration of the active material in each shale inhibitor. As shown in Table 7, shale Inhibitor C has the highest relative amount of active material with 2.1% active component compared to 1% and 1.1% for Inhibitor A and B respectively. The active concentration of Inhibitor C can explain, at least in part, why it depletes slower than Inhibitors A and B. The differences in the depletion and performance of shale inhibitor A and B can be explained, at least in part, due to their chemical structure. Shale inhibitor A is an oligomeric amine and has more amines per molecule compared to inhibitor B.

Table 7. Active material concentration for each shale inhibitor

Inhibitor	Active Material Relative Concentration (%)
Inhibitor A	1.0
Inhibitor B	1.1
Inhibitor C	2.1

These lab results suggested that new Inhibitor C would be as effective or better at shale inhibition compared to legacy Inhibitors A and B and that Inhibitor C may be more easily maintained in the field due to its slower depletion rate.

Field Trial Preparation

The use of this new testing methodology was used outside of our global R&D facility for the first time in 2021. We created a protype kit containing all required equipment and chemical reagents to perform the test. Additionally, insufficient training, confusion and miscommunication has been cited in the past as barriers to other new laboratory and field tests. Therefore, we created multiple training materials consisting of written, illustrative and video trainings to reduce the likelihood of operator errors when launching this new test. We sent all of the aforementioned items to a regional laboratory in the Middle East to prepare for a field trial in Qatar (Figure 9).

Figure 7– Image of prototype testing kit

First, the lab technicians self-trained using all the included training materials to ensure competency on the new test. Then they measured a series of concentrations of Inhibitor C in the base brine of the planned fluid formulation to serve as the calibration curve for the field fluid. Figure 10 shows the calibration generated.

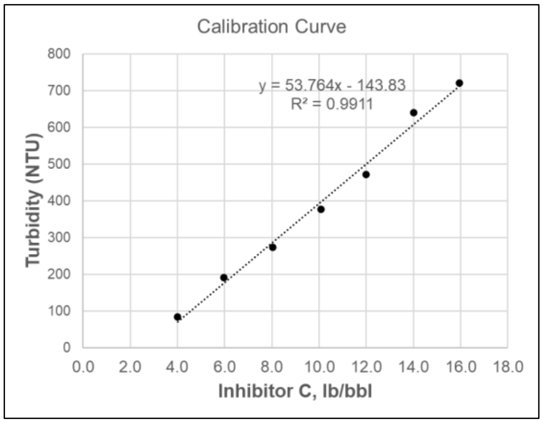


Figure 8– Calibration curve for field trial mud

Next the lab technicians created several full formulation mud samples with varying concentrations of Inhibitor C (Table 8). The amount of Inhibitor C planned to be used in the field was 6 – 9 lb/bbl. Therefore, the actual concentrations created was between 5 lb/bbl and 9 lb/bbl for lab testing. The measured concentrations that were calculated against the calibration curve in base brine compared very well with the actual concentrations in the fluid (Table 9).

Table 8. Mud formulation for field trial

Additive	Fluid #1
9.7 ppg KCl, lb	83
Water, lb	227
Alkalinity Agent, lb	1
Xanthan, lb	1.5
HT Starch, lb	6
PAC, lb	2
Inhibitor C, lb	5-9
Calcium Carbonate, lb	10
Graphite, lb	10
LCM Fiber, lb	5
Biocide, lb	0.5
Scavenger, lb	3.8
Barite, lb	37.6

Table 9. Measured concentrations of inhibitor C in mud formulations

Mud Sample	#1	#2	#3
Inhibitor C (actual), lb/bbl	5.0	7.0	9.0
Inhibitor C (measured), lb/bbl	5.1	6.8	8.8

Field Trial Results and Feedback

Qatar Trial

A field trial of the product and the tracking technology was conducted in Qatar in 2021. The fluid engineers were trained on the test and conducted the concentration tests of Inhibitor C alongside their standard fluid checks. Figure 11 shows the measured values of Inhibitor C throughout this interval. Only one addition of 2 lb/bbl of Inhibitor C was made at 2000 ft of depth. The field tracking test reflected that increase in concentration between 2000 ft and 3000 ft testing. Subsequently, the concentration of Inhibitor C remained consistent and at the designed concentration levels throughout the remainder of the interval with no further additions of Inhibitor C. Additionally, the MBT values of the active drilling fluid were less than 10 throughout this interval reflecting low reactivity mineralogy of the formation.

