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Saturated Salt and Diesel Emulsion Fluid Reduces Drilling Costs in New Mexico

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Abstract

In the Delaware Basin of New Mexico, shallower formations, such as the Salado, include halite and anhydrite layers followed by weaker formations in the Delaware Sands- (e.g., the Brushy Canyon). The fracture gradient difference between these two zones has typically required an intermediate casing string to seal off salt formations before reducing fluid density to drill ahead into the Delaware Sands and deeper shale sequences. Achieving an effective three-string well design with one cased intermediate section requires significant fluid density management to help prevent lost circulation, which is impacted by the dissolution of salt into the mud system.

A range of drilling fluids has been used in previous wells having three-string casing designs in the Permian Basin. Over time, unsaturated salt fluids invariably wash out the halite, leading to increased mud weight (MW) and hole enlargement, which requires an increased cement volume. As a result of rigorous laboratory experimentation, careful planning, and successful execution, a direct emulsion water-based drilling mud (DEWBM) was applied in the field to address these challenges. The DEWBM system maintained salt saturation, as evidenced by the return of salt cuttings to surface, and reached fluid densities as low as 9 lbm/gal. Emulsifying oil in saturated sodium-chloride brine enabled this DEWBM to advance as a potential fit-for-purpose solution.

The results obtained while drilling with the DEWBM system in trial wells are compared with those from offset wells drilled using other fluids. Early indications show heightened efficiency and reduced total well costs.

Introduction and Background

Individual oil- and gas-containing basins or fields present unique challenges to drilling. The Permian Basin, which comprises the Delaware Basin, Central Basin Platform, and Midland Basin, located in West Texas and Southeast New Mexico, is no exception. Drilling has been performed in this basin since the 1920s, and with ever-improving technology, deeper and longer horizontal wells are now the norm. Technological advancements have also led to greater efficiency and ultimately lower costs per barrel of oil produced, but continued improvements in efficiency and cost reduction are still needed in the current market.

One method to reduce horizontal well costs is through well design, and where possible, eliminating strings of casing while still meeting regulatory requirements and production goals. To drill horizontal wells into the deeper Bone Spring and Wolfcamp producing formations, a four-string casing design is historically required. This includes surface casing set to 500 to 2,000 ft to protect any freshwater aquifers (as per regulations), the first intermediate casing set below the halite (salt)/gypsum formations (Ochoan series) to 3,000 to 5,000 ft, the second intermediate casing set below the Delaware Sands group (Guadalupian series) to 8,000 to 10,000 ft, and casing or a liner run to horizontal total depth (TD) in the production section (**Table 1, Figure 1**).

The goal was to reduce well costs by moving to a three-string casing design, combining the first intermediate section across the Ochoan series and the second intermediate section across the Guadalupian series into one section.

When eliminating one string of casing in the intermediate section of this well type, two drilling challenges were encountered. The first was handling the halite- (salt-) bearing formations, such as the Salado, encountered in the Ochoan series. These formations are normally drilled using a saturated sodium-chloride brine (~10 lbm/gal) to help minimize the dissolution or washout of the salt zones. In New Mexico, regulations require the cement for the intermediate casing to reach surface. If these salt formations are washed out and the hole size is significantly increased, an excess of cement is needed to seal the casing in place.

The second challenge occurs in the Guadalupian series and can also occur in some areas in the deeper Leonardian series. Formations in these series tend to have lower fracture gradients (<9.5 lbm/gal) (some are severely depleted) compared to the Ochoan series formations. Therefore, when drilling the upper salt zones with saturated sodium-chloride brine (~10 lbm/gal), once the Guadalupian/Leonardian series formations are reached, brine begins being lost to the formation. If the brine is cut with fresh water to temporarily reduce the density, the cut brine eventually reaches saturation during circulation and increases in weight as it encounters the shallower salt formations in the annulus, thus washing out these salt zones even more.

