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Crude Oil Production Activation for Drill-in Operations, a New Approach to Drill-in Fluid Design

Lirio Quintero, Stephen Vickers, Tom Jones and David E. Clark, Baker Hughes Drilling Fluids

Abstract

The invasion of water-base drill-in filtrate into a producing formation reduces its relative permeability thereby restricting crude oil production. Even with excellent particle bridging design, filtrate continues to invade the permeable pore spaces reducing crude oil productivity. This reduction in flow capability appears to be the result of the adsorption of hydrated polymer from the drill-in fluid onto the formation rock. The adsorbed polymer, combined with the flow initiation pressure required to remove the internal and external filter cake (lift-off pressure) and permeability lost due to in-situ filtrate-in-crude oil emulsions, can result in significantly lower production levels. Production loss is most evident in open hole completion applications.

The laboratory proof of concept and subsequent field applications using a new damage prevention additive confirm that specially designed chemistry for water-base drill-in and completion brine can improve crude oil recovery. This new approach enhances previous drill-in fluid designs by minimizing the negative effects of filtrate invasion. The water-base drill-in fluid concept minimizes adsorption of natural and synthetic polymers onto pore rock and also reduces the possibility of pore plugging by in-situ emulsions between invaded filtrate and reservoir fluids. In addition, the new chemical design minimizes the inter-particle attractive forces in the filter cake to facilitate the direct removal of bridging and drill solids in the near-wellbore region which reduce lift-off pressures.

Introduction

The factors affecting a producing reservoir's rate of hydrocarbon recovery are varied. Likewise, the factors contributing to formation damage are many and often not known. Although the drilling fluids industry has made significant improvements in reservoir fluid design, loss of production due to filtrate fluid-inflicted damage persists.

In the early 1990's, fluids suppliers reverted to simple drill-in fluid designs having fewer components. This approach eliminated product blends that were better suited for non-reservoir drilling which, in turn, eliminated many damaging additives. The simple designs were primarily composed of brine, a biopolymer viscosifier, modified starch and sized salt or sized calcium carbonate. These specialized fluids were classified as "reservoir drill-in fluids" because they were only used to drill the payzone.[1]

From the late 90's to the present, emphasis has been placed on optimizing the particle size distribution (PSD) of the sized salt or sized calcium carbonate to bridge the distribution of reservoir pore diameters. Advances in PSD selection have led to improved pore bridging and filter-cake deposition. This approach has reduced spurt and total fluid loss volumes and led to thinner filter cakes.[2, 3, 4, 5] Bridging calculators have been developed to assist in reservoir fluid design, especially when rock characteristics are known. Overall, operators have been very pleased with production figures using this approach, particularly in open-hole completion applications where the practice of perforating beyond the skin damage is not performed.[5]

During the same time period, formation damage laboratories were learning more about the effects of biopolymer viscosifiers and modified starches on reservoir rock.[6, 7] Core analysis using ESEM and cat scan technology have assisted researchers, allowing them to identify the extent of damage resulting from polymers deposited in the pore spaces. Some operators have recommended changes in polymer selection and an increased focus on preventing pore blocking.

Despite the advances in filter cake development and polymer selection, operators have continued the search for ways to increase levels of crude oil production. One frequently overlooked, but significant, damage mechanism is the production loss caused by water blockage.[6, 8, 9, 10] This loss of production due to water blockage and hydrated polymer is a by-product of filtrate invasion. Damage from filtrate invasion, especially from the formation fluid compatibility perspective, has been studied extensively.[11, 12] Designing a drill-in fluid to address compatibility is commonly practiced; however, fluid design to prevent loss of permeability caused by the water absorption phenomenon is an area that should receive more attention.

The ideal scenario for adsorbed in-situ filtrate removal would be for the production crude oil and condensate to flush the trapped water from the payzone during production. Many hours of core flood tests in the laboratory and numerous field studies confirm that invaded filtrate and polymer remains in the formation pore throats. In fact, the high capillary forces and the water retention phenomenon make it virtually impossible to expel the retained water with simple production. However, if the interfacial properties between the filtrate and formation fluids could be altered, some measure of the relative permeability could be recovered.

