

## Direct Emulsion Fluid Improves Performance and Reduces Cost in the Permian Basin

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### Abstract

The M-I SWACO direct emulsion drilling fluid system was designed to drill the intermediate sections and reduce overall drilling costs in the Permian Basin. The wells in the area are prone to tremendous washout of the salt in addition to high volumes of water influx making it difficult to drill the section with one conventional drilling fluid. The drilling fluid utilizes saturated field brine and emulsifies diesel to control the density as needed while drilling. It tolerates the contamination presented in various types of drill solids, water influx events, and sour gas while maintaining excellent emulsion stability. In field trials, the system was formulated for an 8.9-9.8 lb/gal weight fluid (1.07-1.18 S.G.) to drill the intermediate sections. These properties reduce washout and the cost of drilling when compared to other drilling fluids. The drilling fluid successfully drilled the intermediate sections of the two pads in the Permian Basin.

### Introduction

Improving drilling efficiency in the Permian Basin remains a priority for operators while simultaneously reducing the total cost of drilling a pad. Several challenges are presented to drillers in the pursuit to total depth (TD). In many areas, the presence of salt formations, water influx events, followed by depleted formations make the journey to TD difficult. The presence of hydrogen sulfide gas requires elevated safety practices to be observed. Various formulations of water-base and oil-base drilling fluids have been trialed to limit the effect these challenges present.

In many situations, economical water-base drilling fluid is used to drill the intermediate sections of these wells. Field brine is employed due to availability, performance, and cost. As the field brine is used to drill through the salt formation it saturates to roughly 10.0 lbm/gal. Washout of the salt have been reported at values over 40% due to the addition of fresh water for density control. Large volumes of washout make proving cement to the surface a challenge, which is problematic when drilling in the Permian Basin where it's required. The 10.0 lbm/gal weight can prove to be too heavy for the deeper depleted formations which gave rise to whole mud loss. The fluid must be diluted with fresh water to reduce the density, which generates an issue with volume on site. This "dump and

dilute" method increases the cost of drilling, relies on trucking availability, and increases open hole washout through the exposed salt section.

The option of oil-base mud in the intermediate section will minimize open hole washout and density can be maintained to the desired levels. While undesired washout is avoided, water influx events lead to severe fluid contamination. Costly diesel additions are necessary to maintain the fluid. If the water influx is significant enough, the fluid cannot be used to drill with and must be disposed of resulting in an increased cost. Whole mud losses through the depleted zone will also quickly increase the drilling costs.

### Direct Emulsion Drilling Fluid

The need for a drilling fluid that can minimize washout, maintain functional rheology/stability with water influx events, handle low gravity solids (shale, anhydrite, and sandstone) and the ability to adjust density was clear. A direct emulsion system was developed as a solution to challenges encountered while drilling in the Permian Basin. A direct emulsion drilling fluid has been used in the past in the region and internationally. To achieve these goals, field brine was utilized in conjunction with diesel to reduce the density from 10.0 lbm/gal and keep costs low. This type of drilling fluid has water or brine as the continuous phase with an internal oil phase that lowers the density to desired levels. The emulsion is formed through the application of mixing energy and the emulsifier.

The components of the drilling fluid would ideally be safe to handle, no caustic, have low HMIS ratings in all categories, and not require HAZMAT certification for transportation. Additional products would need to be compatible with high salinity environments and the intrinsic hardness from calcium and magnesium ions to eliminate the need to pre-treat the brine.

Some of the key features of the drilling fluid system are below:

#### Key features of the direct emulsion system:

- Formation brine can be used as the external phase, which reduces washout of formation salt and maintain the wellbore stability

- No need to treat out the calcium and magnesium ions in the formation brine
- Lime used to adjust pH
- Mud weight is controlled by the oil content
- More cost effective when compared to an invert emulsion fluid system
- Able to be weighted up with barite in case of a well control event or slug
- Excellent lubricity
- Minimal products required

To further reduce overall drilling costs, a method was established to reuse the diesel, the most expensive component of the system. The emulsion is broken allowing the oil to be reused in the subsequent lateral sections where oil-base mud is typically used in the region. The recovered diesel can be used to build drilling fluid or for dilution purposes. The ability to reuse the base oil reduces the overall consumption, but also aids in reducing trucking and lowering the total disposal volumes, which adds a significant impact on the overall cost of drilling.

### Development in the lab

In the development process, several emulsifiers were tested to prepare a stable emulsion using the local field brine. Most of the emulsifiers could not form a stable emulsion with the brine or the HSE profile was not acceptable for use (figure 1). Others formed invert systems with electrical stability (ES) values over 50 V, raising a red flag. Water-base mud should be conductive resulting in an ES value of zero. An increased ES value is observed when oil is the external phase due its resistive properties.

