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Return Permeability Optimization Using Flowback Additives in Formate-Based Fluids

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Abstract

Conditions for offshore applications in the GOM are driving the development of heavier fluids for harsh environments. Low equivalent circulating densities (ECDs) are required in order to effectively handle wellbore pressures. Oil-based drill-in fluids are common for this application, but they present several difficulties. Water-based (WB) drill-in fluids using formate brines are a potential solution for the problem.

A high-density WB fluid with minimum solids content to ensure effective bridging and low filtrate invasion into the formation is of interest. The design of formate brine-based fluids is an ideal solution for this problem. For this application, a high density (16.4 lb/gal) drill-in fluid was designed based on cesium-potassium formate brine for 280°F wells with only 75 lb/bbl of calcium carbonates. The application requires a fluid formulation stable from 40°F up to 280°F with flat rheology. The designed fluid was subjected to several tests including HPHT viscometry, HPHT sag test, and return permeability.

The fluid designed with formate brine showed an optimal HPHT viscosity profile, lower ECD values, minimal sag, and good compatibility with shale. The fluid showed tolerance to some contaminants such as seawater and drilling solids, but high spurt/filtrate volume observed would result in reservoir invasion and potentially reduction in relative permeability. A reduction in return permeability of nearly 70% was measured in a return permeability test. Optimization of the fluid design without changing significantly other properties was achieved by adding a flowback additive. A package of reservoir drill-in fluid and the flowback additive ensured very high return permeability values of >90% without significant solids invasion.

Introduction

Low-solids drilling and completion fluids based on cesium/potassium formate brines have been used extensively in the North Sea since the 90's (Saasen et al., 2002; Berg et al., 2007; Jøntvedt et al., 2018). Wells drilled and completed with these fluids have been very productive (Olsvik et al., 2013; Downs and Fleming, 2018). Cesium formate has allowed operators to construct highly productive wells, not only by not damaging the reservoir, but also by enabling the construction of openhole sand-face completion types that cannot be done with solids-laden fluid systems. By using the same formate brine in the drilling, screen-running, perforating, gravel-pack carrying, and upper completion fluids, well construction operations are fast and seamless with the added advantage that the reservoir is only exposed to one fluid filtrate.

Challenging environments in the GOM deep wells at high pressures and high temperatures (HPHT) demand fluids with a low rheological profile, good ECD management, a low coefficient of friction, minimal formation losses, low torque and drag, and non-damaging filtrate and filter cake. Handling high pressures up to 20,000 psi, temperatures up to 250°C (500°F) and narrow pressure windows requires drilling fluids with unique properties. To manage the narrow pressure window in ultra-HPHT wells, low ECD fluids are needed to drill efficiently and safely (Al-Bagoury and Revil 2018).

One of the many advantages of developing drill-in fluids based on high-density formate brines is the low concentration of solids added to the fluid. The addition of weighting materials like barite brings several challenges such as sagging, high rheologies, and solids invasion. Sagging can lead to drilling and completion problems; a density variation or non-linear hydrostatic pressures gradients can lead to pressure control problems, while thick and tight barite beds can lead to high torque and drag, stuck pipes, plugged boreholes and even lost circulation (Skalle et al. 1997).

A performance rating of DIFs is often given after return permeability tests. The best fluids are chosen if relative permeability is not largely affected by the drill-in fluid. The damage caused by the DIF is quantified through oil return permeability measurements and flow-initiation pressures performed to an analogue core at relevant flow rates for oil producer wells (Ding et al. 2002).

Unfortunately, the good productivity from wells drilled and completed with formate fluids is not always reflected in the performance of formate fluids in laboratory return permeability tests. Laboratory test results from flooding core plugs have sometimes been so poor that operators have planned for acid treatment as a contingency. A good example of this is the laboratory tests carried out on core plugs from the Huldra field prior to successfully using cesium formate reservoir drill-in and completion fluid without acid treatment (Saasen 2002). Acid treatment has indeed never been needed after drilling and/or completing wells with cesium/potassium formate brines. The only time an acid treatment was attempted, the untreated well produced at the same rate as the one that was treated, which was 50% higher than expected (Carnegie et al. 2013; Mahadi et al. 2013). In general, wells drilled and/or completed with cesium/potassium formate fluids have all cleaned up successfully, although sometimes it has taken days or weeks to reach maximum flow rates.

The main mechanism put forward for reduced return-permeability values observed in tests with formate-based fluids has consistently been “filtrate retention”, meaning that the residual water content, or water saturation level, of the core has increased during the test which lowers the effective permeability to hydrocarbons, imbibition. With a core’s effective permeability to oil or gas so dependent on the amount of residual formation water and/or brine left in the core at the time of permeability measurement, the result of return permeability testing of formate brines comes down to the efficiency of the selected/imposed drawdown regime in reducing water levels to the initial water saturation level. Although this problem applies to all water-based drilling fluids, the issues are emphasized by the almost solids-free nature of brine-based drilling fluids, like formate fluids.

Productivity losses are especially critical for long horizontal wells which are often completed as an open hole. If damage is produced, it cannot be bypassed by perforations and may lead to large skin factors. High initial spurt loss periods and solids invasion are the main damage caused by WB DIF (Ding et al. 2002).