Advances in surfactant chemistry and technology have permitted development of new drill-in and completion fluid designs that offer, at least, a partial solution for the removal of water and hydrated polymer blockage. One such surfactant has now been laboratory and field tested. Test results confirm that the surfactant molecule is small enough to enter the pore spaces with the filtrate during the spurt loss period and continuously during and after the dynamic cake deposition period. Likewise, studies confirm that in zones susceptible to emulsion formation, this surfactant prevents such emulsions without altering the wettability of the rock surface. Furthermore, measurements of the surface tension of water-base drill-in fluid (DIF) filtrates suggest that the interfacial properties of the invaded filtrate and in-situ fluids is reduced and that hydrated polymer adsorption on water-wet reservoir rock in minimized. The net benefit of this phenomenon is increased crude oil mobility during production.

The following laboratory studies and field results confirm the benefits derived by including a specially designed (SD) surfactant in water-base drill-in fluid and completion brine as a means of minimizing water, hydrated polymer and emulsion blocks in pore spaces.

Laboratory development

Fluid formulations and tests procedures

The effect of the SD surfactant on fluid properties of water based drill-in fluids was evaluated in concentrations ranging between 0.25 and 1.0 % by volume formulated with SD surfactant additive using a Fann 35A viscometer, dynamic filtration equipment and Particle Plugging Apparatus (PPA).

The prevention of crude oil emulsion was evaluated using bottle tests. The tests were performed using drill-in filtrate or completion brine and crude oil. These tests were made with various crude oils having °API gravities of 10, 15.5, 26 and 32. The brine formulations evaluated were KCl, NaCl and $CaCl_2$, with densities up to 11.2 ppg. The concentration of specially designed surfactant additive was evaluated between 0 and 0.5% (v/v) for aqueous phase/crude oil ratios of 25/75, 50/50 and 75/25. Samples were mixed and placed in a water bath at constant temperature where fluids separation as function of time was measured.

Return permeability tests, using a standard Hassler Permeameter and Berea sandstone cores, were made at 500 psi differential pressure and temperatures up to 200°F (93.3°C). The tests were made using a solid-free drill-in fluid in order to study the effect of SD surfactant in a porous media invaded by the water-based drill-in.

Laboratory tests Results

Fluid properties

The evaluation of the SD surfactant additive on drill-in fluid was made on samples that were mixed and hot rolled at 180 F (82.2°C) for 16 hours. The formulations and rheological properties presented in **Table 1** indicate that the SD surfactant additive does not affect the rheological properties, except for a minimal increase in yield point. The sample with a concentration of 1% of SD surfactant generated similar rheological properties to the sample with 0.5%, which indicates that the SD surfactant additive exhibits no noticeable concentration effect on the rheological properties.

The filtration properties of the formulation DIF 2 of Table 1 was evaluated and showed very low spurt loss (0.2 mL) under static and dynamic test conditions. The total volumes in the static and dynamic filtration ranged between 6 and 7.8 mL (see **Table 2**).

Emulsion risk

The results of emulsion separation of DIF filtrate-in-crude oil and brine-in-crude oil emulsions are presented in **Tables 3 and 4**. These tests made with various crude oils at temperatures ranging from 70 to 150 °F (21 to 65.5°C) show that the SD surfactant induced emulsion breaking in light, medium and heavy crude oils.

The samples without the surfactant additive do not show good separation of the emulsion. In this case, the emulsions could remain stable for a long period of time and, as a consequence of their high viscosity, could reduce the relative permeability of the formations.

Also, the brine/crude oil proportion of the emulsions has an effect on their stability. As shown in **Table 4**, the increase of oil proportion in the emulsion results in an increase in required time for a total separation.

Figure 1 shows the fluids separation of 10.2 ppg calcium chloride brine-in crude oil emulsion mixed with 50/50 fluids proportion and evaluated at 140°F. The results show that the sample without SD surfactant does not have any fluid separation, which remain invariable for a few days of tests. The addition of 0.3% SD surfactant to this brine generates a total fluid separation in one-hour test. These results indicate that this crude oil will not generate emulsion with the brine formulated with 0.5% of surfactant.

Figure 2 shows results after the 90-minute test with a 50/50 ratio of 9.5 ppg NaCl brine and heavy crude oil. The sample with 0.25% surfactant shows partial separation and required 0.5% of SD surfactant to obtain a total separation of the fluids in 90 minutes. These results indicate that this crude oil will not form an emulsion with the brine formulated with 0.5% of surfactant.

