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A New Direct Emulsion Drilling Fluid: Design, Delivery, and Lessons Learned

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Abstract

Direct emulsion drilling fluids find occasional use in depleted reservoirs and other specialty applications, but a new application shows broad potential for numerous wells in the Permian Basin. A new direct emulsion system was recently engineered for precise density control to avoid losses and eliminate a casing string by combining a troublesome salt zone and a low fracture gradient zone in the intermediate section. Formulating a direct emulsion system, utilizing a saturated sodium chloride continuous phase made from field brine, presented unique challenges.

Originally, direct emulsions were used to address stuck pipe and lubricity[1]. Other applications noted some benefits with mixed overall results[2]. In the past 25 years, direct emulsion designs focused on depleted reservoirs where the desired mud weight is below water[3,4]. The new system design focuses on inhibiting a salt formation to minimize washout, hence the requirement for the saturated sodium chloride brine phase. With less free water, other types of stabilizing surfactants are necessary to avoid separation of the oil from the direct emulsion. Through extensive laboratory testing, a formulation was qualified for field use to tolerate expected drilling challenges.

Deployment of the system revealed new issues and testing required for quality control and effective fluid property management. The first two wells faced significant drilling challenges while the system remained stable in the presence of water flows, providing assurance of system stability in the field. Subsequent applications encountered conventional circumstances, demonstrating the efficiency of the system.

Introduction

This paper begins by reviewing the design requirements for the direct emulsion system. A general overview of emulsions highlights the distinctions of a direct emulsion system. From this general understanding, the laboratory evaluation process is reviewed as well as field trial preparation leading up to the initial delivery of the direct emulsion system. The paper concludes with results of the field trial and conclusions of the design process.

Design Scope

The objectives for the direct emulsion fluid were to provide a stable direct emulsion drilling fluid for use in the intermediate sections of Permian Basin wells that contain shallower salt zones and deeper lost circulation prone sections. The system needed to be designed to minimize salt washout by maintaining a near saturated external sodium chloride brine phase. It also needed to be able to incorporate oil (diesel) to allow the mud weight to be adjusted to eliminate lost circulation in low fracture gradient deeper zones. The system needed to provide good hole cleaning, moderate temperature stability (< 250°F), weighted up for well control situations, low coefficient of friction, corrosion control and able to tolerate various contaminants (green cement, acid gases, salt and solids). For additional cost savings, it needed to assist in providing a good rate of penetration and could be re-used, well to well.

Emulsion Overview

An emulsion is simply a mixture of two immiscible liquids. The two liquids may be blended by mixing energy, but without a stabilizing component, rapidly separate. In most oilfield applications, an emulsifying surfactant provides this stability. Other emulsifying agents include lignites, lignosulfonates, starches, and solids[1]. These additives may be combined to enhance stability or alter other fluid properties.

An invert emulsion features an oil-continuous phase with a dispersed aqueous non-continuous phase. A direct emulsion features a water-continuous phase with a dispersed oil non-continuous phase **(Image 1)**.

Image 1: No emulsion (left), 70:30 oil:water ratio invert emulsion (center), and 30:70 oil:water ratio direct emulsion (right)

Surfactants

An emulsifying surfactant reduces the surface tension between the oil and water phases. Surfactants feature a hydrophobic tail and a hydrophilic head **(Figure 1)**. The affinity for oil and water varies by surfactant, and selecting an appropriate chemistry is critical to stability for a given application.

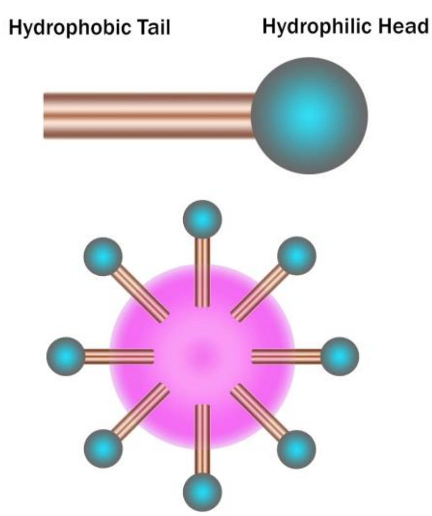

Figure 1: Direct emulsion featuring oil droplet with surfactant alignment

Stability is further complicated by a saturated brine phase, which can disrupt the emulsion as surfactant solubility is limited by less available free water. There are a number of incidents where drilling through salt layers destabilized an invert emulsion as the internal brine phase became saturated with formation salt.