The problem of filtrate retention in coreflood testing with formate brines has indeed been so severe that formates have mistakenly been disqualified as reservoir drill-in fluids in some prominent HPHT field development projects. An example of this is the first phase of the Martin Linge field development project (Jøntvedt et al. 2018) where an alternative fluid was selected based on coreflood test results indicating a return permeability of only 15% with a cesium/potassium formate drill-in fluid. Only after plugging the screens of three wells with micronized barite, the formate option was revisited. This time, the coreflood testing that was performed in a different laboratory gave acceptable results, despite some fluid retention. The well that was drilled and completed with the cesium/ potassium formate fluid showed very good cleanup performance.

The difference between core plug cleanup and reservoir cleanup is mainly attributed to time, cell configuration, and flow rates. Reservoirs clean up during days and weeks, and the core plug is expected to clean up in minutes. Time doesn’t only allow for biopolymers, such as xanthan gum and starch, that are stabilized by formate brines (Howard et al. 2015), to break down and allow increased flow of filtrate into the wellbore, but also drainage of heavy formate filtrate away from the wellbore by gravity. Equinor (Fleming et al., 2015) concludes in a formation damage study done for the Valemon field that “It should be noted that formate filtrate retention was an issue in lower permeability plugs, although it is believed that much of this liquid would be removed from the near wellbore with continued production.” Equinor petrophysicists also made an interesting observation when drilling and completing the Kristin and Kvitebjørn wells (Pedersen et al., 2006). When they compared the LWD logs acquired three days after drilling with the wireline logs acquired about 6-7 days after drilling, it was evident that wireline density was less affected by the cesium/potassium formate filtrate than the LWD density. This was explained by the fact that the filtrate invaded very fast during drilling but was displaced with gas by gravity segregation during the time of wireline logging.

Filtrate imbibition could be improved by decreasing the capillary pressure, thus enhancing the relative permeability values. Microemulsions have been added to drill-in fluids as flowback enhancers to expedite the filtrate return and maximize the wellbore relative permeability. The unique mixture of solvents and surfactants in the microemulsion is used to alter capillary pressure and wetting profiles, diminish water blocks, improve hydrocarbon mobility, allow the multi-flow, and increase effective permeability (Swanson et al. 2018). The flowback enhancer must be compatible with the fluid base brine to avoid adverse effects.

Knapik et al. 2021 stressed the advantages of using flowback fluids/additives while preparing drill-in fluids. The additives have a positive impact on the DIF’s properties. The flowback additives could increase viscosity, reduce filtrate, inhibit better clays, and control hydrostatic pressures due to the positive action or synergistic effect between the flowback additives and other chemicals in the fluid.

This paper presents the design of a cesium/potassium formate drill-in fluid for use in an HPHT oil reservoir in the Gulf of Mexico with special emphasis on the flowback additive, which significantly increased the return permeability measured in the laboratory return permeability test.

Fluids Formulations and Properties

The base brines used to develop the fluids must have a pressure crystallization temperature (PCT) lower than 29°F at 16,810 psi per operations constrains. The standard API 13J method for measuring true crystallization temperature (TCT) in heavy brines is not suited for measuring TCT in formate brines due to extreme supercooling and the existence of metastable potassium formate crystals. A method that requires seeding with crystals of the dominant formate salt was used for both TCT and PCT measurements. This method will be included in the 6th edition of API 13J. PCT was measured at 9,000 and 18,000 psi. **Figure 1** shows measured PCT as function of pressure. As can be seen from the figure, the estimated PCT at 16,810 psi is significantly lower than the required 29°F. The brine exhibited a TCT of 7°F at 15 psi.

Table 1 shows the water-based drill-in fluid (WB DIF) formulations without flowback additive (WB DIF 1) and with flowback additive (WB DIF 2).

The fluids were designed for a final density of 16.4 lb/gal. The target density downhole was 16.5 lb/gal. the final density of the fluid was decreased 0.1 lb/gal to accommodate for compressibility.

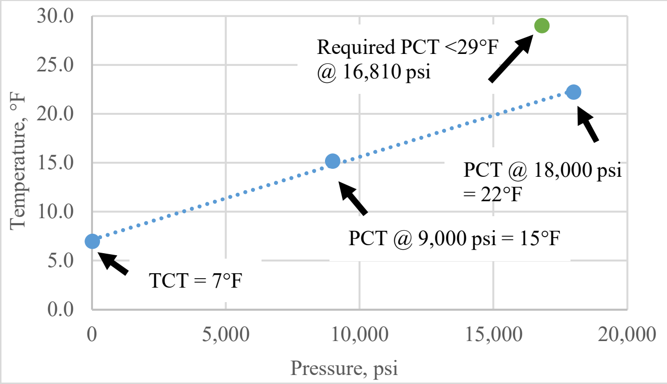

Figure 1 – Measured TCT and PCT versus pressure for the 16.5 lb/gal Cs/K formate brine.

Table 1- WB DIF Formulations.

Products	WB DIF 1, lb/bbl	WB DIF 2, lb/bbl
16.51 lb/gal Cs/K Formate	299	299
Water	19	19
Fluid Loss Polymer	6	6
Xanthan Gum	0.5	0.5
Oxygen Scavenger	1	1
Calcium Carbonate Package	75	75
Flowback additive	-	1

The added flowback additive is a proprietary microemulsion designed for fluids with extreme salt concentrations or close to saturation. The microemulsion is capable of changing the contact angle and allow multi-flow in the near wellbore region (Swanson et al. 2018).