Another option to help minimize lost circulation resulting from high MW is to displace to a highly viscous water-based mud (WBM) once below the salt zones. Various bentonite based and attapulgite based muds have been used because of their high viscosity. These highly viscous muds have a lower MW, and the high viscosity is intended to slow the salt dissolution or washout in the annulus. As drilling continues with these highly viscous muds, salt dissolution from the salt zones still occurs, resulting in a MW increase, and the mud is dumped and replaced with lighter mud. This process is better known as "dump and dilute." However, lost circulation would occur if the MW was not kept low, and the salt zones would still be washed out. In some areas, such as New Mexico, all drilling waste mud and solids are required to be hauled from the drilling location and disposed, resulting in high costs associated with the dump and dilute process and building the extra needed mud.

Considering such challenges in this long, single, intermediate section of the well, research was conducted on alternative drilling fluids to meet the objectives of reducing salt dissolution (washout), lost circulation, cement volume, liquid waste, and, of course, costs. As a result, a DEWBM was studied. Various versions of DEWBMs have been used in the Permian Basin (**Ref. 1**), Russia (**Ref. 2 and 3**), Venezuela (**Ref. 4**), Mexico, and other areas.

Most of this earlier work with DEWBMs used emulsifying oil in fresh water, which lightened the MW, thus preventing lost circulation in low-pressure reservoirs but also preventing oil-wetting issues in the reservoir caused by the use of an alternative nonaqueous drilling fluid (NADF). The DEWBM for the Permian Basin needed to use a lightweight oil, most likely diesel, emulsified in a saturated sodium-chloride external phase.

Fluid System Optimization

The challenge was to develop and test a DEWBM that would meet the following objectives, ultimately reducing well costs:

- Allow continued cost savings through the implementation of a three-string versus a four-string casing design
- Allow no reduction in drill rate
- Reduce salt formation dissolution and washout resulting in an enlarged borehole
- Reduce or eliminate lost circulation in the Guadalupian and Leonardian formation series through the reduction in MW below the fracture gradient
- In New Mexico, reduce the amount of cement necessary to cement intermediate casing and get cement to surface
- Reduce costs associated with building mud to support a dump and dilute method, as observed with viscous WBMs
- Reduce disposal costs of waste liquid mud resulting from the dump and dilute method
- Reduce costs by reusing the DEWBM system from well to well

A series of perceived requirements and properties were established for development and testing to help ensure the DEWBM would be able to withstand potentially encountered contaminants in the Permian Basin. These requirements consisted of

- External phase—saturated sodium-chloride brine
- Internal phase—diesel
- Stable direct emulsion up to 200°F
- pH >10
- Tolerant to drill solids
- Tolerant to salt contamination
- Tolerant to cement contamination
- Tolerant to acid gases exposure [hydrogen sulfide, carbon dioxide (CO_2)]
- Ability to work in local sodium-chloride field brine
- Ability to work with common corrosion inhibitors and scavengers
- Good hole cleaning properties
- Ability to weight up with barite if a well control event was encountered

What is a Direct Emulsion?

A direct emulsion is a dispersion of oil droplets in an aqueous fluid. The most common type is known as a macro-emulsion, in which the fluid appears milky white and the oil drops are at least several microns in size. Because this was the original form of emulsion used for drilling fluid applications, the water-in-oil version of emulsion fluids (NADF) became known as inverted or an "invert emulsion."

The first applications of direct emulsions are reported around the 1930s. Performance characteristics of early DEWBMs were consistent with WBM containing free oil or a loosely emulsified oil phase. Drillers reported immediate benefits, such as reduced bit-balling, lower torque and drag, less sticking, and increased rates of penetration (ROP) (**Ref. 5**).

DEWBM Development and Testing

To develop the three-string drilling fluid design, laboratory work was initiated around July 2016. Speed to market is always desirable for development programs, yet the primary aim was to achieve a quality product that would outperform the existing solutions, significantly lower well costs, and be sustainable for future use.