The concentration required in order to obtain good phase separation was 0.25% for the majority of crude oils. It is recognized in the oil industry that heavy crude oils tend to promote very stable emulsions in porous media.[13] Tests with heavy crude oil, including a 10 °API gravity oil, required a concentration of 0.5% to achieve a fast separation. This sample also exhibited good surface cleaning of graduated cylinders, an indication of good water-wet properties.

Return permeability

The return permeability results of a solid-free drill-in formulated with and without SD surfactant are shown in **Table 5**. The percentage of return permeability obtained with test conditions of 500 psi differential pressure and 150°F (65.5°C) temperature was 81% with the DIF formulation contains the SD surfactant. The same formulation without the SD surfactant showed only 16.9% return permeability. The result of high return permeability with the sample formulated with SD surfactant can be attributed to the surface activity of this additive on reduction of the residual water layer and polymer adsorption.[6]

Surface tension

The results of the surface tension measurement of fresh water DIF containing biopolymer and modified starch (**see Table 6**) shows a little surface activity, only reducing the surface tension of the water from 71.6 to 53.6 mN/m. However, the addition of 0.5 g/L of the SD surfactant to this DIF formulation resulted in a moderate surface tension, reducing it from 53.6 to 29.1 mN/m. The surface tension affects the in-situ emulsion formation. Very low surface tensions are not desirable because it could promote emulsification, but a moderate reduction of surface tension promotes the mobility of flow in porous media by altering the capillary pressure.

Field applications

Field Trial 1

In a recent open-hole gravel pack application, an operator was forced to initiate post-gravel pack stimulation techniques to initiate production. Before the next well, drill-in fluid filtrate and completion brine studies were evaluated with the specially designed surfactant additive to ensure prevention of in-situ crude oil emulsions.

Emulsion tests with crude oil from the field trial 1

DIF-in-crude oil emulsions

The SD surfactant was evaluated with the 15.5 °APII crude oil and the drill-in filtrate and with completion brine. **Table 7** shows the composition and properties of the drill-in fluid. **Table 8** gives the properties of the crude oil.

The first set of tests was performed using a drill-in fluid filtrate/crude oil ratio of 50/50, and the concentration of surfactant was varied from 0 to 0.25% (v/v). The tests with 0.1% and 0.25% surfactant, as well as the one without surfactant, showed rapid phase separation, indicating no emulsion formation. However, as seen in the **Figure 3** photograph there is evidence of better separation in the sample that contains 0.25% SD surfactant.

Figures 4 and 5 show the phase separation and the graduated cylinders for tests conducted at 50/50, 75/25 and 25/75 drill-in filtrate/crude oil. The results indicate that the 3 samples with 0.25% surfactant reached total separation in less than 30 minutes. The test without surfactant in shows 96% of drill-in filtrate separation. However, these results indicate that the potential risk for emulsion formation can be eliminated with only 0.25% of the SD surfactant additive.

Brine-in-crude oil emulsions

The effect of the surfactant concentration on 9.0 ppg NaCl brine/crude oil separation was evaluated using the following conditions:

(1) brine /crude oil ratio of 50/50
(2) brine with 0.2% SD surfactant/crude oil ratio of 50/50
(3) brine with 0.2% SD surfactant/crude oil ratio of 75/25

Figures 6 and 7 show the results of the tests with 9.0 ppg NaCl brine. Both samples (brine and brine with SD surfactant) show a total separation of the fluids within the first few minutes after mixing. This indicates that this crude oil does not generate emulsion with the brine used for completion. However, the sample without the SD surfactant showed high affinity of the crude oil to stick onto the glass wall, which is a consequence of the poor hydrophilic surface generated by the brine. The cylinder with the SD surfactant has a very hydrophilic surface which results in water wet surface. The clarity of the glass in Figure 6 demonstrates this performance.

The fast separation of the drill-in filtrate/crude oil and brine/crude oil results from the interaction between the drill-in and completion fluid with a crude oil that has a relatively low concentration of the type of molecules that promote water-in-crude oil emulsions. This assumption is based on the reported low acid number. The acid number is typically associated with the macromolecules called natural surfactants.

Field Trial 1 Operations

The 6-1/8" horizontal section was drilled to measured total depth at 6,793 feet and a total vertical depth of 4,220 feet, using the fluid formulation described in **Table 7**. Then, the drill-in fluid was displaced by a 9.1 lb/gal sodium chloride brine containing 0.25% of SD surfactant and the 933 ft of the hole section was completed with a gravel pack operation.