Table 2 and **Table 3** summarizes the rheological properties of the WB drill-in fluids without and with flowback additive. Properties did not change tremendously when flowback additive is added, but the rheology is slightly higher. The microemulsion additive has the advantage of enhancing all the products in the fluid (Knapik at al. 2021). The hydration of polymer is more efficient when the flowback additive is added. A small further modification of the fluid could be done by slightly reducing xanthan gum concentration.

The fluids exhibit low 600 RPM readings giving an indication of possible low ECD. The fluids also exhibit flat rheology as can be seen in the 6 RPM reading, yield point (YP) calculation, and gels.

Table 2 – Rheological properties for WB DIF 1.

	Before Hot Rolling	After Hot Rolling				
Rheology Temp, °F	120	40	80	100	120	150
600 RPM	84	244	127	93	82	69
300 RPM	54	149	79	60	53	44
100 RPM	28	70	39	30	28	23
6 RPM	6	13	9	7	7	6
3 RPM	5	10	6	5	5	4
PV, cP	30	95	48	33	29	25
YP, lb/100 ft^2	24	54	31	27	24	19
10 s gel, lb/100 ft^2	4	9	6	4	4	4
10 min gel, lb/100 ft^2	18	10	6	5	5	4
30 min gel, lb/100 ft^2	-	11	7	5	5	4

Table 3 – Rheological properties for WB DIF 2.

	Before Hot Rolling	After Hot Rolling				
Rheology Temp, °F	120	40	80	100	120	150
600 RPM	82	239	149	119	99	79
300 RPM	52	148	95	76	63	52
100 RPM	26	74	49	40	34	29
6 RPM	5	18	13	12	10	9
3 RPM	4	14	11	10	8	7
PV, cP	30	91	54	43	36	27
YP, lb/100 ft^2	22	57	41	33	27	25
10 s gel, lb/100 ft^2	3	14	9	8	8	6
10 min gel, lb/100 ft^2	10	15	11	9	9	7
30 min gel, lb/100 ft^2	-	18	13	10	9	7

HPHT rheology was also measured for the WB DIF 1 and WB DIF 2. **Figure 2** shows the trends for the 6 RPM reading, the YP and the gels at different temperatures from 40°F up to 280°F and pressures from 15 psi up to 27,000 psi of WB DIF 1. Similar trends were obtained with WB DIF 2. At lower temperatures, the fluid rheology slightly increased; however, at higher temperatures and pressures the rheology became stable and flat. Gels do not change significantly when comparing the values at 40°F and 120°F at different pressures. The profile is a typical profile for flat rheology water-based drill-in fluid.

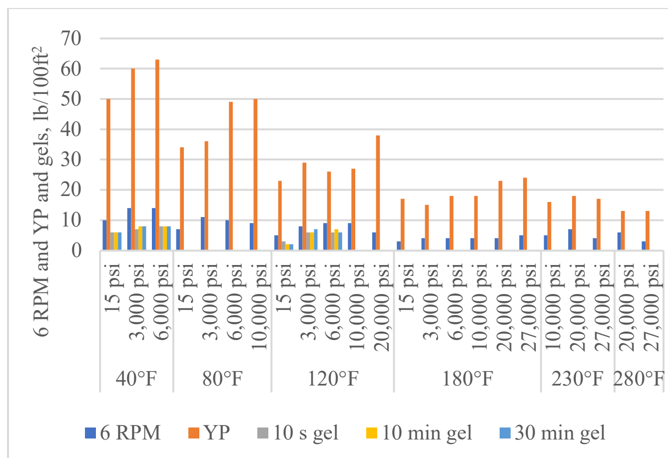

Figure 2 – WB DIF 1: HPHT rheology profile.

Through conducting hydraulic modeling with an array of variables the fluid demonstrates its ability to deliver low ECD's in complex deep-water designs. Standard modeling of complex wells required the use of HPHT viscosity measurements and density corrections, which is normally reserved for non-aqueous fluids to improve the predictive analysis.

Hydraulic simulation was conducted using annulus and drill string geometry as well as equivalent down hole density of 16.5 lb/gal as fixed parameters. The variable parameters included flow rates of 260 gal/min up to 450 gal/min, ROP from 25 ft/h to 125 ft/h and pipe rotation from 130 RPM up to 150 RPM. All simulations were performed to show measurements at the casing shoe and TD, which are the weak points during.

The ability of the fluid to deliver low ECD's as seen in **Figure 3Error! Reference source not found.** and **Figure 4** is due to the low solids content of the fluid and the low viscosity measurements made at wellbore temperature and pressure (see Figure 2). The figures show simulations performed for WB DIF 1 using 130 RPM of pipe rotation and 50 ft/h and 100 ft/h of ROP.

Conducting modeling once the casing shoe is drilled (Figure 3) and comparing the results obtained at TD (Figure 4) shows an increase of 0.05 lb/gal while drilling the interval. Fluid density while drilling casing shoe and TD never reached the fracture density of 17 lb/gal.

