

## New Treatment Reduces Direct Emulsion Drilling Fluid Cost By Recycling System Components, Minimizing Dilution

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### Abstract

Saturated salt direct emulsion systems have eliminated hundreds of casing intervals in the Delaware Basin. Density control to prevent losses depends upon oil additions, which remain the primary cost factor in the direct emulsion system utilization. A new treatment process minimizes oil additions by more than 30% while drilling and allows recycling of the fluid phases at the end of the well.

Direct emulsion systems utilize the non-continuous oil phase to reduce the density of water-based drilling fluids. Accumulated drilled solids increase the density thus requiring additional oil to balance the mud weight. The new treatment system aids in removing more drilled solids thus reducing the volume of oil to be added. Supplemental treatment separates the solids, oil, and brine phases resulting in minimal volumes for solids disposal, while the oil and brine phases can be recycled.

The testing and optimization process required development of new test procedures. The results demonstrated that recovered oil is not impacted by the treatment, allowing for its reuse in both direct emulsion and invert emulsion drilling fluids. With optimal chemical application, brine properties remain sufficient to act as a base for the water-based drilling fluid. As an added benefit, transportation costs declined through the reduction in oil additions and waste volumes.

The direct emulsion treatment advances the maturing technology to expand its application base as economics dramatically improve. The lower cost of ownership makes the system practical for use in new areas outside of the Delaware Basin, including loss-prone horizontal wells and intervals subject to water flows.

### Introduction

Direct emulsion drilling fluid systems date back to the middle of the 20<sup>th</sup> century. Originally, the non-continuous oil phase was an unintended consequence of drilling through prolific crude-bearing zones or spotting around stuck pipe. Drilling performance benefits, such as reduced fluid loss, led to broad adoption for a variety of applications ([Echols 1947](#); [Perkins 1951](#); [Rogers 1963](#); [Wilson 1951](#)).

Over the past several decades, direct emulsion system usage has evolved as a method to lower hydrostatic pressure in water-based systems, particularly in depleted reservoirs ([Collins and Chumakov 2016](#); [Sokovnin et al. 2015](#)). Today, saturated salt

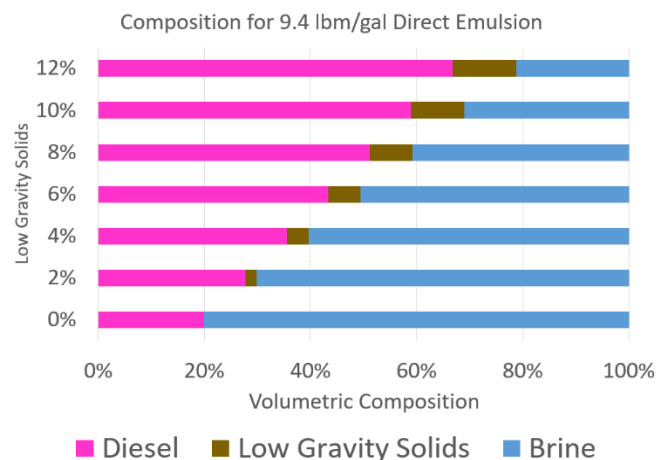
direct emulsion system usage is widespread in the Permian Basin to merge a salt interval with weaker, loss-prone zones below ([Strickland et al. 2018](#); [Willis et al. 2018](#)). The ability to eliminate an extra casing string offers tremendous savings and improvement in overall drilling efficiency.

### Direct Emulsion Economics

The savings of an extra casing string, while highly dependent upon numerous factors, easily amounts to hundreds of thousands of dollars. Many operators have sought greater efficiency in their direct emulsion fluid usage. While the savings in creating a direct emulsion fluid outweigh the cost of diesel, increased oil usage affects other costs as well as logistics.

The ability to reuse direct emulsion systems across wells improves the cost efficiency; however, as drilled solids accumulate, more oil is required to maintain the same density.

The current application requires a density that typically ranges from 8.8 to 9.8-lb<sub>m</sub>/gal. The oil volume is a balance between the saturated 10.0-lb<sub>m</sub>/gal NaCl brine phase and the drill solids (**Figure 1**). Increases in drilled solids require more oil to cut the overall density. In some cases, a fresh fluid starting at an oil:water ratio of 20:80 could end up with an oil:water ratio of 50:50 from the oil additions necessary to balance the weight of the entrained solids.