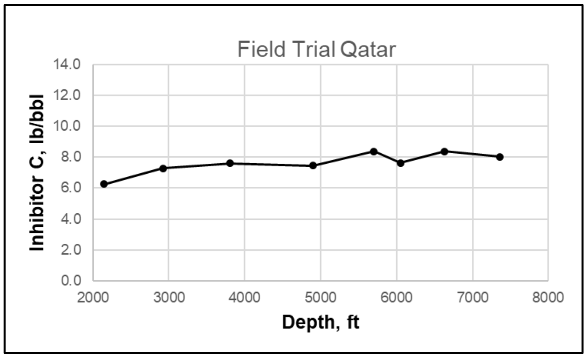


Figure 9– Inhibitor C concentrations measured in active drilling

fluid in Qatar field trial

Additional reliability tests were conducted on this trial. A standard concentration of Inhibitor C in base brine only was measured continuously throughout the trial. The result of this test is known whereas the concentration of Inhibitor C in the active drilling fluid is effectively unknown. This standard solution measured correctly throughout the trial giving additional credibility to the concentration measurements in active drilling fluid.

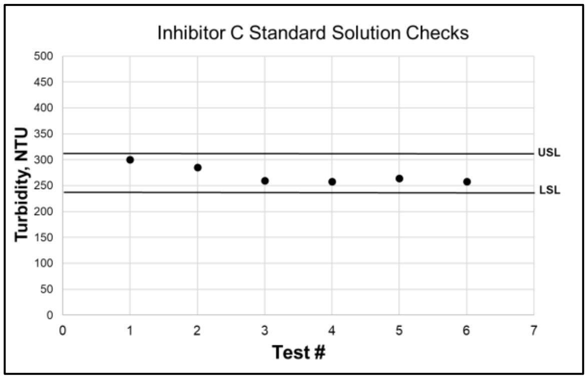


Figure 10– Standard solution of inhibitor C measured continuously throughout the trial

The field engineers reported the test was simple to perform and took about ten minutes in total.

Australia Trial

A second field trial of the product and tracking technology was conducted in Australia in 2021. The designed formulation is shown in Table 10.

Table 10. Fluid formulation for trial in Australia

Additive	Fluid #1
Water, lb	278
NaCl, lb	30
KCl, lb	30
Alkalinity Agent, lb	2.2
Xanthan, lb	0.8
HT Starch, lb	4
Inhibitor C, lb	Variable
Calcium Carbonate, lb	10
Biocide, lb	0.5
Scavenger, lb	1
Shale Encapsulator, lb	7.2
Anti-accretion, lb	10.6
HT Fluid Loss Polymer, lb	4
Lubricant, lb	2
Barite, lb	30

During pre-trial preparations, a base brine calibration curve was generated. Subsequently, the field engineer at the rig obtained a sample of field-mixed fluid without Inhibitor C. The engineer then added Inhibitor C at varying concentrations to the field mixed fluid and measured the turbidity response of each sample. A comparison of the base-brine calibration curve and field-mixed mud calibration curve is shown in Figure 13. Very good agreement between the two fluids was observed showing that we can detect the same amount of Inhibitor C in base brine and in the field mixed fluid.