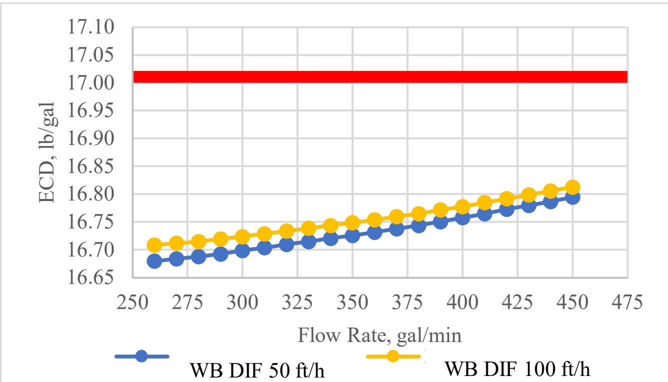

Figure 3 – WB DIF 1: ECD study at drilling casing shoe at 130 RPM with ROP at 50 ft/h and 100 ft/h.

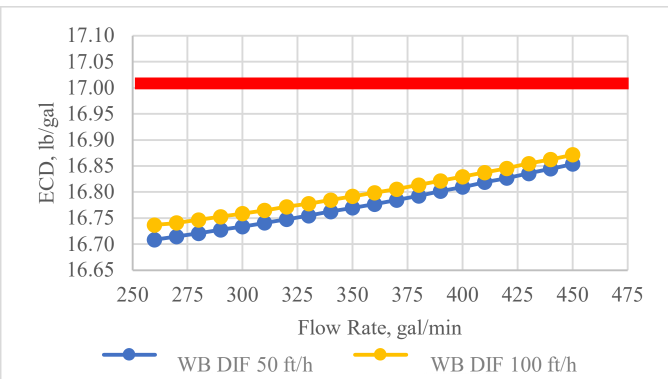

Figure 4 – WB DIF 1: ECD study at total depth and 130 RPM with ROP at 50 ft/h and 100 ft/h.

The pH of the filtrate was determined following the API 13J recommended practice. Filtrate from API filtration test had a pH of 9.05 at 25°F. The followed test procedure to determine pH of a formate brine is described in the API 13-J recommended practice, where the filtrated is diluted with DI water on a ratio of 1 to 9.

No significant differences were observed between the ability of WB DIF 1 and WB DIF 2 to control fluid loss. **Table 4** summarizes the fluid loss volume and the filter cake thickness obtained after filtration tests. Several techniques were used to determine the fluid loss: 1) API filtrate as described in API 13B-1 at room temperature and 100 psi for 30 min, 2) HPHT filtrate on paper as described in API 13B-1 at 280°F and 500 psi differential pressure, and 3) HPHT filtrate on ceramic disc as described in API 13B-1 at 280°F and 500 psi differential pressure with 12 µm and 20 µm.

Table 4 – WB DIF 1: Fluid loss tests.

Fluid loss	Value	
API Filtrate	1.2 mL	
API Filter Cake Thickness	1/32 in	
HTHP Filtrate @ 280°F	8.0 mL	
HTHP Filter Cake Thickness	1/32 in	
HTHP Filtrate @ 280°F on disk, actual mL	12 µm	20 µm
1 min	2.0	1.6
30 min	7.0	6.8
1 h	9.2	9.0
2 h	12.5	13.0
3 h	15.0	15.5
4 h	16.5	17.0
HTHP Filter Cake Thickness, in.	2/32	2/32

A particle plugging tester was used to determine the fluid loss in a ceramic disc of 12 µm and 20 µm after 30 minutes at 280°F and 1,000 psi differential pressure. **Figure 5** shows the actual volume in milliliters against the square root of time. The spurt loss was lower than 9.0 mL for both tests.

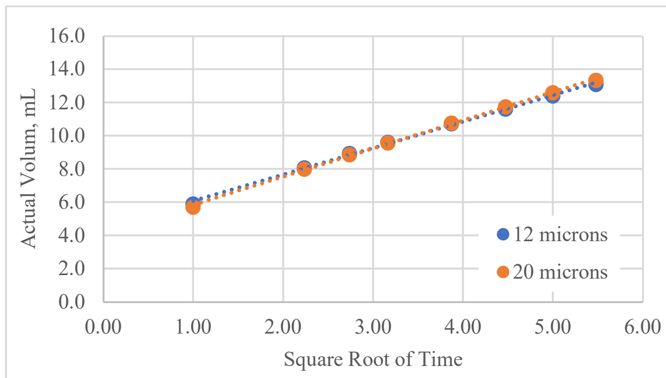

Figure 5 – WB DIF 1: PPT fluid loss test at 280°F on ceramic discs.

Determination of sagging of the fluid at 15 psi and high pressure is crucial for the fluid selection when drilling deep deviated wells. The requirement for this fluid was less than 0.5 lb/gal delta between the bottom density and the top density of the fluid after static aging.

The DIF was added to an aging cell, pressurized up to 100 psi, and placed in an oven at 280°F for a given period of time. After the time elapsed, the cell was opened and the separated brine was removed and measured. The fluid was then separated in three aliquots, being careful of not disturbing the layers. The density for each layer was then measured.

For the HTHP sag tests, a Grace Model M8500 HPHT Sag Tester was used. The fluid was added to the cell, pressurized at 20,000 psi and temperature raised up to 280°F. The test was performed for 14 days. After the time elapsed, the cell was opened and the separated brine was removed, and the density measured. The fluid was then separated in three aliquots, being careful of not disturbing the layers. The density for each layer was then measured.