**Figure 1: Example of oil content required to maintain 9.4-lb<sub>m</sub>/gal mud weight with increasing drill solids (assumptions: 7.0-lb<sub>m</sub>/gal diesel, 10.0-lb<sub>m</sub>/gal brine, 2.6-SG low-gravity solids).**

### **Direct Emulsion Enhancement**

As newer direct emulsion systems became standard practice in the Permian Basin, operators typically sought to utilize the fluid beyond the existing design scope including utilization in the lateral to eliminate extra fluid displacements in short horizontal sections. Given expected torque concerns, the fluid design team initiated a project to design a compatible lubricant for the system.

The other design concept, and the topic of discussion in this paper, are treatments to enhance existing solids control efficiency for minimized diesel dilution as well as separation of the solid, water, and oil phases to lower operational cost.

### **Treatment Concept and Requirements**

The initial design concepts centered on total separation with the idea that complete separation of the phases would reduce the concentration of chemicals required for solids removal treatment.

The chemistry requirements established for the project were outlined prior to project launch:

- The treatment should not irreversibly de-stabilize the direct emulsion system while drilling
- The treatment should not contaminate the oil phase, which may prevent it from reuse in direct emulsion or invert emulsion systems
- The treatment process should occur at the rigsite
- The process should leverage existing equipment found on most rigs in the area
- The treatment must consistently offer a clear cost savings

The development team reviewed a variety of chemical options, leveraging their sister company, [Jacam Catalyst](#)<sup>1</sup>, specializing in emulsions for analytical tools and off-the-shelf options.

Drilling fluid dewatering was considered as the obvious methodology to remove the solid phase. In these applications, a flocculant, frequently in combination with a coagulant, is used to bind fine particles into larger ones for enhanced removal, typically through a centrifuge ([Malachosky et al. 1991](#); [Sinanan 2003](#)).

Dewatering additives are widely available and the technology is used in drilling operations with proven success ([Nordquist and Faucher 1988](#)). Unfortunately, simple dewatering additives did not appear to work straightforward in more complex systems such as direct emulsion drilling fluids containing multiple phases. The risk of system contamination or de-stabilization required further examination and testing.

A review of existing technologies also considered one or a combination of options for equipment. On rigs with quality solids control equipment and personnel, dilution rates were lower. While this is difficult to quantify for every case, it is clear that poor equipment and/or poor utilization increases overall fluid cost.

Logistic and cost considerations dictated that the system

must not require major changes to equipment. Given the criticality of solids control equipment already, most rigs are equipped with decanting centrifuges. However, performance and adjustment capabilities varied, limiting the potential to fine tune operating parameters for optimized solids control efficiency.

Previous work with customers to upgrade solids control equipment faced numerous challenges including limited availability and a shortage of qualified operators. Additional personnel increases cost and was considered an unacceptable option.

The drilling fluids company does not include provisions for solids control equipment; however, it employs experienced solids control experts to ensure the best performance of its drilling fluids. These solids control experts took a lead role in determining the best options for treatment evaluation and overall collaboration with outside parties to ensure the success of the treatment.

### **Test Methods**

The highly variable nature of drilling fluids, particularly emulsion fluids, requires a robust test method that accounts for many unknown factors. For example, a laboratory fluid has a completely different shear history relative to a field sample and behaves somewhat differently. For all tests, both fresh and field samples were part of the test matrix.

Testing was separated into a solids removal phase and a liquid separation phase. In both treatments, most test methods involve a “guess-and-check” approach using bottles and broad screening to observe for best performance. Many of these product lines include small kits that are sent to the field for this purpose ([Gallus et al. 1958](#)).

The first phase of the study was initiated to determine the efficacy of various flocculant additives and their ability to separate the solids from the direct emulsion fluid. Products were qualified based on the following parameters:

- Volume and degree of oil and brine separation
- Solids compaction
- Centrifuge power needed
- Amount of additive needed

Desired results included increased solids removal via centrifuge compared to untreated samples without breaking the direct emulsion. Lab centrifuge rates needed to translate to field application, and lower additive concentrations were preferred for cost and logistic considerations.