The progression of testing followed a long-standing process wherein target properties were defined, candidate solutions were qualified for basic function, and then these solutions were stressed to a wider scope of conditions to closely simulate actual working conditions. In parallel, there are a number of other functions that had to be addressed with regard to eventual field deployment (**Table 2**). While several early test samples provided a stable emulsion, it was almost 1 year before a field-ready system was achieved.

Based on proven principles of emulsion stabilization, energy in the form of mixing shear is necessary to disperse the oil into fine droplets within the external brine phase. Then, a specialized surfactant, often called an emulsifier, is necessary to lower the tension at the interface and preserve the distinct oil droplets against coalescence and eventual phase separation.

Some previous DEWBM fluids used relatively high concentrations of biopolymers, so for this situation, an additional challenge was to achieve emulsion stability with minimum polymer content and a low fluid viscosity (**Ref. 6**). The first series of emulsifier candidates included existing materials already available in the laboratory. These were screened with 10 lbm/gal sodium-chloride brine and 20% by volume diesel. Minor amounts of viscosifier and filtration control additives were included, along with caustic soda, to complete the early DEWBM formulas.

Laboratory mixer shear covers a broad range but is not believed to ever equate to the level of hydraulic shear when a fluid is circulated through the bit jets with hundreds of pounds of pressure drop. This was a key consideration as testing progressed because some emulsifiers need more shear to become effective.

Results and Discussion

The assortment of surfactant materials considered for the key role of the emulsifier in the new DEWBM system included a broad range of charge types and chemical compositions. **Table 3** shows the characteristics of the five primary examples.

Samples A, B, D, and E were liquids with some water solubility. Sample C was the only solid, oil-soluble product considered. Although some solid emulsifier products have niche use in areas with cold temperatures, they sometimes need more time to mix, require additional heating to dissolve, and can interfere with the oil-water interface. Mixing in the laboratory on a standard multi-mixer would eventually provide sufficient shear and heat to allow Sample C to work, but when short mixing intervals at ambient temperature were used, undispersed solid surfactant and rapid phase separation were observed.

When a Silverson® high-shear mixer was used in early stages of the project, many surfactant options showed promising initial results. For this reason, an abbreviated mixing time followed by heat stress (hot rolling at 150°F for a period of 16 hours) was used to determine the best performers. **Table 4** shows observations for emulsifier performance in base brine-oil emulsions.

Sample C was the only mixture that had residual solid material on the surface, which required more aggressive mixing and shear to build the fluid. Separation of the oil phase on the top of the sample was evident in Samples A and C after rolling, so these two were removed from further consideration.

Water-wetting behavior is an important indicator of how well the oil remains dispersed in the system and whether sufficient emulsifier remains to wet additional surfaces. This function was assessed by a simple method of observation when lowering the heating cups from the viscometer after measuring the rheology. A fully water-wet system, for example, leaves no residue on the rotating sleeve and in the heating cup once the fluid is poured out. Further, when cleaning the equipment, a rinse with fresh water would leave no traces of oil sheen, confirming that the oil was completely emulsified.

Samples B, D, and E were mixed at the same emulsifier concentration and compared. Surfactant B left an oily residue and was the poorest performer in this subset. Sample D left no residue at all, while Sample E showed some oil sheen after rinsing the surfaces with fresh water. **Figure 2** shows some of the surface character. Distinct water droplets are visible in the jar (above the mud) in Sample D, while there is a filmy appearance above Sample E.

Multiple reasons exist for why a DEWBM system that retains healthy water-wet properties and a tight oil-in-water emulsion is desired:

- Water-based fluids products function best when available water is present, so this enables the use of regular WBM viscosifiers, filtration control, and other additives in the system.
- Increased emulsion stability allows for better re-use and tolerance of contaminants.
- Minimizing or eliminating phase separation allows much better density control.
- Full water-wetting improves cleanup for cementing and surface equipment.
- Free oil presents potential hazards, such as aromatic fumes and a low flash point.

