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Customizing Treatment Fluids using Horizontal Drilling Cuttings to Help Prevent Formation Damage

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Abstract

This paper discusses a custom approach to developing formation-specific stimulation fluid chemistry for unconventional shale and tight-sand formations in the Anadarko basin. X-ray diffraction (XRD) and standardized clay sensitivity testing categorized the formation mineralogy and clay-fluid sensitivity. Through column fluid recovery and custom clay-control testing, the required formation-specific additives were determined and integrated into the stimulation fluid chemistry.

For the unconventional shale formation, the formation-specific surfactant recommendation was determined through column fluid recovery testing. For the tight-sand formation, work was performed to detect and confirm the presence of clay damage and then to classify the clay damage as either swelling damage or fines migration. Once the damage type was identified, custom clay-control testing was performed to determine the recommended formation-specific clay-control additive.

This study highlights a case of custom chemistry being used to help improve production in a tight-sand formation by reducing days to first hydrocarbon production by 93% and achieving an overall increase of 78% for oil production as well as a 10% increase in gas production for the first 10 months. Similar work to develop formation-specific stimulation fluid chemistry for other unconventional shale and tight-sand formations has led to preliminary results that confirm each formation requires a unique stimulation fluid chemistry to help mitigate formation damage and improve well performance.

Introduction

For these unconventional shale formations and tight-sand formations, it is key to approach these formations with a formation-specific stimulation fluid chemistry. In the past, this was done using corefloods. However, with these ultralow permeability formations, it is impossible to flow fluids through the core samples. Due to this, for several years, operators have only been relying on non-emulsion testing to screen surfactants and capillary suction times to determine clay swelling tendency. This led to many people either randomly selecting additives through trial and error or just not running the additives.

This has led to the development of a custom chemistry approach to stimulation fluids in which drilling cuttings are used to screen and optimize surfactant and clay-control selections. From these drilling cuttings, the type clay damage mechanisms can also be determined.

The objective of this paper is to discuss the methodology of the custom chemistry testing and show the value of the testing by presenting actual testing results on some Anadarko basin formations currently being drilled. For the surfactant screening, column fluid recovery testing is discussed with example results from the Woodford Shale. For the clay-control screening, custom clay testing is discussed with example results from the Cleveland tight-sand formation.

All these results lead up to a presentation of production uplift for wells in the Tonkawa tight-sand formation due to the custom chemistry approach for a formation-specific stimulation fluid to be developed.

Methodology of the Custom Chemistry Testing

Column Fluid Recovery Testing

The effectiveness of various surfactants was determined using a column fluid recovery test, which can cost-effectively and easily permit the screening of a number of surfactants in the reservoir oil and water system in the presence of a mixture of fracturing sand and reservoir rock drill cuttings. The column fluid recovery test was designed to determine the optimal surfactant choice based on fluid recovery percent and time. The column was built using produced water and a cutting/fracturing sand mixture. The packed column was then treated with a surfactant by flowing fracturing fluid through the column. Once the packed column has been treated, the fracturing fluid level was reduced to just above the packed column. Then, the column was filled with produced oil and allowed to flow. Several surfactants can be screened and ranked based on the amount of fracturing fluid recovered and time required for oil to break through the packed column.

The first step in the surfactant screening process was to evaluate the potential for emulsions to be produced by completing bench top beaker tests of mixtures of each test surfactant with produced formation water and oil. Fracturing fluid was prepared using all the additives planned to be pumped in the treatment. A mixture of broken fracturing fluid and produced oil was vigorously shaken and then timed. After a set time, the surfactant was considered to pass if no emulsion was present.

The second step in the surfactant screening process was to determine the sweep efficiency of each surfactant through a column fluid recovery test. This screening step uses formation cuttings, formation fluids (oil and water), and fracturing fluid. The cuttings were cleaned of drilling mud and mixed with 100-mesh white sand. The cuttings and sand were blended to form a 30/70 mixture of cuttings/sand. This mixture was used to make a column pack. The column pack was created by filling the column with produced water and slowly pouring the cutting/sand mixture into the column. The produced water level was lowered to just above the column bed. At this time, three pore volumes (PV) of a 50/50 mixture of produced water and broken fracturing fluid were passed through the column pack. The broken fracturing fluid contained the surfactant being screened at a concentration of 1 gal/1,000 gal. By passing three PVs of fluid mixture through the column pack, contact time between the surfactant and formation cuttings increased. The fluid mixture level was lowered to just above the column pack. Produced oil was then added to the column, and a constant oil level was maintained. Once the stopper was open, the timer was started. When oil first appeared, the timer was stopped and the fluid volume was measured **(Fig. 1).**

Fig. 1—Column fluid recovery apparatus.