The SD surfactant prevented emulsion blockage, but also seemed to slightly reduce the capillary forces imparted to the filtrate. The production of the well is 750 BOPD, which represents a 50% increase in production relative to expected production. . In addition, the well produced a higher amount of gas (6.5 million cu ft/day) compared to the offset wells. It was the best gas producer in the field. The operator saved approximately $100,000 that would have otherwise been spent for stimulation.

Field Trial 2

Upon investigation, it was discovered that core samples from a field in the North Sea were very susceptible to damage when exposed to the proposed well fluids in return permeability tests. Analysis of the damage core samples using a Scanning Electron Microscope (SEM) revealed that part of the reduction in permeability was due to the formation of blocking emulsions. A re-formulation of the well fluids was initiated in order to improve in the poor return permeability. A major contribution to the low return permeability was the formation of blocking emulsions. These blocking emulsions had formed when the DIF filtrate had come into contact with the in-situ reservoir fluids.

It was decided to introduce the SD surfactant into the drilling fluid formulation to improve the productivity by reducing the formation of these blocking emulsions within the porous media. The reformulated DIF and completion fluids were then run on the permeameter again, with new cores. This time the results showed a marked improvement. The return permeability of the core with the DIF plus SD surfactant had increased by 30%. SEM photos indicated that no blocking emulsion had formed within the core pore spaces. Due to a confidentiality agreement with the operator, we are not able to show the SEM photos but the following is a quote from the operator's laboratory: *"No emulsions or other fluid damaging mechanisms were observed."*

The knowledge gained in the laboratory testing was then transferred to the field. The operator wanted to drill 500 ft of horizontal section at a depth of 8,600 ft. This was achieved without any hole related issues using the fluid formulation described in **Table 9**. This formulation had been tested previously and verified in an external laboratory with only a 10% loss in permeability. The DIF was then displaced with a solids-free fluid very similar to the DIF, but without any calcium carbonate to reduce the chance of the gravel pack screens being blocked while they were run into the open hole. The casing was displaced to a clear brine.

The gravel pack was successfully achieved with a 100% placement of gravel in the open hole. Upon completion, the well produced 50 Mmscfd, which was in the middle of the predicted 40- 60 Mmscfd production range that the operator expected. As the expected production of the well was achieved, we can assume that the reservoir was undamaged, and the addition of the SD surfactant prevented the formation of any damaging blocking emulsion, as had been previously experienced.

Field Trial 3

Field Trial 3 involved a North Sea reservoir composed thick sections of water-sensitive clay layered between unconsolidated sandstone. The operator's reservoir engineers suggested a gravel pack to control sand production ensure the well longevity. However, laboratory data and previous experience in the field strongly suggested drilling-in with an oil-based system, rather than a water-based system. After much discussion and laboratory work, the operator decided to drill the reservoir with an OBM and then displace the well to water based, open hole spot. The completion screens were to be run and the interval displaced to clear brine and gravel packed.

A laboratory project was initiated to design a spacer system and a brine-based, open hole, spot formulated with the SD surfactant to prevent emulsion or sludge formation by the interaction of brine with the OBM and OBM filter cake. Additionally, the design included fluid loss control to enable the gravel pack.

Compatibility tests with the brine-based displacement fluids and the proposed OBM were conducted to determine their emulsion forming potential. The initial screening results indicated that emulsions would be formed if the brine was not treated. Screening tests with different treatment levels of the SD surfactant confirmed that the emulsion potential could be avoided. It was determined that 0.75% volume would be sufficient.

The next phase of testing was to determine if the 0.75% treatment level did not adversely impact fluid loss control, a prerequisite for pumping gravel.

Figures 8 and 9 show test results that included a series of dynamic and static mud-off periods and displacements, in a Hassler Cell Permeameter, beginning with the OBM and ending with the completion brine, over a 38 hour exposure period. The objective of these tests was to determine if the open hole spot design, when treated with the SD surfactant, would maintain fluid loss control on the core face while also maintaining reservoir permeability.

The sequences for the two tests are given below.

1. 1-hr dynamic OBM mud placement on core
2. 16-hr static mud placement
3. 1-hr dynamic mud placement
4. Base oil spacer
5. Viscous push pill
6. Low solids open hole spot placement (dynamic)
7. Low-solids open hole spot placement (static)
8. Low-solids open hole spot displacement
9. Completion brine placement

The permeameter test that included 0.75% of the SD surfactant in the open hole, water-based spot was able to maintain fluid loss control for the entire test period **(Figure 8)** and resulted in a return permeability of 75%. The second test **(Figure 9)** is included to demonstrate the effect of an over-treatment of SD surfactant. This test included 1.25% of the SD surfactant in the open hole spot. The results indicated that increased filtrate flow began to occur 2 hours after the spot was placed across the core face, because the higher level of SD surfactant weakened the filter cake. However, as in the first test, the addition of SD surfactant to the displacement pill prevented the development of viscous interfaces (emulsion and sludge.