When selecting the emulsifier, a wide range of oil to water ratios (OWR) were tested, including 10:90 to 50:50. Water is required to be the external, continuous phase at all OWR, and the emulsions are stable with rheological properties within normal conventional drilling fluids. Challenges were encountered during development of the fluid design due to the salt chemistry of field brines. Once an emulsifier was found and the system formulation finalized the standard testing was completed.



Figure 1. Examples of emulsifiers used to develop the direct emulsion. The left image was unsuccessful, while the right image illustrates a stable direct emulsion.

The rheology of the drilling fluid system was measured using API 13B-1. Table 1 shows the rheology values at different points throughout the development process and drilling. It compares the values before hot-rolling (BHR), after hot-rolling (AHR), the fluid mixed in tanks in the field, during drilling, and after a water influx event. The desired rheology profile would allow for high pump rates and good hole cleaning.

Table 1. Rheology of the direct emulsion drilling fluid

	BHR	AHR	Premix	Drilling	After Influx
Lab/Field	Lab	Lab	Field	Field	Field
Density	9.0	9.0	9.0	9.1	9.3
PV	15	15	12	12	11
YP	22	15	11	12	10
pH	10	10	9.55	9.33	9.02
ES	0	0			

The direct emulsion system went through standard API contamination testing and further in-house verification and validation to ensure excellent fluid performance in the field and have treatment protocols in place. The system was tested with the different contaminants (evaporated salt, rev dust, and API standard evaluation clay) at 35 ppb loading and cement at 10 ppb. All samples were hot rolled for 16 hours at 150 F. The cement contaminated sample performed better with a citric acid pretreatment. Two other common contaminations encountered in the Permian were tested. Gypsum and formation salt (evaporated field brine) were added at 35 ppb and hot-rolled overnight at 150 F. The rock salt test resulted in a 93% recovery of the solid with the size of the particulate rock close to the original size. This was done to illustrate the minimal risk of washout. A stable emulsion was observed in all tests other than rev dust where minor separation was observed. More information is in Figure 2 below. The lubricity of the fluid was also compared with a common OBM and field brine using an OFITE Lubricity Tester, as seen in Table 2. The coefficient of friction of the direct emulsion was measured to be significantly less than field brine and comparable to OBM. Corrosion testing with carbon steel coupons showed that the direct emulsion had an acceptable rate of 2.2 mpy. After thorough lab testing the formulation was approved for a field trial.

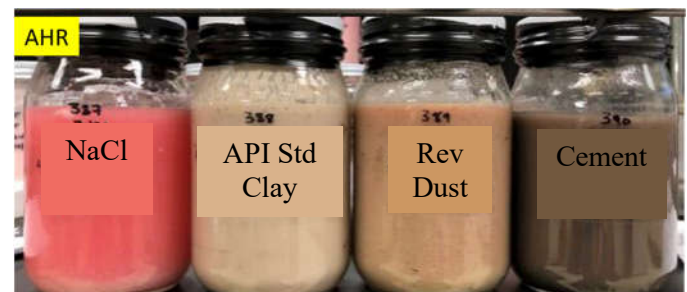


Figure 2. The direct emulsion system after four API contamination tests and hot rolling for 16 hours in a 150 F oven.

Table 2. Lubricity of direct emulsion and field brine samples using an OFITE Lubricity Tester.

	Coefficient of Friction
Direct Emulsion	0.08
Field Brine	0.29
Diesel	0.07

### Field Trials in the Permian Basin

The direct emulsion system was field trialed in Texas and New Mexico to drill the 12 ¼" intermediate sections of three-well pads. Both areas were prone to losses and water influx events. The cost of drilling the intermediate sections with acceptable performance had become too high and an alternative approach was needed. The technical objectives for the field trial are below:

#### Technical objectives for a successful field trial are:

- Mixing performed on the rig with standard equipment
- Stable emulsion maintained through drilling and running casing with no phase separation
- Rheology be maintained within specifications through dilution and usage of solids control equipment (SCE)
- Optimize SCE protocols – centrifuge speeds and screen sizes
- Validate chlorides testing procedure in field
- Drill the well section to TD without any fluid related issue and comparable ROP
- Check the hole size through pumping sweeps and calculate washout
- Run casing to desired depth
- Minimize formation losses as compared to offset wells, incorporate LCM plan
- No corrosion issue on drill string or downhole tools
- Torque and drag less than a conventional water-base fluid
- Break the emulsion at the end of batch drilling
- No HSE issues