Custom Clay-Control Service

The custom clay-control service assesses formation samples for clay stability with proposed stimulation fluids. Formation compatibility with stimulation fluids is imperative to ensure the maximum longevity and production efficiency of a well. This service provides a workflow designed to evaluate formation materials for potential clay-associated damage mechanisms, including swelling, sloughing, fines migration, and formation softening, which may cause increased proppant embedment. Any of these effects can contribute to loss of fracture conductivity or reservoir flow delivery across the fracture-reservoir interface. By directly monitoring the effect of clay stabilization products on formation samples, this new service workflow will output a clay treatment product recommendation as well as the recommended optimum treatment concentration.

On a well-by-well basis, this service offers well operators detailed formation information and a performance-based, optimized treatment recommendation. The testing protocol is designed to be performed in field laboratories by trained personnel using two distinct methodologies: the swelling stability test (SST) and mechanical stability test (MST) to rank all of the possible treatments. The three-step process considers the well mineralogy and source water and then ranks the performance of the clay-stabilization products.

The SST measures the swelling tendency of formation materials in the presence of a treatment fluid. This is accomplished by generating a slurry of formation material and treatment fluid and then performing a standardized test procedure to measure the degree of the formation – fluid interaction.

The MST measures the softening, fines migration, and sloughing of formation material caused by mechanical destabilization in a fluid. Ground formation materials are subjected to different treatment fluids and mechanical agitation. In a short period of time, the propensity of the sample to disintegrate and release suspended fine materials is determined by quantitative measurement. Higher measurements result from more fines release and are an indication the fluid wetting and mechanical agitation process resulted in an increase in the rate of formation destabilization. The degree of instability of the sample is monitored as a function of time and treatment; the treatment that generates the lowest MST value is indicative of the optimum formation stabilization treatment

Results

Emulsions Potential

The introduction of foreign fluids during fracturing can cause emulsions to form that can dramatically reduce the permeability in the formation, proppant pack in the fracture, or tubulars. Fortunately, it is easy to test for the potential for these emulsions to form using simple bench top beaker tests. The results indicate the combination of the various surfactants and produced oil and water does not result in any significant formation of stable emulsions.

Column Fluid Recovery Tests

The purpose of adding a surfactant to the fracturing fluid is to reduce the capillary pressure by lowering the surface tension or favorably changing the wetting contact angle of the oil phase, thus changing the wettability of the rock. Flow back of injected fluids and hydrocarbons after fracturing can be enhanced by engineering changes to how the stimulation fluid interacts with the rock and the fluids in the reservoir. The challenge is to select a surfactant, that when paired with the rock-fluid system in the reservoir and the stimulation fluid, will provide an optimum and cost-effective reduction in the surface tension without causing significant losses to the formation resulting from adsorption. To determine the bestperforming surfactant for each formation, a low-cost screening process was developed (the column fluid recovery test) that can quickly determine how several types of surfactants might react when combined with the produced reservoir oil, water, and reservoir rock (cuttings).

Three main types of surfactants were screened for this formation: surface active agents, microemulsions, and weakly emulsified surfactants. The surface active agent works by reducing surface tension and capillary pressure, which in exchange improves the treatment load recovery. Microemulsion surfactants are a unique blend of biodegradable solvent, surfactant, co-solvent, and water, which have shown to increase fluid recovery and relative permeability to oil when used in the treatment fluid (Pursley et al. 2004). Weakly emulsifying surfactants have shown to be more efficient at mobilizing oil through tight pore throats by temporarily emulsifying oil globules, which leads to more oil and gas production (He et al. 2014). Also tested was the traditional non-ionic surfactant that had typically been used in the study area. **Table 1** contains a list of the surfactants used in the column fluid recovery testing for the Woodford formation with surfactant type and ionic charge.