An OBM design with a density of 10.3 lb/gal which had been previously approved in the laboratory, was used in the field to drill a near horizontal drain section of 450 ft. After drilling the sand and clay sections without instability problems, the OBM was displaced with a base oil pill followed by a viscosified push pill. Then, the open hole was displaced to a NaBr/NaCl water based spot having 0.75% of the SD surfactant. The fluid formulations can be found in **Table 10.** The displacements were performed in the same sequence as described above. The screens were run to bottom and the well was successfully gravel packed.

A second well was drilled and gravel packed using the same formulations and procedures described above. Both wells are flowing at a rate of 22,000 BOPD, which it is 2000 BOPD more than expected. These successes can be attributed to two factors: (1) fluid designs that allowed for OBM reservoir drilling and (2) SD surfactant additions to the water based displacement and completion fluids that prevented emulsion and sludge formation and preserved near wellbore permeability.

Conclusions

- The specially designed (SD) surfactant effectively prevents the formation of in-situ filtrate and brine-in-crude oil emulsions. These emulsions, if formed after the invasion of drilling and/or completion fluids, can be a major source of formation damage.
- The addition of the SD surfactant in water base drill-in and completion fluids results in an increase in relative permeability when compared to the same fluids without the SD surfactant additive.
- SD surfactant in polymeric drill-in fluids minimizes formation damage by reducing the water saturation and minimizing the binding of hydrated biopolymers and starches to pore surfaces.
- Results obtained with the samples that contained the SD surfactant indicate that this additive does not negatively affect the water-wet reservoir rock. This is demonstrated by treating a glass sample with the SD surfactant and observing the reduced adhesion of crude oil onto the hydrophilic surface of the glass.
- The rapid separation of fluids during emulsion tests for field case 1 results from the interaction between the drill-in and completion fluid with a crude oil that has a relatively low acid number. The acid number is associated with the macromolecules called natural surfactants, which are responsible of stabilizing the water-in-crude oil emulsions.
- The application of the SD surfactant allows OBM and WBM fluids to be utilized in the same drilling and completion operations. The use of both fluid types enables the operator to gravel pack wells with high clay content without causing productivity impairment.

Acknowledgments

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Nomenclature

SD = *specially designed*
DIF = *drill-in fluid*
WBM = *Water Based Mud*
OBM = *Oil Based Mud*
SEM = *Scanning Electron Microscope*
NaCl = *sodium chloride*
KCl = *potassium chloride*
NaBr = *sodium bromide*
CaCl2 = *calcium chloride*
BOPD = *barrels of oil per day*
MD = *measured depth*
TVD = *true vertical dept*
Mmscfd = *million cu ft/day*
mN/m = *Milinewton/meter*
HPHT = *High pressure high temperature*
ft = *feet*
°F = *Temperature in Fahrenheit*
°C = *Temperature in Celsius*

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Tables

Table 1 Drill-in Fluid Formulations

	DIF 1	DIF 2	DIF 3
Water, bbl	0.879	0.874	0.869
NaCl, lb/bbl	42.6	42.6	42.6
Biopolymer, lb/bbl	1.5	1.5	1.5
Modified starch, lb/bbl	6.0	6.0	6.0
SD surfactant, %(v/v)	-	0.5	1.0
Calcium carbonate, lb/bbl	47.5	47.5	47.5
Properties			
Plastic viscosity, cP	13	13	12
Yield Point, lbf/100 ft^2	24	28	29
3 rpm reading	8	9	9
10-sec/10-min Gels, lbf/100 ft^2	9/11	10/11	10/11

Table 2 Filtration Properties of DIF 2, Measured at 180 ºF, 500 psi with a 5-µm Ceramic Disc

Filtration tests	Spurt, mL	Total volume, mL
HPHT API	-	6.0
Static filtration (PPA)	0.2	6.6
Dynamic filtration	0.2	7.8

Table 3 Emulsion Tests with DIF Filtrate and Crude Oil

Sample+ % of surfactant	W/O emulsion	Results with 26 °API Crude Oil
DIF	50/50	No phase separation of w/o emulsion
DIF+0.25%	50/50	95% separation in 20 min. Total separation in 60 min.