Contamination work was performed to assess the stability of System D to commonly occurring chemicals and minerals that would mix with the fluid in the field. These pilot tests allowed for a preview of the fluid behavior when contacting salt, cement, drill solids, acid gas, and after barite during weight up. Several laboratory barrels of the base DEWBM were prepared; in **Table 5**, Sample 1 shows a stable emulsion achieved and its properties.

Drill solids buildup was simulated by the addition of Rev Dust calcium-bentonite powder. Amounts from 4 to 12% by volume (up to 108 lbm/bbl) caused minor increases in the initial rheology values but did not significantly change the fluid properties after hot rolling overnight at 150°F. The plastic viscosity (PV)/yield point (YP) ratio in this case increased from 3/4 with the base fluid to 10/7 with the highest solids loading (Sample 4). This provided evidence that the new DEWBM would have minimal need for dilution because of increased solids content.

A quantity of 5 lbm/bbl Class H cement was added to Sample 5 and hot rolled. This provided a spike in pH but no change to the rheological properties or emulsion stability. Rock salt was added to help ensure the fluid could carry salt cuttings and avoid dissolution. No changes to the fluid or the rock salt were observed after hot rolling, and the salt was easily screened out from the fluid afterward.

An aging cell was filled with a laboratory barrel of base fluid and pressurized with CO_2. This fluid had a much lower pH after hot rolling but otherwise showed no change in rheological properties. Weight up of the laboratory fluid from 9.4 to 12.0 lbm/gal (with API barite) showed no adverse effects, although additional viscosifiers would likely be needed to provide adequate suspension.

The final phase of development involved using field brine to build the experimental DEWBM. The base formulation with Surfactant D was mixed with several field brines from the Permian Basin area, and the DEWBM showed similar properties as when fresh sodium-chloride brine was used, with no signs of incompatibility (**Table 6**). Final checks included compatibility with the standard corrosion inhibition and sour gas scavengers used in the field.

The final DEWBM formulation contained six primary components: field brine, diesel, Emulsifier D, a viscosifier blend, a filtration control additive, and caustic soda for alkalinity.

Yard Trial

To better understand how the laboratory-tested formulation would behave under field conditions, a yard trial was conducted. A 21 bbl mix of 9.4 lbm/gal DEWBM was prepared in a small mixing tank with brine and diesel, along with the other products in the selected formulation. The batch was circulated and agitated for 2 hours with no foaming issues observed. **Figure 3** shows various samples during mixing, with improvement in the emulsion stability apparent over time.

Afterward, the mix was left static in the tank to observe any signs of phase separation or other issues over a 9 day period. Samples of the mud were taken from the surface, and they showed a gradual decrease in MW from 9.4 to 9.2 lbm/gal, and the oil content increased approximately 4% by volume, although no breakout was observed. All other properties were in line with the laboratory testing, and no foaming issues resulted. Based on the positive results from this yard test, the project was advanced to a field trial.

Field Trial

For the first field trial, a two-well pad was selected in southeast New Mexico. While the drilling rig batch drilled the two surface holes, the DEWBM was premixed in 300 bbl batches using a premix tank and then moved to a storage tank. The field brine and other additives were mixed, and the diesel was added last to target a MW of 9.7 lbm/gal. The mud properties for each batch were checked and observed for stability.

During the drilling of the first intermediate section, the initial ROP was comparable to drilling with brine, actually showing a 6% increase in the depth of cut. The initial pH of the system was kept at 9 through the Red Beds and Salado formations. No bit balling issues were observed while drilling these reactive clays. While drilling the salt formations, long ribbon-like drill cuttings were observed at the shale shakers, indicating the DEWBM was remaining saturated and not dissolving the salt. The pH was then increased to 10 in anticipation of encountering any acid gases.

Because the drilling rate was high (200+ ft/hr), it was crucial to run the finest screens possible (API 170) and both centrifuges to keep the low gravity solids (LGS) as low as possible to help minimize the need for a higher diesel concentration in the DEWBM.