Table 1—List of Surfactants Screened for the Woodford Formation

Surfactant	Surfactant Type	Ionic Charge
Sample 1	Surface active agent	Non-ionic
Sample 2	Surface active agent	Non-ionic
Sample 3	Weakly emulsifying surfactant	Anionic + non-ionic
Sample 4	Surface active agent	Non-ionic
Sample 5	Microemulsion	Cationic
Sample 6	Microemulsion	Non-ionic
Sample 7	Weakly emulsifying surfactant	Anionic + non-ionic
Sample 8	No surfactant	—

The results from the column fluid recovery tests using these various surfactants are presented in **Fig. 2.** This four-quadrant chart allows for a quick screening of the results. The northwest quadrant contains the surfactants that provided the highest percentage of fluid recovery and the lowest percent of time to oil production, indicating these surfactants should produce the most favorable oil mobility results. The southeast quadrant contains the surfactants that provided the lowest percentage of fluid recovery and time to oil production, indicating these surfactants might produce unfavorable oil mobility results. Surfactants falling in the other two quadrants indicate less-than-optimum oil mobility by either demonstrating longer times to observe oil production or lower overall fluid recoveries.

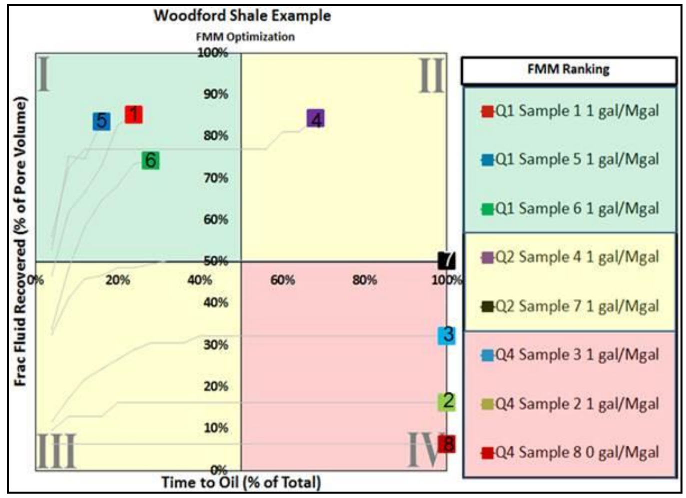

Fig. 2—Column fluid recovery surfactant screening results.

Custom Clay Control

The potential for formation damage caused by fines migration and/or clay swelling was first tested using XRD. **Table 2** shows the presence of 22% clay minerals consisting of variable amounts of kaolinite, illite/mica, and chlorite.

Table 2—XRD Analysis for the Cleveland Formation

XRD Information	Average
Quartz, wt%	57%
Albite, wt%	8%
Calcite, wt%	4%
Dolomite, wt%	3%
Feldspar, wt%	6%
Clay, wt% (illite, illite/smectite mixed layer, kaolinite, and chlorite) *	22%

XRD analyses were performed to determine the presence of clays in this tight sandstone. The custom clay-control clay SST process determined the clays in this formation did not have the swelling tendency that was likely to contribute materially to formation damage. The formation did have higher MST tendency, which would contribute to formation damage **(Fig. 3)**.

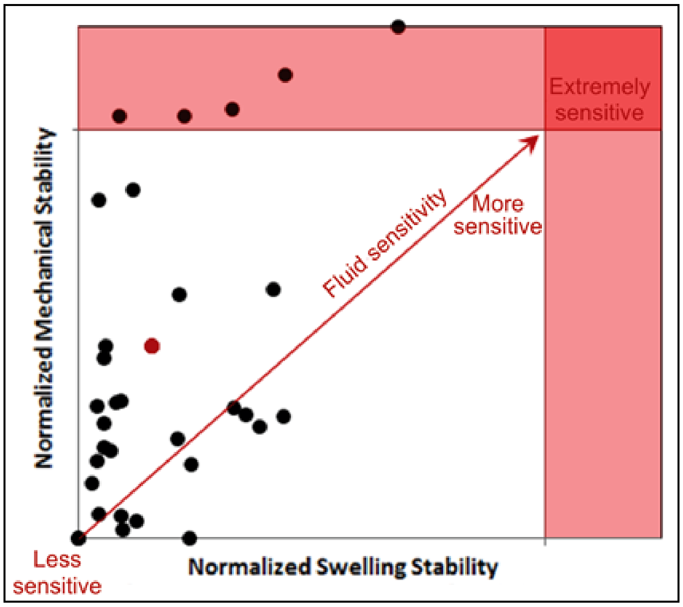

Fig. 3—Comparison of clay types in the Cleveland formations (red dot) to other formations in the Anadarko basin.