Table 4 Emulsion Tests with Brine and Crude Oil

Sample+ % of surfactant	W/ O emulsion	Results with 26 °API Crude Oil
Brine	75/25	Total separation in about 1 hr Crude oil stuck to glass wall.
Brine+0.25%	75/25	Total separation in less than 10 minutes
Brine	50/50	Minimal separation: (8%) after 18 hours.
Brine+0.25%	50/50	Total separation in less than 20 minutes
Brine	25/75	Minimal separation of w/o emulsion
Brine+0.25%	25/75	Total separation in about 1 hour

Table 5 Return Permeability Tests

	DIF with SD surf.	DIF without SD surf.
Core sample	Berea	Berea
Temperature, °F	150	150
Differential Pressure, psi	500	500
Initial permeability, mD	280.2	229.4
Final permeability, mD	201.9	38.8
Return permeability, %	72.1	16.9

Table 6 Effect of SD Surfactant on DIF Surface Tension

Sample	Conc. of SD surfactant, (g/L)	Surface Tension, (mN/m)
Water	-	71.6
DIF	-	53.6
DIF with SD surf.	0.1	36.3
DIF with SD surf.	0.25	30.6
DIF with SD surf.	0.5	29.1

Table 7 DIF Formulation and Properties use in Field Trial 1

Additives for 1 bbl of WBM DIF	
KCl, lb/bbl	4
Xantan gum, lb/bbl	1.25
Modified starch, lb/bbl	7
SD surfactant, % (v/v)	0.25
Glycol, % (v/v)	2
Biocide, lb/bbl	0.15
Calcium carbonate, lb/bbl	48
Properties	
Density, lb/gal	9.1
Plastic viscosity, cP	13
YP, lbf/100 sq ft	16
10-sec/10-min Gels, lbf/100 sq ft	8/10
API filtration, mL	3.6-3.8

Table 8 Crude oil Properties: Field Trial 1

Properties of Crude Oil	
°API	15.5
Viscosity @ 150 °F, cP	21
Asphaltenes, wt %	10 – 14
Paraffins, wt %	5.5 – 12
Acid number, mg KOH/g	0.30 – 0.84

Table 9 Drill-in Formulation used in Field Trial 2

Additives for 1 bbl of WBM DIF	
NaCl/KCl brine , bbl	0.9
Xantan gum, lb/bbl	1
Modified starch, lb/bbl	6
SD surfactant, % (v/v)	1.25
Glycol, % (v/v)	3
Calcium carbonate, lb/bbl	50
Properties	
Density, lb/gal	9.7
Plastic viscosity, cP	18
YP, lbf/100 sq ft	26
10-sec/10-min Gels, lbf/100 sq ft	8/10
API filtration, mL	3.0-3.8

Table 10 Drill-in Formulations used in Field Trial 3

Additives for 1 bbl of OBM DIF	
Base oil, bbl	0.58
Emulsifier, lb/bbl	8
Organophilic clay, lb/bbl	7
Water, bbl	0.26
$CaCl_2$, lb/bbl	24
Barite, lb/bbl	82
Calcium carbonate, lb/bbl	50
Additives for 1 bbl of Push Pill	
NaCl/NaBr brine , bbl	0.9
Xantan gum, lb/bbl	2
SD surfactant, % (v/v)	0.75
Additives for 1 bbl of Low Solids WBM	
KCl/NaCl/NaBr brine , bbl	0.9
Xantan gum, lb/bbl	1
Modified starch, lb/bbl	6
SD surfactant, % (v/v)	0.75
Glycol, % (v/v)	3
Calcium carbonate, lb/bbl	30

Figures

Figure 1 Emulsion Separation of 10.2 ppg $CaCl_2$ Brine-in-Heavy Crude Oil at 50/50 Ratio