At approximately 5,000 ft, the MW was lowered to 9.3 lbm/gal before entering the Brushy Canyon (low fracture gradient formation), as planned. At approximately 5,600 ft, the well began to experience a minor loss of circulation. Additional diesel was added to the DEWBM to reduce the MW further to 9.1 lbm/gal, and lost circulation sweeps were pumped, which stopped the losses. At 7,000 ft, a trip was performed to replace the mud motor. Before the trip, a fluid caliper was pumped that indicated an approximate 7% hole volume washout.

The new bottomhole assembly (BHA) was tripped back in the hole, and vertical drilling resumed at a MW of 9.2 lbm/gal. After drilling ahead to approximately 7,800 ft, minor lost circulation was encountered; lost circulation material (LCM) was pumped, which stopped the losses. Drilling continued to a depth of 8,358 ft, and casing was run with no issues. Samples were collected while drilling and observed over time, showing a stable emulsion. A two-stage cement operation was conducted with partial returns. **Figure 4** presents tracking for the fluid density, oil content (NAP), and LGS.

The rig skidded to the second well's intermediate section and began drilling with the DEWBM from the first well. The density was kept low (9 to 9.4 lbm/gal) based on losses experienced in the first well. No losses or wellbore stability issues were experienced at the lower MW. The LGS were inadvertently allowed to increase toward the end of the section, resulting in a MW increase. The LGS were reduced and the MW declined back to specification. Several trips were conducted throughout the section because of mud motor issues. Before the last mud motor trip, a caliper sweep was conducted, showing a washout of 7% by volume.

Once the section TD was reached, a three-armed caliper was run. The DEWBM showed a 63% reduction in hole washout through the salt zones and a 23% reduction for the total intermediate section, as compared to wells that utilized alternative types of brine and WBM. Casing was run with no issues, and a two-stage cement operation was performed. The first stage had cement returns to surface, so the differential valve (DV) tool was cancelled. **Figure 5** shows tracking for the fluid density, oil content (NAP), and LGS.

Additional laboratory testing used field samples of the DEWBM to conduct pilot tests with increased brine and diesel dilution, various viscosifiers, and filtration control additives to test the range of customized formulations. **Table 7** shows the base properties of a field sample, along with two pilot tests to reduce the API filtrate. These tests indicated the formula was stable at higher volumes of oil and could be modified for high-viscosity pills/sweeps and lower filtrate by using standard WBM additives.

Conclusions

Overall, the DEWBM system proved to be a significant improvement compared to other mud systems used in the intermediate sections of Permian Basin horizontal wells. The stringent development and testing criteria proved to be of benefit, resulting in no performance issues and ultimately a considerable reduction in well costs.

- Continued use of a three-string versus a four-string casing design.
- Caliper logs showed a reduction in salt zone and intermediate section washouts.
- DEWBM slightly improved drilling rate.
- No issues occurred with hole cleaning.
- No issues experienced with contaminants.
- Dump and dilute was eliminated, resulting in a reduced mud volume requirement.
- Liquid waste disposal amounts were essentially eliminated, resulting in significant cost savings.
- Loss of circulation was significantly reduced through the control of MW using additions of diesel.
- The DEWBM system was able to be reused on subsequent wells.
- The DEWBM system was simple to mix and maintain at the wellsite.

Other important lessons learned during the DEWBM system field trials that were important to its continued success were

- Because MW is controlled with liquid additions, it is imperative to manage mud volume.
- Because the intermediate section is typically a large-diameter borehole (9.875 to 12.25 in.) and the drill rate is fast (200+ ft/hr), it is paramount that the finest shaker screens are run on the primary shakers and supplemental solids control is continuously run, typically two large-diameter bowl centrifuges, to keep up with the reduction of drill solids. If not, more diesel will be necessary to compensate for the increased LGS, thus increasing costs.