Figure 6 shows the results for the 100 and 20,000 psi test at 280°F for 3 days and 14 days. The delta density and the separation of brine increased over time. However, when pressure was added to the fluid, the delta density decreased. Sag test at higher pressures is a test that represents the possible outcome when the fluid is left static in the reservoir.

Percentage separation of the brine at higher pressures was higher (45%) compared to the lower pressure results (36%). However, the based-brine fluid density is so close to the final fluid density that differential density after separation was not detrimental for the fluid. The fluid can easily be reconstituted after applying shear.

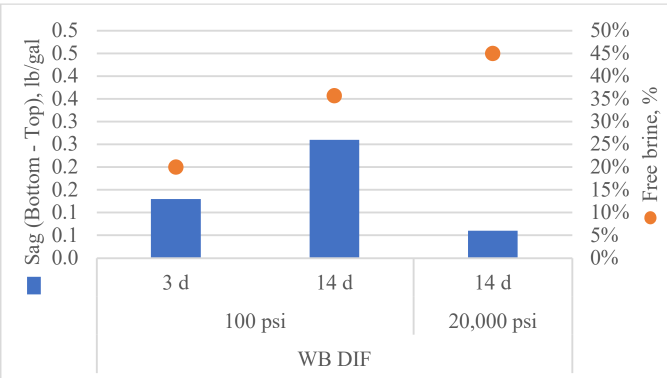

Figure 6 – WB DIF 1: Sagging test at 100 psi and 20,000 psi and 280°F.

WB DIF was contaminated with drilling solids (20 lb/bbl) and seawater (20 vol%). The rheology decreased slightly with the seawater addition (dilution) and fluid loss almost doubled in the API filtration tests. When fluid was contaminated with drilling solids, the rheology slightly increased yet maintaining the flat profile.

A suitable clay sample from the GOM was used to determine the interaction of the WB fluid with reactive shale. The tested shale sample contained 16 wt% mixed layer, 5 wt% illite clay, 3 wt% chlorite clay, and 6 wt% kaolinite clay.

The reactive shale was exposed to the WB DIF 1 and evaluated using linear swell meter (LSM), shale-particle disintegration, and bulk hardness tests.

Figure 7 shows the LSM test results. The test was conducted using a FANN Linear Swell Meter 2100 under static conditions following the instructions from the manufacturer (FANN, 2018). Wafers were prepared using a FANN Compactor.

The shale wafer was exposed to different fluids at room temperature for 48 hours. Swelling was significantly less when the shale was exposed to WB DIF compared to fresh water and synthetic formation water.

Shale-particle disintegration test was performed following the API-13I recommended practice. The shale recovered when exposed to fresh water was only 16%, while when exposed to synthetic formation water it increased to 55%. Yet, when shale was exposed to the WB DIF 1, the percentage recovery increased to 95%.

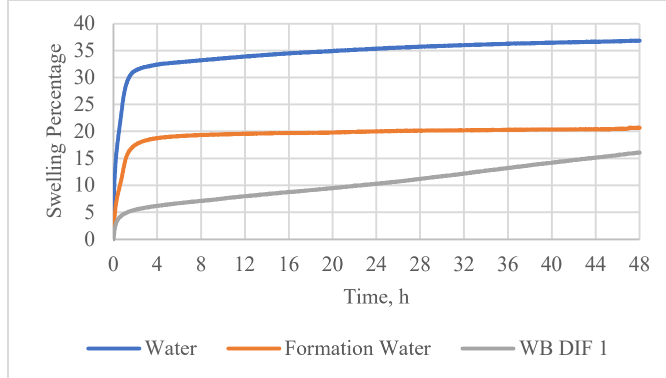

Figure 7 – LSM tests: wafer exposed to water, formation water, and WB DIF 1 at room temperature.

Bulk hardness test was performed using a bulk hardness tester from OFITE. Instructions provided by manufacturer were used to perform the test (OFITE, 2016).

Shale was exposed to WB DIF 1 and hot-rolled overnight at desired temperature and 100 psi. The shale was then collected using a 30-mesh sieve and added to the extrusion cup. The piston was rotated using a torque wrench and the maximum deflection during each revolution was recorded. Rotations continued until the torque was grater or equal to 100 in-lb. The number rotations needed to reach the maximum torque was recorded.

Fresh water took only one rotation to generate 100 in-lb and the wafer is shown in **Figure 8**a, while synthetic formation water needed four rotations to reach 100 in-lb (Figure 8b); WB DIF 1 needed 13 rotations to generate the maximum torque (Figure 8c). Wafers are considerably taller when the shale is not affected by the fluid due to the higher recovery capacity and minimum interaction with tested fluid.

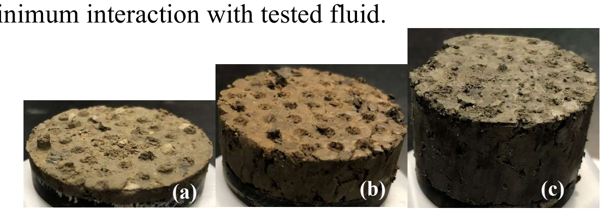

Figure 8 – Bulk hardness test: shale wafer after tests and exposed to (a) fresh water, (b) formation water, and (c) WB DIF1.

Return-to-Flow at Constant Flow:

The return-to-flow is a preliminary test performed with the drill-in fluid as a reliable and low-cost screening test. This test does not provide return permeability data. The best result is then evaluated in a permeameter using an analogue core for return permeability quantification.