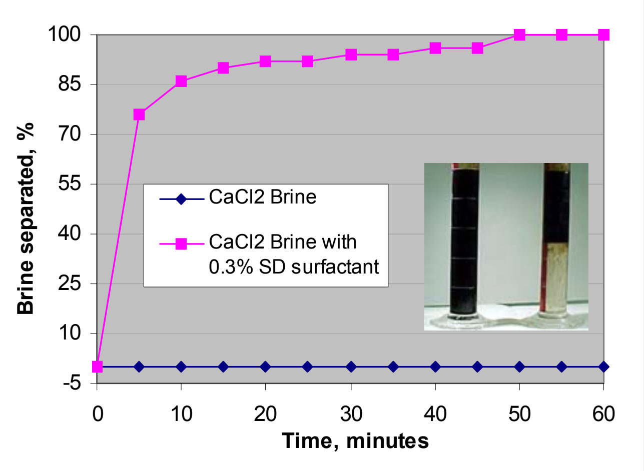

Figure 2 Emulsion Evaluation of 9.5 ppg NaCl Brine-in-Heavy Crude Oil

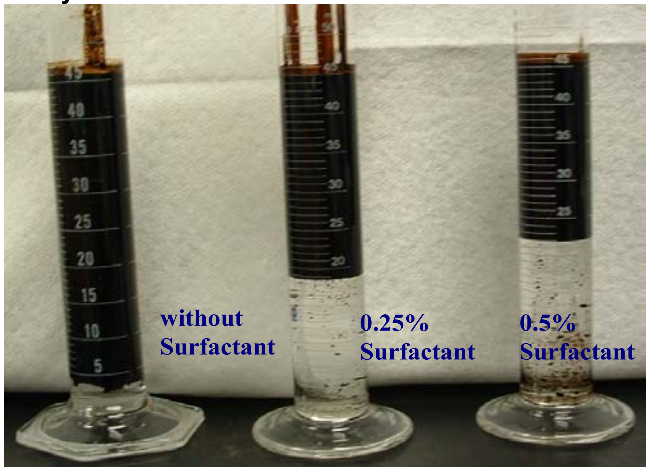

Figure 3: DIF filtrate Evaluated at 50/50 Drill-in/Crude Oil – Field Trial 1

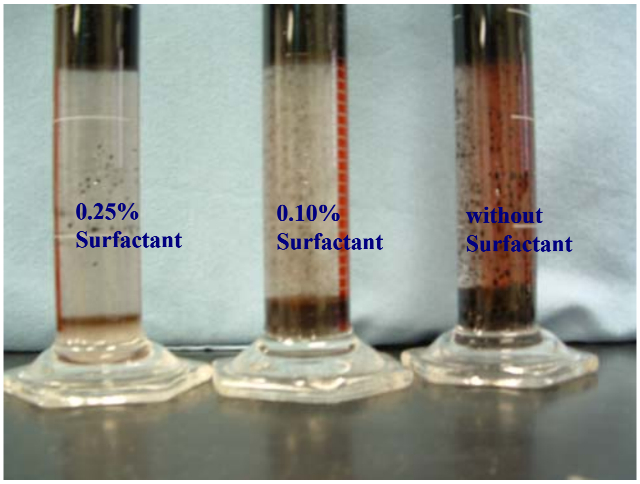

Figure 4 DIF Filtrate with 0.25% SD Surfactant Evaluated with Crude Oil – Field Trial 1

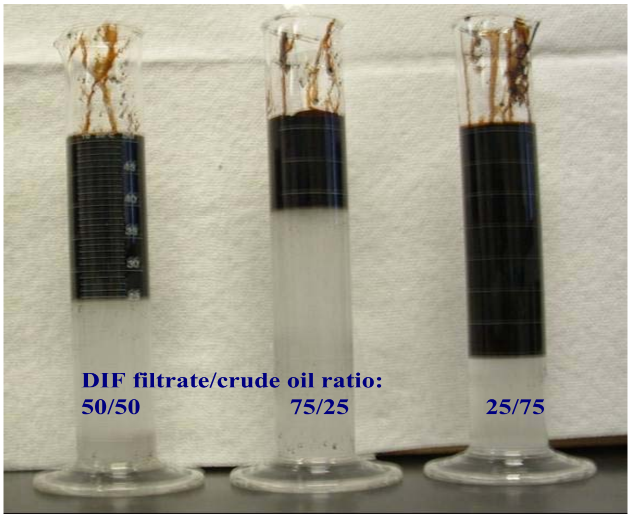

Figure 5 Fluids Separation of DIF with Crude Oil at Various Drill-in/Crude Oil Ratios – Field Trial 1