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Figures and Tables

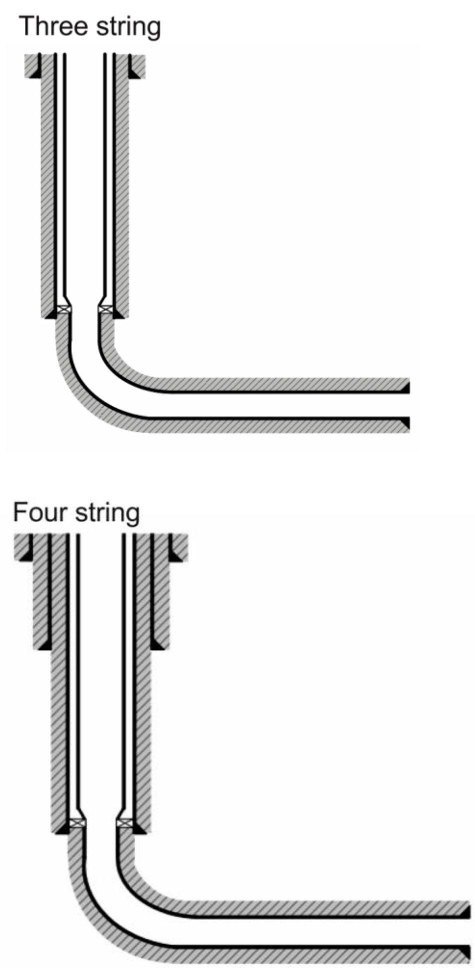

Figure 1. Well profiles.

Figure 2. Samples D and E.

(a) (b) (c)

Figure 3. Yard trial DEWBM samples: after mixing (a) 90 minutes, (b) 75 minutes, and (c) 10 minutes in the tank.

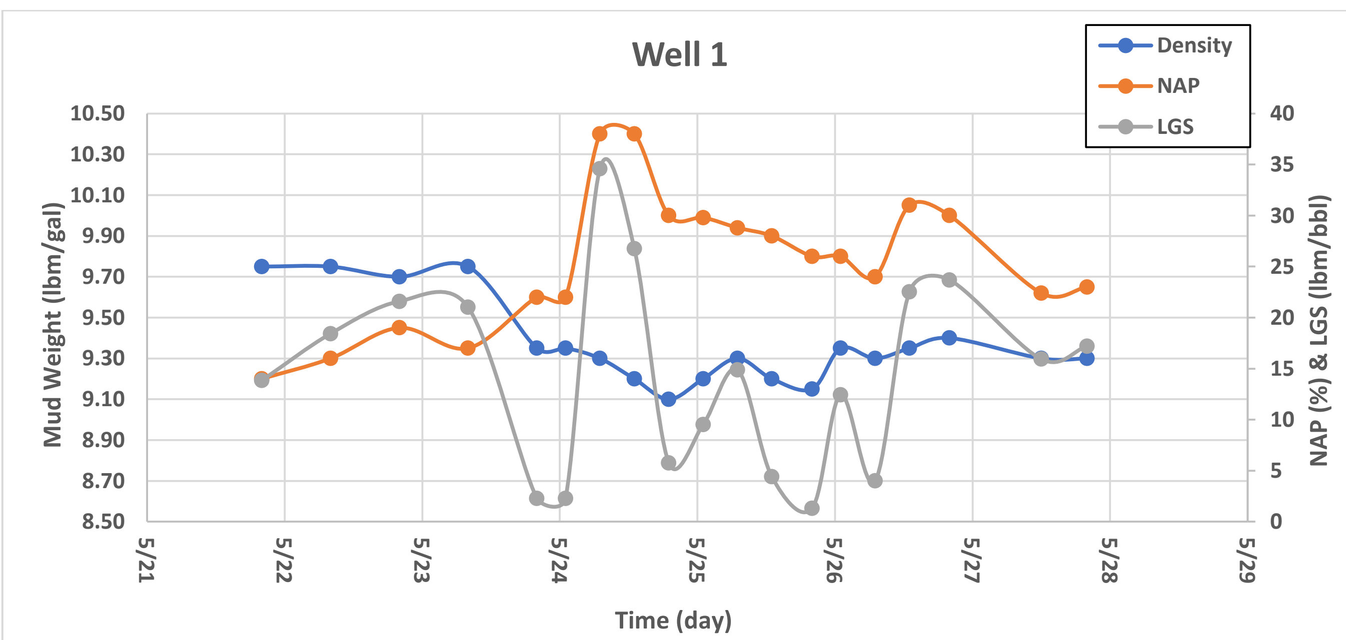

Figure 4. Well 1 DEWBM properties.