The clay-control additives were screened using both the SST and MST to determine the optimal clay-control additive based on reservoir characteristics. Both tests presented the data as a percent improvement for both SST and MST. For both tests, six clay additives were screened **(Table 3 and Fig. 4).**

Table 3—List of Clay-Control Additives Screened for the Cleveland Formation

Clay Additive	Clay Additive Type
Sample 1	Ammonium chloride
Sample 2	Ultra lightweight cationic polymer
Sample 3	Low-molecular weight cationic polymer
Sample 4	Ultra lightweight cationic polymer
Sample 5	Potassium chloride
Sample 6	High-molecular-weight cationic polymer

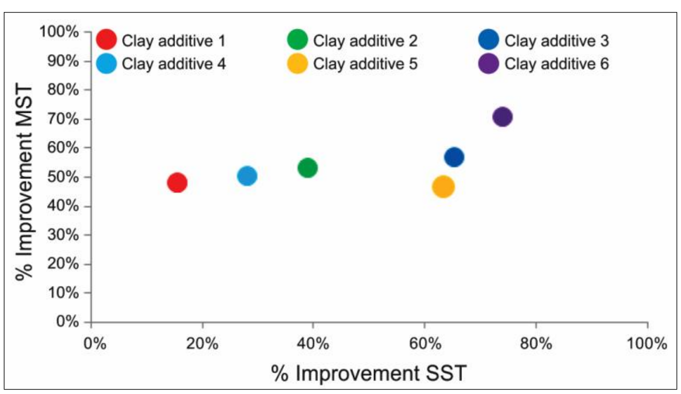

Fig. 4—Comparison of six clay-control additives based on MST and SST.

Based on the results in Fig. 4, clay additive 6 performed with highest percent improvement for swelling stability (SST) and mechanical stability (MST). To further optimize the clay-control selection, clay additive 6 was tested at multiple concentrations to determine the ideal concentration for this reservoir. For this formation, the optimal concentration is 0.25 gpt.

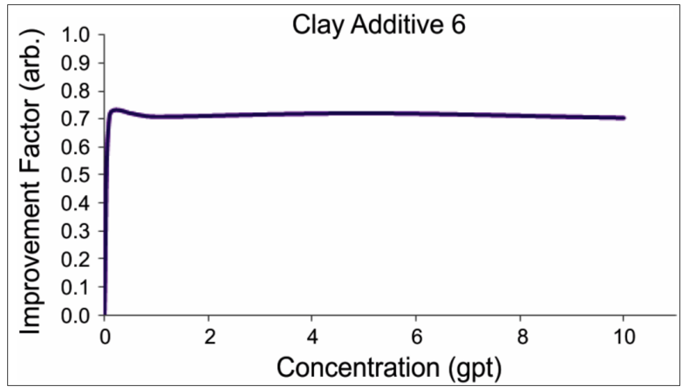

Fig. 5—Optimization of clay additive 6 by evaluating multiple concentrations to determine the breakover point, which in this case is 0.25 gpt.

By using the optimized clay additive 6 at 0.25 gpt for this formation, clay formation damage potential was reduced by 79%.