The initial field trial was completed around Midland, TX for the intermediate sections of a three-well pad. The system was mixed on site using field brine from the area (10.0 lbm/gal). The emulsifier and other components were added in mixing tanks and enough diesel to reduce the density to 9.0 lbm/gal (Figure 3). Several batches of the fluid were prepared and circulated in the tanks daily until drilling began. No instability of the system was observed. The ROP and hole cleaning were comparable with other drilling fluids used in the basin. There were numerous water influx events and hydrogen sulfide gas was detected. The gas reduced the pH of the drilling fluid and lime was added to return the pH to around 9. The average volume of water influx was measured at over 1500 bbl per well. At times the influx was 200 bbl/h. The emulsion stability remained stable and no free oil was observed in the

pits. The centrifuges were run at full speed to remove low gravity solids without separating the emulsion. Diesel was added to maintain the density and offset the weight of the drilled solids. There was no issue observed with regards to emulsion stability or rheological properties when the system was weighted to 10.5 and 11.4 lbm/gal with barite for trip slugs. Various LCM were tested to be compatible with the direct emulsion fluid. LCM pills were pumped as needed and effective at controlling losses. Once the section was completed, there were no signs of accretion or bit balling.

The performance of the fluid was compared to OBM and WBM used on similar offset pads. The washout was measured at 10-13%, which was comparable to OBM in the area. This was a significant improvement to the 40% observed with fresh WBM. Casing was run without incident and the two stage cement jobs were confirmed to surface with excess. No corrosion was noted. The cost of drilling was reduced by 20% when compared to an OBM pad with less water influx.



Figure 3. The direct emulsion system mixed in tanks prior to drilling.

The second field trial was completed near Carlsbad, NM to batch drill the intermediate section of a three-well pad. The system was again mixed in location using local field brine (10.0 lbm/gal). The emulsifier along with other additives were mixed with diesel to reduce the density to 9.5 lbm/gal. Several batches of the system were prepared for the volume needed to begin drilling the 12 ¼" section. No emulsion instability was observed in the tanks or pits during preparation or drilling. The system handled water influx events successfully.

The average measured washout for the pad was less than 3%, which is slightly better than OBM (5%) on offset wells in the area. Previous brine systems had immeasurable washout and 600% excess cement was reportedly pumped. The water

influx rate in New Mexico (9-12.5 bbl/h) was much lower than what was experienced in the initial trial. The wells had successful casing runs and cement back to surface. The cost savings when compared to OBM were higher in the New Mexico trial. The diesel costs savings using the direct emulsion was between 54 and 60% per pad. The total drilling fluid cost (not including diesel or brine) was 46 and 62% less expensive.

### Breaking the emulsion and diesel recovery

Even with an increase in oil prices, operators remain cost sensitive and are hesitant to change current practices unless a clear value is shown in a technology or process. The ability to reuse the emulsified diesel in the direct emulsion would bring an apparent added value. The cost of diesel is a significant portion of the drilling fluid bill and will help reduce the total cost of drilling.

The process for to reuse of diesel has been proven in the lab. It was demonstrated with fluids prepared in the lab and drilled in the field. In most samples, roughly half of the diesel was recovered. Figure 4 shows the diesel separated from the emulsion. A sample of OBM was prepared with the recovered diesel with the rheology, fluid loss and ES values comparable to field samples of OBM used in the Permian. In the field, once it's determined that the direct emulsion fluid will not be used for further drilling, the emulsion would then be broken on site and allowed to separate in tanks. The separation time can be substantially reduced by utilizing a centrifuge. The economic impact of reusing half of the diesel would not only reduce the cost of the drilling fluid, but also reduce trucking and disposal costs.



Figure 4. The left image is of a salt contaminated sample and the right image is of the diesel recovered and remaining emulsion.

### Conclusions

- A direct emulsion system was developed in for use in the Permian Basin.
- The fluid formulation uses minimal products and with components with a low HSE profile.
- The direct emulsion handles contamination presented in wells from the region.
- The ROP and torque and drag were comparable to other offset wells in the area using conventional drilling fluid systems.

- The direct emulsion provided a very stable emulsion during the field trial under dynamic and static conditions.
- The wells were successfully drilled and the intermediate casing was subsequently run and cemented in place.
- The direct emulsion reduced the cost of the drilling fluid from 20 to 62% when compared to OBM.

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### Nomenclature

*F* = Degrees Fahrenheit  
*API* = American Petroleum Institute  
*h* = Hour  
*HMIS* = Hazardous Materials Identification System  
*HSE* = Health, Safety and Environment  
*LCM* = Lost Circulation Material  
*mpy* = Mil per Year (1 mil is one thousandth of a inch)  
*OBM* = Oil-base Mud  
*ppb* = Pounds per Barrell  
*ROP* = Rate of Penetration  
*S.G.* = Specific Gravity  
*WBM* = Water-base Mud  
*V* = Volt

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