Invert Emulsions

Invert emulsions offer a number of performance advantages, including lower fluid loss, superior shale inhibition, and higher lubricity relative to water-continuous systems.

However, at a higher cost and with the risk of lost circulation, as well as a potentially lower rate of penetration, the invert emulsion was unattractive for this particular application.

Direct Emulsions

The dispersion of the lighter oil phase lowers the overall density of the direct emulsion. However, due to the brine-continuous phase, the direct emulsion is water wet and acts like a water-based drilling fluid, thus allowing water-based products to be used.

Some benefits associated with this direct emulsion are its saturated sodium chloride external phase, improved lubricity and low solids, thus resulting in reduced salt zone washout and higher rates of penetration as compared to clay-based drilling fluids.

Laboratory Evaluation

Identifying appropriate products and optimizing concentrations required a thorough lab evaluation. Beyond the base formulation, the direct emulsion system requires sufficient flexibility to tolerate a variety of contaminants and address operational concerns.

As with invert emulsions prepared in a laboratory environment, it was expected that a lab-prepared direct emulsion would exhibit lower stability than one sheared through a drill bit and laden with drill solids. With that understanding, it was believed that laboratory formulations offered a worst-case scenario for stability evaluation.

Base Formulation

The history of direct emulsion systems provided a clear starting point for this application, specifically identifying a compatible surfactant to stabilize the system and prevent phase separation in saturated sodium chloride brine.

The first step in the screening process for a viable surfactant involved mixing 30:70 oil:bine ratio fluids using diesel as the oil, field brine and a viscosifier. Surfactants were added at varied concentrations and each mixture was static aged for 16 hours at 150°F. Samples showing minimal separation continued to the next phase.

In the second phase, drill solids were added to the formulations. Static aging was repeated and the formulations that showed the least phase separation were further tested. It was noted that phase separation fell into two categories. The first demonstrated a milky but partially emulsified oil phase separation from the brine phase. The second category showed complete phase separation of the oil from the base fluid as seen at the top of the sample **(Image 2)**.

Image 2: Successful sample (left), emulsified phase separation (center), and top-oil separation (right)

The final steps in the testing of the base formulation included stability testing with corrosion inhibitor and hydrogen sulfide scavenger. The saline environment offered additional risk of corrosion and the exposure to hydrogen sulfide were known drilling risks. These additives did not result in any emulsion instability. With an established base formulation, the system was tested for tolerance to relevant drilling issues and contaminants.

Stress and Contingency Testing

The stress testing matrix included many potential contaminants as well as contingencies. In each case the base formulation was mixed with the contaminant and aged in a static oven. Rheology and fluid loss were measured, along with other relevant properties.

Cement contamination was unlikely due to the pre-setting of most surface casing. However, the potential to introduce elevated calcium and pH were a concern for stability. Four (4) lbm/bbl of cement was mixed and had no impact on rheology and fluid loss.

Dry sodium chloride (salt) was added to observe any adverse interaction with the surfactant. No appreciable change in properties occurred. Fifty (50) lbm/bbl of simulated drill solids were added and did not alter the emulsion stability and other changes in fluid properties were as expected. Carbon dioxide contamination did result in some foaming.

In addition, testing included elevating the pH to 11, which would be required (at least a pH > 10) if hydrogen sulfide gas was expected or encountered. For well control, water flows or weighted mud caps, the system was weighted up to twelve (12) lbm/gal with barite. The twelve (12) lbm/gal sample was static aged for five days at 150°F **(Image 3)** and demonstrated minimal phase separation.

Image 3: 12 lbm/gal sample after 5 day static age

Procedures for Field Testing

Stress testing revealed some potential for phase separation. In an effort to test for signs of decreasing emulsion stability and subsequent treatment requirements, attempts were made to generate a representative lab test transferrable to the field.

A literature search revealed that the cosmetics industry, among others, use centrifugation and rate of phase separation to evaluate stability[6,7]. A pilot test was performed comparing the recommended direct emulsion formulation #28 versus a rejected formulation #8 on the lab centrifuge **(Image 4)**, revealing a correlation.