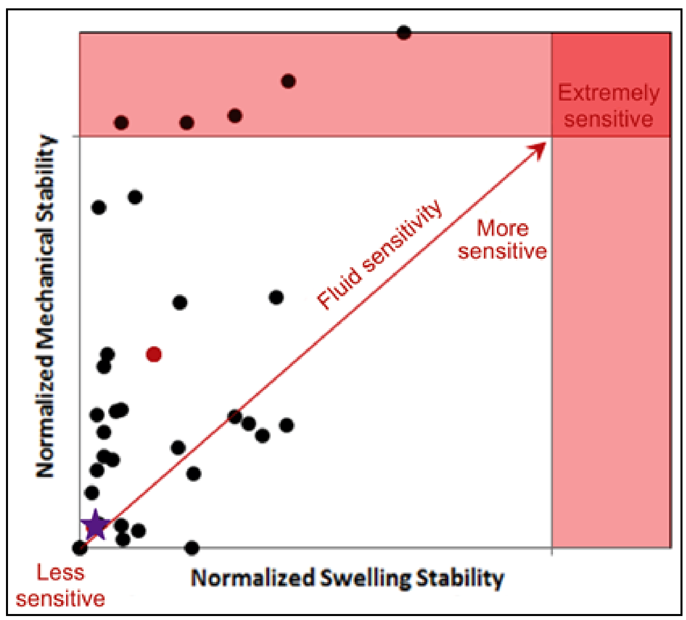

Fig. 6—Comparison of clay damage tendency before treatment (red dot) and after treatment with clay additive 6 at 0.25 gpt (purple star).

Production Uplift due to Testing and Application

In the Tonkawa tight-sand formation, custom chemistry was put to the test. Two horizontal wells were drilled and completed near each other in Dewey County, Oklahoma. The first-generation horizontal well was treated with a non-ionic surfactant and a KCl-substitute for clay control. After completing the custom chemistry testing, the second-generation well was treated with a optimized non-ionic surfactant and a low-molecular-weight cationic polymer both selected by the testing protocols.

Hourly flowback results from Well A are compared to flowback data from Well B. Cumulative oil production is normalized to 100,000 ft^2 to show the effectiveness of the customized stimulation fluid treatment.

Although the total fluid profiles appear similar, well B displayed the first measureable oil production within 35 hours of being placed on gas lift (and trace oil at 21 hours) vs. 295 hours in well A. Oil was observed in well B after only 9% of the load fluid was recovered but did not occur until 25% of the load fluid was recovered in well A. At the time this paper was written, the maximum oil rate in well B was 19 bbl/hr vs. a maximum rate of 11 bbl/hr for well A. This represents a 42% higher oil rate early in the cleanup cycle. At 30% of the load fluid recovered, well B had produced 2,358 bbl of oil compared to only 314 bbl for well A. Stated another way, well B produced 7.5 times the oil that well A produced at an equivalent point in time in the cleanup cycle. This difference in flowback performance is further accentuated by the fact the net pay in well B is less than 0.6 times (54 ft vs. 90 ft) that of well A. The results clearly show the customized stimulation treatment employed on well B resulted in achieving oil production earlier and at higher initial production rates.

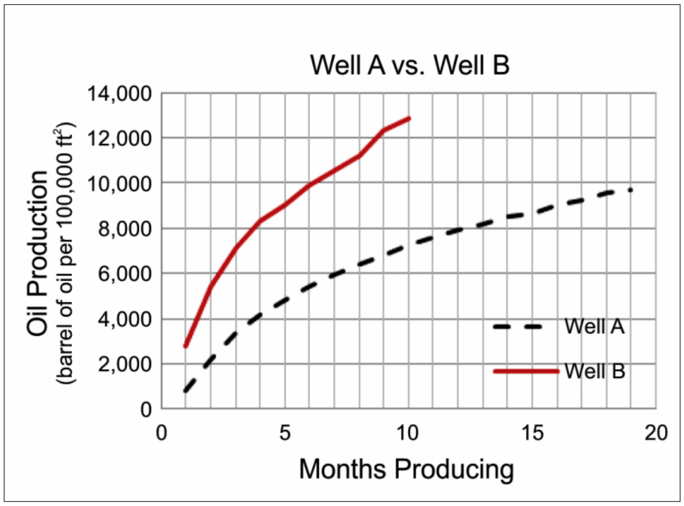

Fig. 7—Comparison of well A (non-customized fluid system) and well B (customized fluid system). Well B showed 78% higher oil production per 100,000 ft^2 than well A.

Over time, well B produced 78% higher oil production than well A after 10 months of production.

Conclusions

- Determination of optimal surfactants and clay damage potential by conventional coreflood tests is difficult for tight formations and shale.
- Advances in surfactant technology have shown to improve fracture cleanup and increase production.
- A small amount of swelling or migrating clay can potentially cause skin damage near the wellbore to formation path.
- New test methods help screen surfactants and help determine potential clay damage type and screen clay-control products for use in low permeability reservoirs.
- These new tests can be performed using drill cuttings inexpensively.
- Case studies have shown 78% increases in oil production by using customized fluids.

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