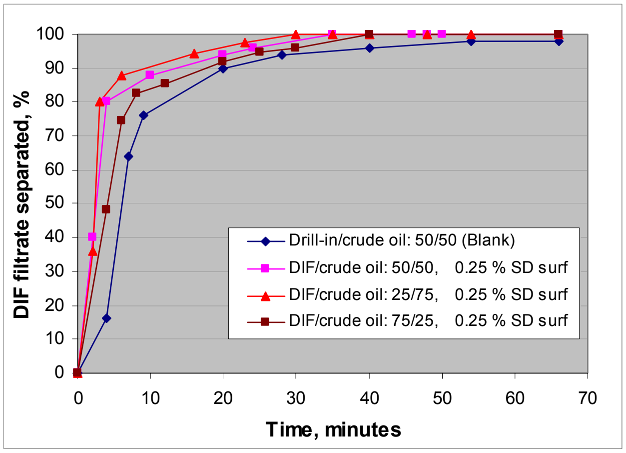

Figure 6 Emulsion Evaluations with 50/50 Brine/Crude Oil - Field Trial 1

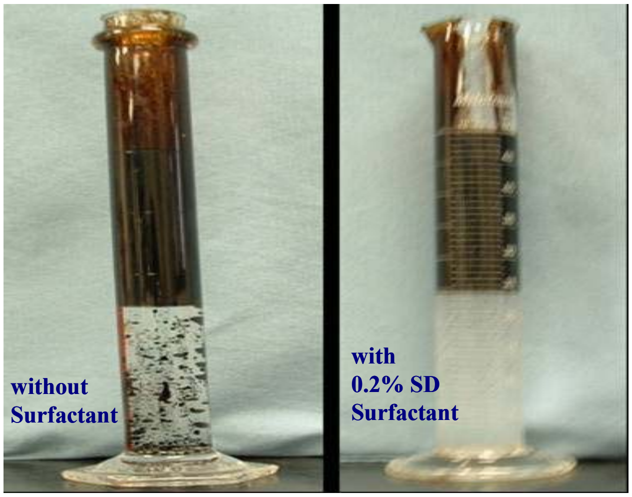

Figure 7 Fluids Separation of Crude Oil from Field Trial 1 and 9 ppg Brine

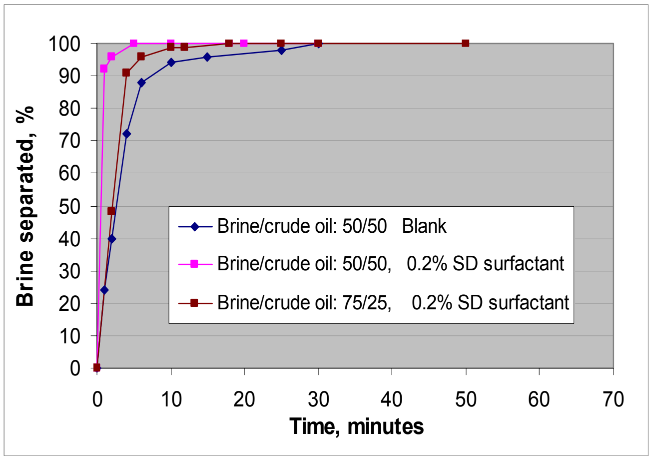

Figure 8 Permeability/Filtration Effect of 0.75% SD Surfactant on OBM Filter Cake

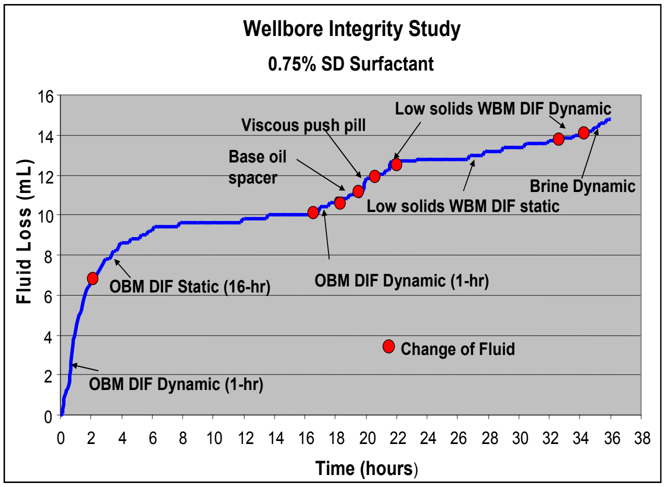

Figure 9 Permeability/Filtration Effect of 1.25% SD Surfactant on OBM Filter Cake