While both systems showed initial stability, formulation #8 separated during static age. It appeared the centrifuge accelerates separation, providing an indication of instability in advance and allowing for proactive treatment. An electronic bench centrifuge was sent to the field as part of the test kit in an effort to benchmark quantitative values for treatment.

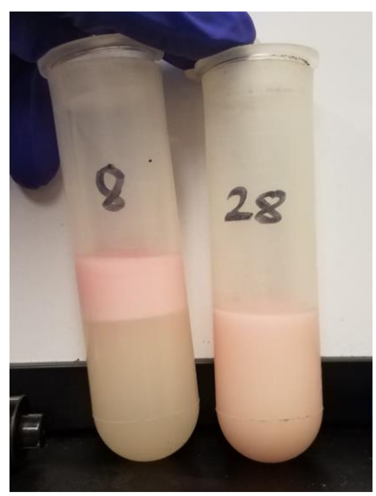

Image 4: Formulation #8 (left) and final formulation #28 (right) after bench top centrifuge

Field Preparation

Introduction of a new drilling fluid system requires a careful review of rig site contingencies. Not all circumstances are able to be replicated in the lab, but steps were taken to prepare for as many as possible.

Risk Assessment and Planning

In collaboration with the operator, Occidental Oil and Gas, guidelines were established to manage risks with a clear plan. Key elements of the plan reviewed well control, gas influx, lost circulation, hole cleaning, torque issues. If the system failed to perform as expected, its basic composition enabled conversion to a conventional drilling fluid to complete the interval.

Yard Mix

A yard mix was scheduled to evaluate large-scale preparation of the direct emulsion system **(Image 5)**.

Image 5: Yard mix tank from the top grating

A 100 bbl batch of the direct emulsion was mixed in a 500 bbl mix tank by adding liquid additives from the top of the tank and dry additives via the mud hopper, circulating fluid via a centrifugal pump. The mix tank was intentionally left dirty prior to the mix to simulate rig tank bottoms contamination.

From laboratory testing, foaming was highlighted as a potential concern. During the yard mix, there were no issues encountered and the fluid remained in the mix tank for a longer period to observe any phase separation and was then shipped to the well location for use in the first field trial.

Field Trials

The first field trial was performed at a well located in Southeast New Mexico. Approximately 1800 bbls of a 9.2 lbm/gal direct emulsion system was blended at the drilling rig, with any extra volume moved to storage in a nearby frac tank. The system blended easily with minimal mixing time and, as with the yard mix, no foaming was observed.

The drilling of the 9 ⅞ inch intermediate hole section commenced, entering the salt zone shortly after the drill-out of the surface casing. Drill cuttings appeared in tact, showing no indication of salt dissolution. Drilling continued with no issues until an increase in volume and mud weight indicated a saltwater flow was encountered.

Saltwater flow issues continued and the increased system volumes were converted to additional direct emulsion volume. The density of the system increased, approaching 9.8 lbm/gal from the influx of brine (water flow with dissolved formation salt), and resulted in some loss of circulation. Losses were addressed by reducing mud weight with additions of diesel and the addition of the stored 9.2 lbm/bbl fluid.

Bench top centrifuged samples showed phase separation similar to the fresh direct emulsion fluid. Additional surfactant was added to further improve the stabilization of the system.

Image 6: Bench top centrifuged samples during saltwater flow (left) and prior to drilling (right)

Fluid loss control, while not a key concern, remained relatively low for a system without a dedicated filtration control additive. API filtration ranged from 5 to 25 cc/30 min with a tight, slick filter cake.

As drilling of the intermediate section progressed, some trips out of the hole were required to change bottom hole assembly tools. Several weighted mud caps were mixed and spotted during these trips to minimize saltwater flows with no issues.

The challenges of the first well, particularly the saltwater flows (below saturation) interacting with the system (diluted direct emulsion external phase to below saturation) and the shallower salt zones (increased washout), limited the overall benefits of the system. Based upon a caliper sweep, washout was estimated at 70 volume % in the salt zones.