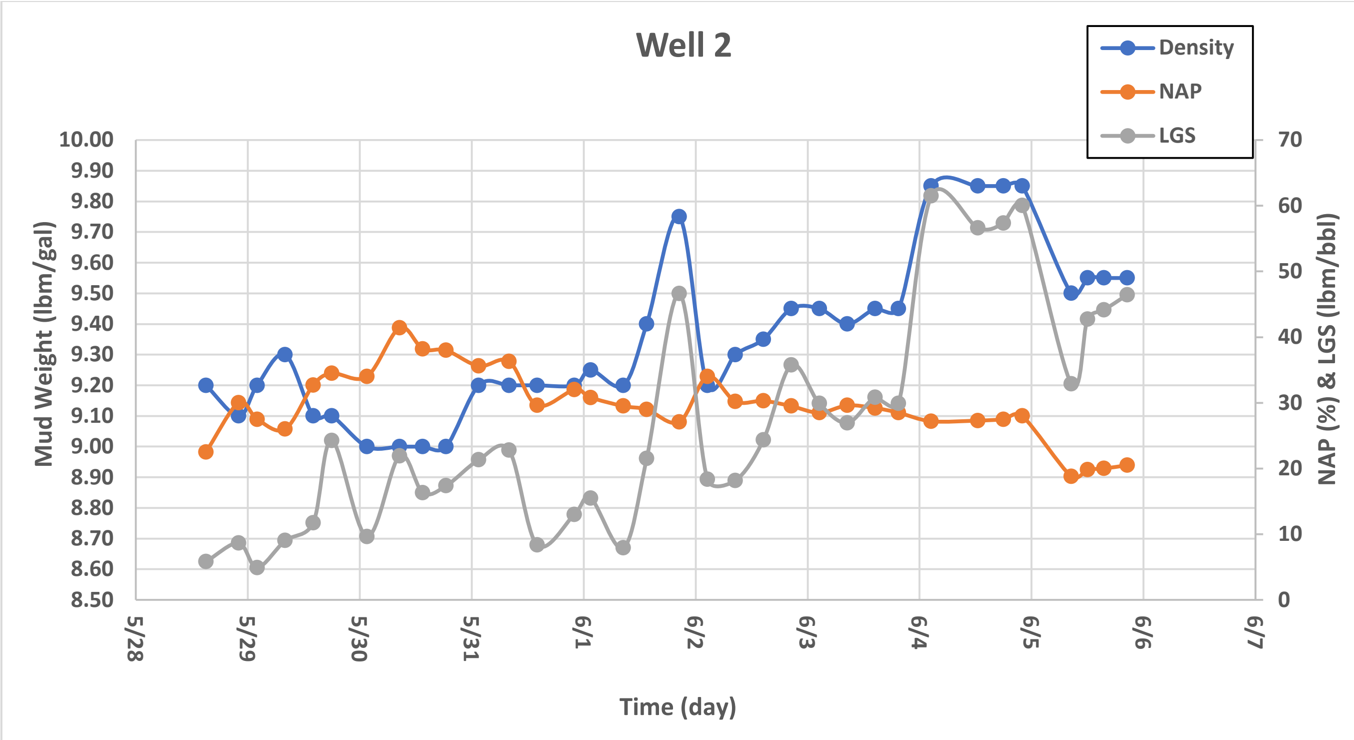

Figure 5. Well 2 DEWBM properties.