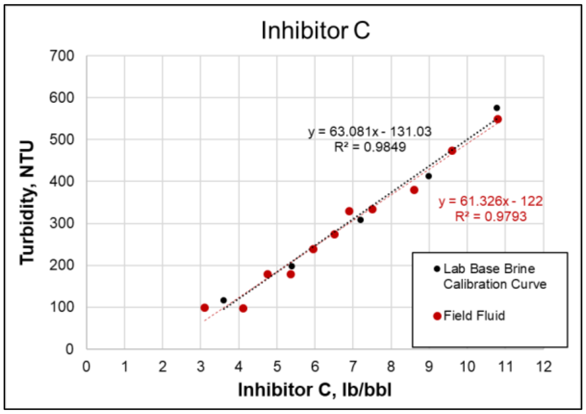


Figure 11– Variable inhibitor C concentrations measured in base brine and in field mud at the rig site

Inhibitor C levels were estimated and measured throughout a shale section of one interval. The estimated concentrations are based on mass balance of the amount of product added and the total volume of drilling fluid. Additionally, varying amounts of Inhibitor C were added frequently throughout the section. Estimated concentrations were around 6 lb/bbl through the section and measured concentrations were about 5 lb/bbl throughout the section. We observed more fluctuation in the direct measurement compared to the estimated concentration. However, mass balance concentrations do not take into account any change in concentration that may occur due to adsorption and depletion. Overall, Inhibitor C concentrations were easily maintained throughout the section as determined by both estimated and direct measurements and no problems were reported with drilling through the shale section.

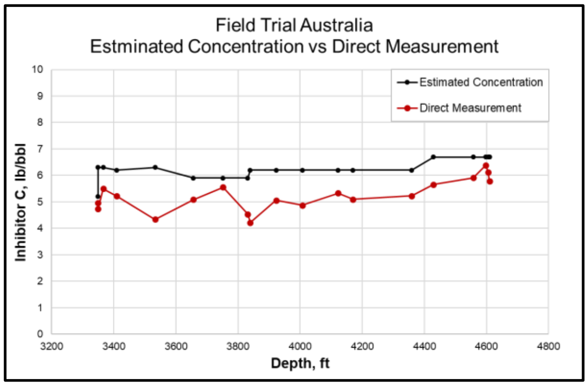


Figure 12– Estimated vs. measured concentrations of inhibitor throughout the shale section interval

Finally, a standard solution of Inhibitor C was created by the field engineer and measured continuously throughout the trial to ensure no issues with the new testing kit.

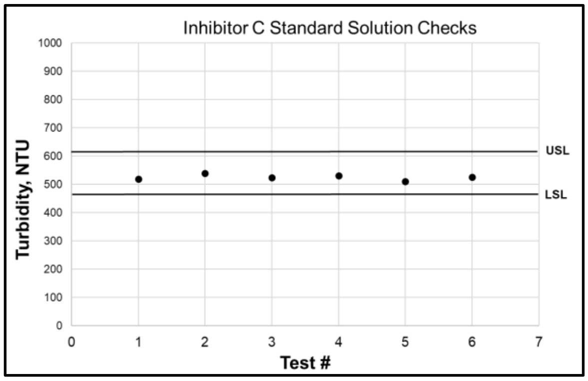


Figure 13– Standard solution of inhibitor C measured continuously throughout the trial

Conclusions

A new shale inhibitor was introduced and field tracking technology was designed and developed to measure the amount of this new shale inhibitor in active drilling fluids at the rig site. This paper highlighted the development of the tracking technology from invention to field validation. This new tracking technology was used in a laboratory study to compare the adsorption of three different inhibitors on six different clay-containing shales. Inhibitor C was found to deplete the slowest while also effectively inhibiting bentonite hydration. These two characteristics allowed us to infer that Inhibitor C may be more easily maintained in the field, due to slower depletion, while also effectively inhibiting water-reactive formations and preventing problems associated with swelling and dispersion of formation material. Furthermore, Inhibitor C and the new tracking technology were used in the field for the first time on two different trials. Inhibitor C performed as expected and concentration levels were easily maintained and confirmed with the new tracking technology.

Acknowledgments

The authors thank Halliburton for permission to publish this work.

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