Testing involved a range of additives at specific concentrations, and the best performing additive at the lowest concentration was used for further testing. As part of this testing, barrel-equivalent measurements (350 mL) of the direct emulsion fluid were poured into 50-mL centrifuge tubes. The aliquots were dosed with the selected additive and placed into a laboratory centrifuge. Samples were spun at both low and high power at a residence time similar to that which is used in field applications. Upon centrifugation, the resulting effluent was

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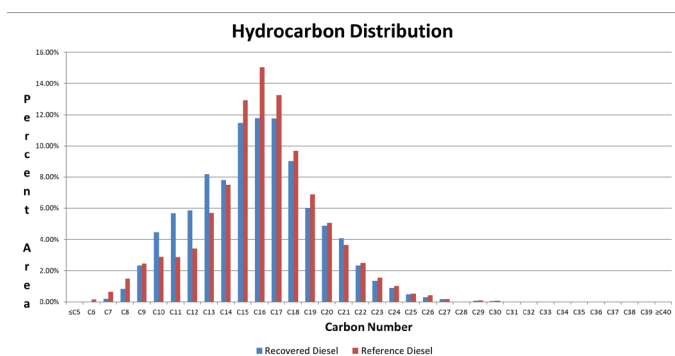
<sup>1</sup> [www.jacam.com/fluids-separation/](http://www.jacam.com/fluids-separation/)

observed for phase separation and qualified based on the parameters listed above.

The second phase of the study involved the same test method as above, this time focusing on the addition of a surfactant/breaker additive independently and in conjunction with the flocculant additive in order to break the direct emulsion and separate the liquid components. The potential surfactant/breaker additives were judged using the same parameters as the flocculant additive. A retort of the direct emulsion fluid was measured to determine the volume percent of both oil and water as a theoretical limit. From there, the oil from the recovery process could be used to determine the efficiency of the method and quantify an oil yield percent.

Gas Chromatography – Flame Ionization Detection (GC-FID) testing was performed on recovered diesel to determine hydrocarbon distribution in order to measure any changes in the hydrocarbon composition of the diesel caused by the recovery process. Results showed similar hydrocarbon distributions to a reference diesel.

Additionally, Gas Chromatography – Mass Spectrometry (GC/MS) testing was performed to detect trace levels of organic contamination found in the diesel from the recovery process. Upon analysis, no contamination of the diesel phase was detected.



**Figure 2: Gas chromatography results showing comparison of hydrocarbon distribution between recovered diesel (treated) and a reference diesel.**

### Laboratory Findings

Chemical performance can be highly variable depending upon the drilling fluid system. Many development projects utilized basic bottle testing and settling tests to determine the best option before field use.

For the complexity of a direct emulsion system, there were many unknowns and questions as to how to evaluate risk before a field trial. Some additives risked breaking the emulsion system in unpredictable ways. Others could introduce excess viscosity at high concentrations. Many conventional products appeared to introduce fluid instability risk in a worst case scenario or increased emulsifier cost to maintain the system as a best case scenario.

Iterative trial-and-error testing established frontrunners for the flocculant and surfactant additive with respective concentration ranges for solids removal and liquid separation. Additionally, benchmarks were set for centrifuge parameters

such as G-Force and residency time. These findings provided expected treatment ranges for yard testing.

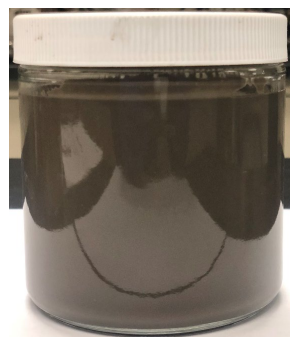
### Yard Test

Performance results in a yard or scale-up test was deemed the best qualification for the potential chemicals and process identified by lab testing. The test program included attempts at solids removal and total phase separation. Direct emulsion drilling fluid from the field was shipped in totes to the test location.

The planned matrix included analyzing untreated direct emulsion fluid, direct emulsion fluid with the solids treatment, and direct emulsion fluid with the emulsion breaker in conjunction with the solids treatment. Due to volume restrictions at the site, the established laboratory concentrations would be tested first to create working and storage volume for other testing.