Table 1. Permian Basin Formations

System	Series/Stage	Midland Basin	Delaware Basin
Permian	Ochoan	Dewey Lake	Dewey Lake
		Rustler	Rustler
		Salado	Salado
	Guadalupian	Tansill	Delaware Mountain Group
		Yates	Bell Canyon
		Seven Rivers	Cherry Canyon
		Queen	Brushy Canyon
		Graysburg	
		San Andres	
		San Angelo	
	Leonardian	Leonard	Bone Spring
		Spraberry	
		Dean	
	Wolfcampian	Wolfcamp	Wolfcamp

Table 2. Target Properties

Emulsion stability	Adequate for long periods of time at ambient conditions and for at least 24 hours at 150 to 200°F; no rapid phase separation
Density	9.4 lbm/gal, lower values as a stretch goal (~9.0 lbm/gal)
Rheology profile	Minimal PV/YP, hole cleaning is mostly achieved from fluid velocity
Filtration control	API filtrate of 10 or greater to aid in ROP
Foaming tendency	Minimal to zero; easily controllable with existing defoamer products

Table 3. Emulsifier Characteristics

Surfactant	A	B	C	D	E
Charge type	Nonionic	Anionic	Cationic	Nonionic	Nonionic
Form	Liquid	Liquid blend	Solid	Liquid blend	Liquid
Water soluble?	Yes	Yes	No	Partial	Yes

Table 4. Emulsifier Performance Observations

Surfactant	A	B	C	D	E
Surface residue	No	No	Yes	No	No
High shear needed?	No	No	Yes	No	No
Emulsion stability	Poor	Fair	Fair	Good	Good
Water-wetting	N/A	Poor	Poor	Good	Fair

Table 5. DEWBM Laboratory Formulations Including Contamination Testing

Sample	1	2	3	4	5	6	7	8
Initial DEWBM density (lbm/gal)	9.4							
Base mud chlorides (mg/L)	181,000							
Initial diesel volume (bbl)	0.20							
Laboratory-mixed fluid (laboratory bbl)	1	1	1	1	1	1	1	1
Simulated drill solids (volume %)	0	4	6	12				
Class H cement (lbm/bbl)					5			
Salt (lbm/bbl)						20		
Pressure in psi, CO_2							300	
Barite (g), increase to 12 lbm/gal								166
Hot rolled at 150°F (hours)	16	16	16	16	16	16	16	16
pH	8.2	8.3	8.1	8.0	10.7	8.2	5.6	8.9
Rheology Measurements at 120°F								
PV (cp)	3	3	6	10	4	4	4	6
YP (lbm/100 ft^2)	4	8	6	7	3	4	4	6
Note: All samples remained water-wet. Insoluble salt was visible in Sample 6.								

Table 6. DEWBM Laboratory Formulation with Field Brine (Chlorides at 183,000 mg/L)

Sample	**9**	**10**
Field brine (bbl)	0.78	
Diesel (bbl)	0.20	
DEWBM density (lbm/gal)	9.4	
Static aged at 150°F (hours)	0	48
pH	9.6	9.0
Rheology Measurements at 120°F		
PV (cp)	8	8
YP (lbm/100 ft^2)	15	13
6-rpm Reading	5	5
API filtrate (cc/30 min)	2.9	2.7
Note: Zero oil separation following heat aging.		

Table 7. DEWBM Field Sample Pilot Testing

Sample	**11**	**12**	**13**
9.3+ lbm/gal Field DEWBM (laboratory bbl)	1	1	1
LGS (%)	3.7		
Oil (%)	34		
Chlorides (mg/L)	182,000		
Premium starch w/biocide (lbm/bbl)		4	
Modified starch (lbm/bbl)			4
Rheology Measurements at 120°F			
PV (cp)	9	16	23
YP (lbm/100 ft^2)	6	14	18
6-rpm Reading	4	8	6
API filtrate (cc/30 min)	50.0	6.9	2.5
pH	8.8	8.7	8.3