The test is conducted using constant flow rates in a return-to-flow tester. For this specific case, 12 µm ceramic discs with 2.5 in od diameter and 2.5 in thickness were used. The discs were soaked in synthetic formation water prior to testing. The initial differential pressure was then measured on the pre-saturated disc by flowing mineral oil in the production direction until stabilization; three different flow rates were evaluated including 4, 8, and 16 mL/min. Then, mud-off was conducted for 4 hours at 280°F with 500 psi differential pressure.

After mud-off, final production was tested by measuring differential pressures at the same flow rates.

Figure 9 shows the return-to-flow test results for the WB DIF 1 and WB DIF 2 at 4 mL/min. The higher the flow rate, the higher the return-to-flow values. WB DIF 1 showed return-to-flow values from 58% up to 79%, depending on flow rates. WB DIF 2 showed return-to-flow values from 82% up to 96%., indicating that the addition of the flowback additives to the WB DIF can enhance the relative return permeability. Results must be corroborated using analog cores in a permeameter.

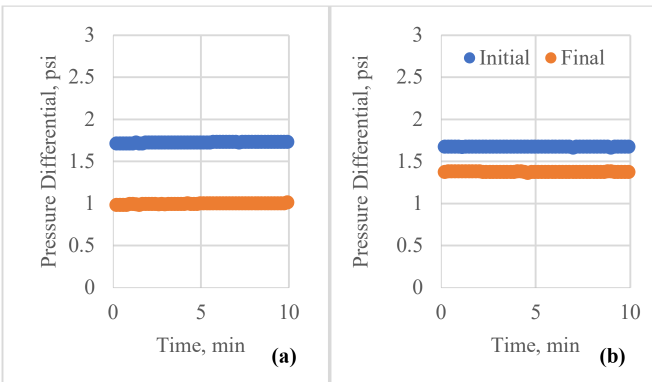

Figure 9 – Return-to-flow test at 280°F and 4 mL/min on a 12 µm disc with (a) WB DIF 1 and (b) WB DIF 2.

Return Permeability Test

Castlegate sandstone was the selected analogue core plug used for the testing. Core samples are from the late cretaceous formation. The cores had a relative permeability to air of 1,200 mD with a porosity between 27 and 29%. Synthetic formation brine and LVT-200 were used as formation water and permeating fluid respectively for the return permeability tests.

All core plug samples were evacuated of air and pressure-saturated with synthetic formation brine. The core was loaded into an air displacing brine centrifuge configuration and spun to initial water saturation at 200 psi capillary pressure for a period of 4.0 hours. Then, the core was unloaded from the centrifuge and briefly vacuum saturated with the permeating oil phase.

1,500 psi net confining stress was applied, and 300 psi pore pressure was established using the permeating oil through the system and sample, then temperature was elevated to 280°F.

Permeating oil was produced at a constant rate for approximately 10 pore volumes while monitoring differential pressure. Effective permeability to oil at initial water saturation was determined at three rates: 4.0, 6.0, and 10.0 mL/min.

The drill-in fluid sample was then circulated across the face of the core at an overbalance pressure of 850 psi and a flow rate of 10.0 mL/min for a period of 10 minutes. The flow rate was reduced to 4.0 mL/minute for 50 minutes, and then reduced to 2.0 mL/min for 3 hours. Leakoff was monitored and volumes recorded. The drill-in fluid was set at 850 psi overbalance and left for overnight static soaking (12 hours).

Permeating fluid was circulated across the inlet face of the sample at a rate of 30.0 mL/min for 30 minutes to potentially remove excess drill-in fluid.

Next, permeating fluid was injected from the reservoir side of the core in the production flow direction at a low flow rate of 0.25 mL/min to determine the liftoff pressure of the filter cake.

Permeating fluid was injected through the core plug at a constant flow rate of 2.0 mL/min in the production direction to determine when flow has reached an equilibrium. Regain effective permeability to oil at residual fluid saturation was then determined at three rates: 4.0, 6.0, and 10.0 mL/min.

Figure 10 shows results of the return permeability tests with WB DIF 1. The filter cake liftoff pressure was 1.2 psi. Return permeability after producing permeating fluid was only 29%. The filtrate could have altered the near-well flow properties, which could dramatically reduce production (Ding et al. 2006).

In order to establish possible causes of the reduced relative permeability, the core sample was taken from the permeameter and centrifuged at the same gas-displacing-brine pressure as was used to establish irreducible water saturation (200 psi air-displacing-liquid).

Coreholder, sample, and system were elevated to previous pressure conditions (net confining and pore pressure).

Permeating oil was injected through the core plug at a constant rate in the production direction while monitoring differential pressure. Regain permeability increased to 64%. Therefore, some of the poor performance could be associated with filtrate retention in the near-wellbore region.

When the core was centrifuged, most of the filtrate was easily displaced. Therefore, emulsification was unlikely to have been the cause of the problem. WB DIF 1 filtrate invaded the core plug and created a two-phase flow process, imbibition. The filtrate could generate a high wetting phase saturation in the invaded zone (Ding et al. 2002).

At the tested flow rates, the filtrate could not be moved efficiently. However, if flow rates are increased, filtrate could be produced and the relative return permeability increased.