For each test, the product was injected using precision dosing pumps at the suction end of the feed pump to the centrifuge. Samples were captured of the discharge and effluent for analysis. Visually, clear phase separation was observed with excellent solids removal (**Figures 3 and 4**).

The retained samples were tested for composition and residual chemical. There was no contamination of the diesel, as desired, and initial results presented an acceptable correlation to laboratory testing to continue with the recommended product concentrations.



**Figure 3: Direct emulsion system prior to treatment**



**Figure 4: Broken emulsion following breaker treatment**

### Field Deployment Considerations

The yard test provided sufficient data to propose a field trial to existing customers, but several considerations were required for a proposal.

The treatment chemistry would be sold as a mud additive, and collaboration with the operator and the on-site solids control company would be essential for deployment. The drilling fluids provider's goal was to use its solids control experts to assess equipment to improve drilling fluid economics – not to run the equipment on a daily basis. The concept of the offering is that existing field personnel can perform the basic operation once the equipment is connected and chemical is on location.

**Field Trials**

The drilling fluids provider approached several customers with the treatment concept and yard test performance data seeking a field trial. A solids control expert from the drilling fluids provider, along with a technical support specialist, were present at the rigsite to oversee the setup and capture critical data for each trial.

**Trial #1**

The first trial occurred on the West Texas side of the Delaware Basin in Ward County. The rig featured one 18-in. decanting centrifuge with no onsite personnel and minimal adjustment features. Many setups in the area feature dual centrifuge setups and an operator on location at all times. This was not considered ideal for a first trial; however, it provided an opportunity to optimize the system under challenging circumstances.

The 12¼-in. interval using the direct emulsion system presented a significant challenge for mud weight maintenance. Instead of drilling the salt formation with saturated brine and displacing to direct emulsion system, the operator chose to drill out the shoe with the direct emulsion system.

The large hole size, combined with the very high rates of penetration, overwhelmed the circulating system. Fine salt solids readily passed through the equipment setup and raised the mud weight well over the programmed 9.5-lb<sub>m</sub>/gal.

Effluent density was recorded before and after treatment, showing a reduction of 0.4-lb<sub>m</sub>/gal in mud weight. Through dilution with fresh drilling fluid volume and the treatment method, the mud weight was returned to target specifications before drilling into the loss-prone zones.

A key challenge was the inconsistent feed from the centrifugal pump into the centrifuge (Figures 5 and 6). Inconsistent feed resulted in inconsistent treatment, increasing chemical consumption, and introducing uncertainty with actual treatment levels. Moving forward, positive displacement pumps became standard equipment.



Figure 5: Centrifugal pump discharge



Figure 6: Centrifugal pump discharge a second later (no fluid)

**Trial #2**

The second trial was also in West Texas. The rig featured a dual centrifuge setup with an onsite operator. The well program

featured a similar plan to trial #1 with a 12¼-in. hole drilling out the shoe with direct emulsion fluid. Table 1 shows the mud weight, solids content, and oil:water ratio for Trial #2.

In this application, operational performance was far more consistent. With the exception of an incident in which solids control personnel packed off the centrifuge by processing shaker belly underflow at rates intended for the active circulating volume, the 9.5 to 9.7-lb<sub>m</sub>/gal mud weight range was maintained using only the necessary dilution volume required by losses on cuttings. When the centrifuge was operational, no extra diesel was added to lower density from solids throughout the 9,000-ft interval.

After addressing the packed off centrifuge, the oil:water ratio was maintained within ±3%. An additional 0.2-lb<sub>m</sub>/gal cut was seen at the centrifuge effluent while the treatment process was online. At interval TD, low-gravity solids were reported at 2.2%. The direct emulsion system was recovered and stored for reuse in near pristine condition.