A second field trial occurred at a well located in West Texas. In this application, a 12 ¼ inch intermediate hole was drilled using sodium chloride brine from surface casing shoe to 5,000 feet and displaced to the direct emulsion system and drilled the remaining 5,000 feet to section total depth. The system exhibited in specification drilling fluid properties and this time did not encounter any saltwater flows or other noteworthy drilling issues, thus providing the full economic and performance benefits of the direct emulsion system.

Observations

Throughout the deployment phase, several observations were made that improved fluid maintenance efforts. Ensuring the brine phase remains at saturation is critical to salt inhibition. Chlorides were measured using filtrate from the API filter press per the procedure in the API recommended practices.

The chloride titration initially resulted in a value near 140,000 mg/L – well below the expected 180,000 mg/L+ for sodium chloride brine at saturation. Knowing the filtrate contained some oil, the chlorides were re-calculated using the retort oil content for chloride levels. Using this calculation, chloride levels far exceeded saturation, with extrapolated values near 230,000 mg/L.

The drilling fluids specialist then used the bench top centrifuge to separate oil from the filtrate and re-run the titration. The chlorides fell in line with expected results **(Figure 2)**. This surprise leads to the conclusion that the filtrate oil content does not reliably match the overall oil:water content of the direct emulsion. Currently, the field specialists continue to use centrifuged filtrate to track chlorides as a reliable test method.

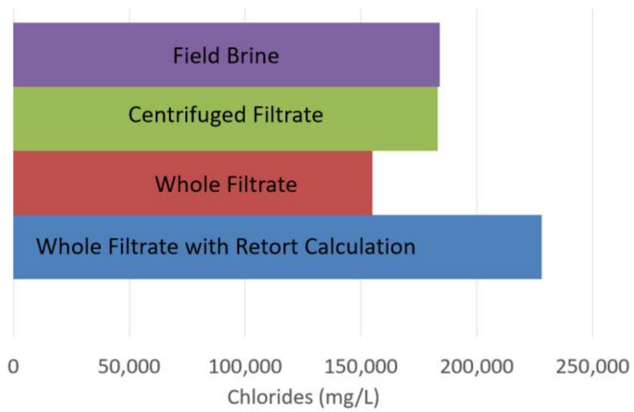

Figure 2: Chloride measurement by test method

The bench top centrifuge provided some insight into stability; however, during events requiring diesel additions, phase separation had greater variance depending on how much blending and shear the direct emulsion received. Surfactant treatment was performed by volume of diesel added.

An observation was made that phase-separation of the filtrate from the API filter press correlated to fluid stability. Stable fluids appeared as one phase in the graduated cylinder. As the system is stressed and requires treatment, the filtrate appears as multiple phases. In a worse-case scenario, free brine was present, but as more surfactant blended into the system, the phase separation diminished **(Image 7)**. This is now a standard observation for system maintenance of the direct emulsion system.

Image 7: Filtrate where system requires treatment (left), system response to treatment (right)

Results

The New Mexico field trial demonstrated the stability of the direct emulsion system, even though the saltwater flows diluted the saturated sodium chloride external phase, thus inducing washout in the salt formations. The Texas field trial confirmed the potential of the system. The direct emulsion drilling fluid was re-used and delivered the expected drilling performance and cost savings.

The overall cost savings includes the continued elimination of a casing interval to isolate the salt zone, the elimination of two-stage intermediate cement jobs and the reduction in cement, and reduced trucking and disposal of liquid waste volumes associated with brine and water based fluid drilling and dilution.

Further optimization includes a more aggressive solids control program to reduce diesel usage to maintain low mud weights and testing to manage product additions at the rig site.

Conclusions

The successful application of a direct emulsion system correlated with extensive laboratory testing was conducted to ensure a stable emulsion and to cover multiple contingencies. This new application offers a new practical use for direct emulsions, with the following conclusions:

- Stable direct emulsion systems are possible in saturated sodium chloride brine solutions
- Pilot and contingency testing effectively screened appropriate stabilizers (surfactants) for field-scale use in saturated sodium chloride brine
- Foaming of the system was not an issue in the field as compared to the lab, likely due to lab mixing versus field mixing methods
- Saturated sodium chloride direct emulsion fluids effectively minimize the dissolution of salt formations thus reducing washout, resulting in significant cost savings through the reduction in dump and dilute waste mud volumes and needed cement for intermediate casing.

Acknowledgments

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