The test was designed to show the worst-case scenario. In further testing with other fluids, the production rates were increased up to 50 mL/min to simulate production rates in the wells. Yet, tests at higher production rates were not performed with this fluid.

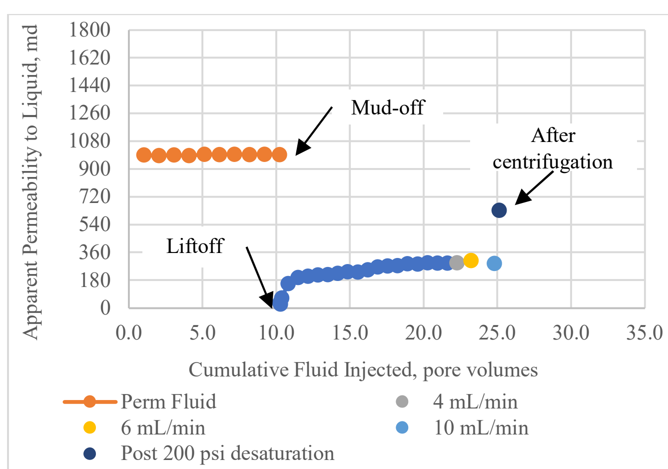

Figure 10 – WB DIF 1: Return permeability test at 280°F.

Scanning electron microscope (SEM) was used to determine if the solids were also invading the formation. The core, from the return permeability test with WB DIF 1, was dried and trimmed. **Figure 11**, **Figure 12**, and **Figure 13** show the clean core face, core face with deposited drill-in fluid, and solids invasion depth, respectively. According to the images, the drill-in fluid invaded less than 100 microns. Therefore, the theory of filtrated retention was reinforced due to the low solids invasion.

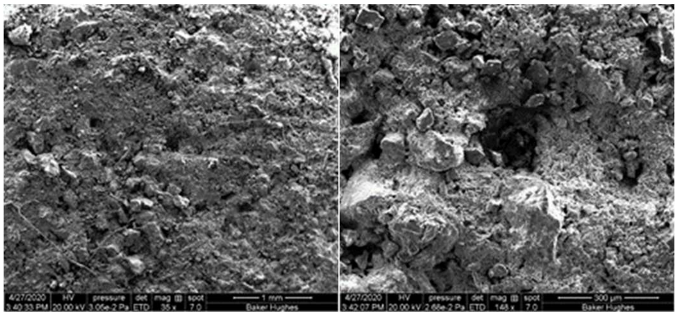

Figure 11 – WB DIF 1: SEM images for the clean face of the core at 35x and 148x magnification.

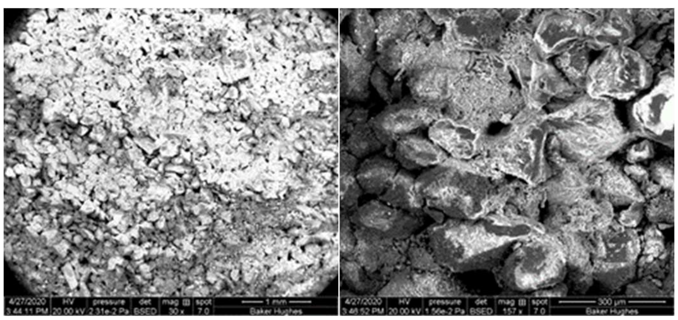

Figure 12 – WB DIF 1: SEM images for the core face with WB DIF at 30x and 157x magnification.

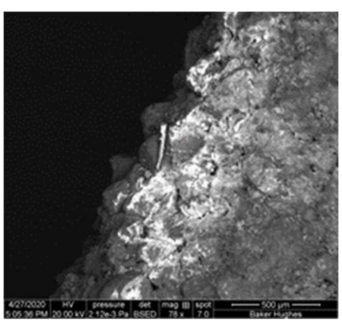

Figure 13 – WB DIF 1: SEM images for the WB DIF invasion at 78x magnification.

The drill-in fluid was fine-tunned and 1.0 lb/bbl of flowback additive was added. An engineered microemulsion was used as a flowback enhancer. The especial additive is capable to resist extreme high salinities and high temperatures without precipitating out of the system.

The surface tension of the fluids was determined using a Krüss K100 at room temperature. The formate-base brine had a surface tension of 93 mN/m. When 1.0 lb/bbl of flowback enhancer is added to the base brine, the surface tension decreases to 29 mN/m. Turbidity was determined using a AQUAfast turbidity meter from Thermo Scientific. The turbidity of the formate brine was 3.3 NTU. After adding the flowback additive, turbidity increased to 106.0 NTU.

The treated fluid was also tested for return permeability. **Figure 14** shows the test results using WB DIF 2. Liftoff pressure for the filter cake was 1.2 psi. The return permeability after producing permeating fluid was 21%. But after centrifugation, the return permeability increased to 93%. The filtrate fluid was easily displaced from the near-wellbore.

Capillary pressure cannot be measured directly in a reservoir. Only the capillary forces explain why water is retained in the formation. It is related to surface or interfacial tension, contact angle, and pore radius within the formation (Franchi 2002). Lowering the surface tension and /or modifying the contact angle between the filtrate and the rock affect the capillary pressure and fluid flow.