Measured Depth (ft)	1,655	3,200	4,282	5,489	6,170	7,100	7,696	8,549	9,326	9,830	10,581
Mud Weight (lb <sub>m</sub> /gal)	9.5	10.5	10.1	9.7	9.7	9.6	9.5	9.6	9.5	9.5	9.7
Solids Content (%)	10.4	16.3	13.7	11	10.9	10.3	10	10.6	9.7	9.7	10.9
Low Gravity Solids (%)	3.7	8.5	5.1	2.6	2.5	2.0	2.0	2.8	1.1	0.8	2.2
Oil : Water Ratio	33 : 67	18 : 82	21 : 79	25 : 75	24 : 76	25 : 75	26 : 74	24 : 76	23 : 77	22 : 78	23 : 77

Table 1: Mud properties illustrating fluid maintenance while treating with solids removal application for Trial #2.

**Trial #3**

The third field trial was performed in Eddy County, New Mexico. This rig also featured a dual centrifuge setup with an onsite operator. The well program dictated a 9⅞-in. hole drilling out the shoe with direct emulsion fluid.

The direct emulsion system was received from a previous well and supplemented with fresh volume built at the rig site. Table 2 shows the mud weight, solids content, and oil:water ratio for Trial #3. The specified mud weight range of 9.0 to 9.2-lb<sub>m</sub>/gal was controlled throughout the 10,000-ft interval using minimal diesel dilution. Compared to an offset benchmark well, diesel consumption was reduced more than 60%.

An additional 0.3-lb<sub>m</sub>/gal cut was seen at the centrifuge effluent while the treatment process was online. On the last day of drilling, low gravity solids were reported at 2.3%, ensuring excellent quality fluid for reuse on future wells.

Measured Depth (ft)	810	1,675	3,976	5,000	6,240	7,931	8,339	9,288	9,827	10,302	11,155
Mud Weight (lb <sub>m</sub> /gal)	9.0	9.2	9.2	9.2	9.1	9.1	9.0	9.0	9.1	9.0	9.1
Solids Content (%)	7.7	8.6	9.1	9.4	8.7	8.9	8.3	8.3	9	8	8.4
Low Gravity Solids (%)	3.8	2.3	3.6	3.6	2.8	3.2	2.7	2.6	3.4	1.4	2.3
Oil : Water Ratio	38 : 62	34 : 66	38 : 62	41 : 59	41 : 59	44 : 56	45 : 55	45 : 55	44 : 56	39 : 61	38 : 62

Table 2: Mud properties illustrating fluid maintenance while treating with solids removal application for Trial #3.

## Current Status

Across a small number of wells, it is difficult to characterize exact savings from the treatment. Water flows, losses, and other unplanned events complicate the calculations even further. The authors are confident that with more applications, a larger sample size will back up the significant savings that are hinted at by the current data. Some of these anticipated savings include:

- In many cases, the oil:water ratio of fresh drilling fluid is within 1-2% of the oil:water ratio at total depth.
- A review of historical data using 30 wells prior to the treatment's deployment demonstrate that diesel consumption falls in the 30<sup>th</sup> percentile in new wells.
- To date, the treatment has been used to control low-gravity solids accumulation on more than 30 wells. In a typical case, this results in a savings of about \$25,000.

There has been little interest in emulsion separation. The highly variable economics along with considerably less oil in the systems makes the value proposition less appealing than initially expected.

Positive displacement pump availability from solids control companies is an issue. The drilling fluids provider maintains a very small fleet of their own for emergency backup and special cases where proper equipment is unavailable. In most cases, the solids control provider can secure the equipment, particularly as the success of the system continues to generate significant savings.

## Conclusions

Direct emulsion systems are complex systems and the cost of oil is a substantial driver in overall economics. Key findings through the development and deployment process are as follows:

- Low-gravity solids dramatically impact diesel consumption.
- The treatment process has the ability to lower diesel consumption by 30% in many cases, resulting in significant savings.
- It is not uncommon to have oil:water ratios remain somewhat constant from fresh fluid to total depth. This limits the economic necessity of breaking the emulsion to recover diesel.
- Breaking the emulsion is highly variable based upon chemical treatment, shear history, and other unknowns. The uncertainty of the amount of recoverable oil, chemical cost, and the untreated excellent condition of the fluid with solids removal limits the practical necessity of this process in most cases.
- The treatment method enables greater adoption of direct emulsion drilling fluid in marginal conditions
- Success depends on commitment of all parties involved – operator, solids control experts, and drilling fluids specialists

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