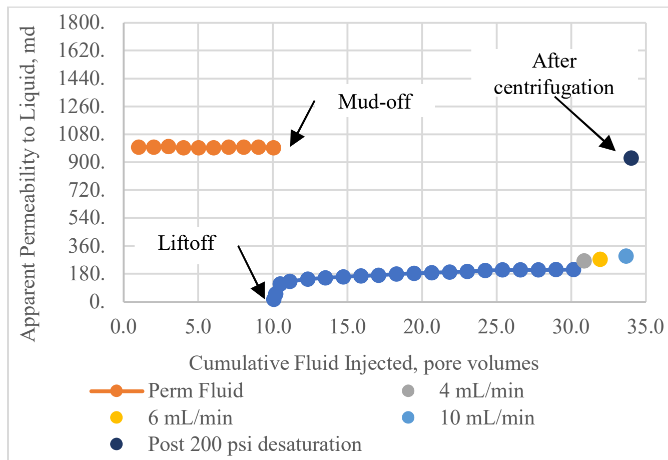

Figure 14 – WB DIF 2: Return permeability test at 280°F.

After return permeability tests with WB DIF 2, the tested core was dried, trimmed, and analyzed. SEM was used to identify solids invasion at the wellbore end of the core plug. **Figure 15**, **Figure 16**, and **Figure 17** show the clean core face, core face with deposited drill-in fluid, and solids invasion depth, respectively. According to the images, the drill-in fluid invaded less than 100 microns, and the invasion was not uniform. Solids were probably removed when flowing permeating fluid through the core.

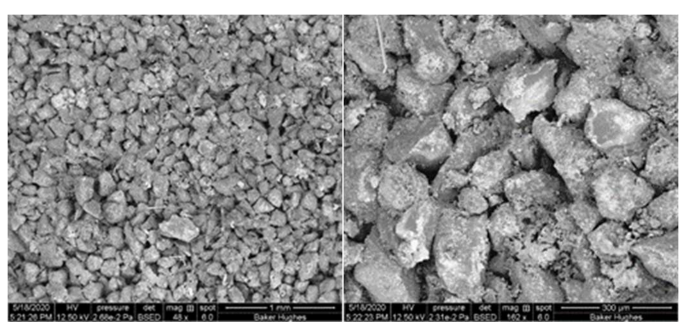

Figure 15 – WB DIF 2: SEM images for the clean face of the core at 48x and 162x magnification.

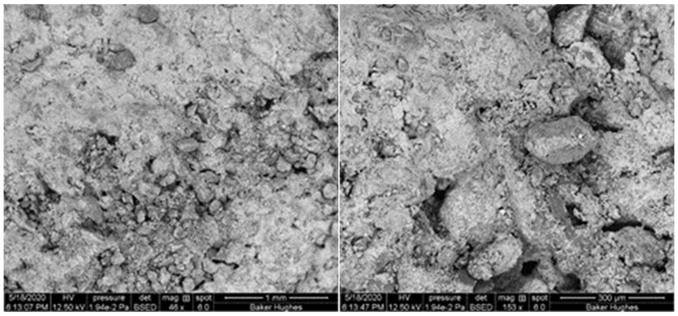

Figure 16 – WB DIF 2: SEM images for the core face with WB DIF at 46x and 153x magnification.

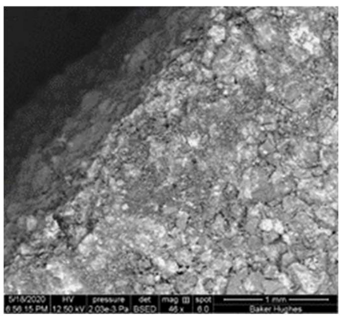

Figure 17 – WB DIF 2: SEM images for the WB DIF Invasion at 46x magnification.

Conclusions

- An optimized, low ECD, high density water-based drill-in fluid was designed for 280°F wells using cesium/potassium formate brine and the addition of a flowback additive.
- Additional benefits of the developed fluid include flat rheology, clay control, tolerance to seawater and drilling solids contamination, and low sagging.
- The centrifugation step after return permeability test confirmed reduced return permeability due to filtrate retention.
- Return permeability of the WB DIF was enhanced with the addition of an engineered flowback additive. The engineered additive was able to resist the high salinity of the formate-based brine used to develop the DIF.
- Return permeability was enhanced from 64% up to 93% after centrifugation and minimal solids invasion was observed despite the inherent high fluid loss.
- The flowback additive generated positive changes in the properties of the base brine fluid, such as surface tension reduction, which resulted in reduced capillary pressures and increased mobility of the filtrate from the analogue core.
- The flowback additive helps with the multi-flow capacity of fluids in the analogue core, enhances fluids properties, increases relative permeability to hydrocarbons, and reduces imbibition caused at the near-wellbore region when filtrate invasion occurs.

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Nomenclature

API	*= American petroleum institute*
Cs/K	*= Cesium/Potassium*
DI	*= Deionized*
DIF	*= Drill-in fluid*
ECD	*= Equivalent circulation density*
GOM	*= Gulf of Mexico*
HPHT	*= High pressure high temperature*
LSM	*= Linear swell meter*
PCT	*= Pressure Crystallization Temperature*
PV	*= Plastic viscosity*
ROP	*= Rate of Penetration*
SEM	*= Scanning electronic microscope*
TCT	*= True Crystallization Temperature*
TD	*= True Depth*
Temp	*= Temperature*
WB	*= Water-based*
YP	*= Yield point*

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