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Next Generation Flat Rheology Fluid Unlocks a New Dimension in Drilling Operations

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Abstract

Flat rheology invert emulsion drilling fluids were developed in the early 2000s to overcome the complex operational issues in drilling deepwater wells, which continue to become more challenging with increasing complexity in well design and the need for improved efficiencies.

Now a newly patented innovative chemistry takes this concept a step further allowing the drilling fluid to run the cold temperature rheological profile and gel structure thinner than the high temperature profile giving a reverse rheological effect, thereby significantly reducing pressures in the well.

This reverse rheology drilling fluids system also delivers the low shear rate viscosity (LSRV) and reduced sag potential required for the intricate intervals drilled in deepwater and other complex wells. This innovative single top to bottom fluid solution ensures enhanced rate of penetration (ROP), trouble-free pipe running and high-integrity casing and liner cementing while minimizing losses.

This new technology has been successfully deployed in the field delivering lower breaking circulation pressures, and reduced equivalent circulating density (ECD), eliminating mud losses while drilling, running casing/liner, and cementing while representing significant cost savings and reduced NPT.

This submission discusses the lab development and field deployment of this reverse rheology system as the next generation of drilling fluid for complex well applications.

Introduction

It is projected that E&P companies will need to add 43 million barrels per day of new crude from new projects to meet increasing demand by 2035. It is expected that offshore production will account for about 30 percent of this new crude production, with roughly half of the total offshore volume coming from deepwater and ultra-deepwater resources (McKinsey & Company 2019).

The technological challenges associated with drilling exploration wells in deep- and ultra-deepwater offshore basins are highly complex (McLean et al. 2010). The key operational issues faced on the more challenging deepwater fields are generally related to narrow pore/fracture pressure gradient margins, cuttings transport and maintaining a sufficient rheological profile for effective hole cleaning, lost circulation to highly permeable or fractured formations and most importantly safety concerns related to effective well control and protection of the environment.

As wells become increasingly more challenging, with increased complexity in design, innovative new drilling fluid solutions have been developed to help mitigate the technical risk of drilling these wells and to further improve drilling efficiencies.

Synthetic fluids have become the invert emulsion drilling fluid of choice for most deepwater operations. Flat rheology drilling fluids have been successfully used for deepwater drilling due to their outstanding performance in providing excellent hole cleaning, temperature-independent rheological profile, good barite sag control and good ECD control (Friedheim et al. 2012). In these fluids, the flat rheological profile is conventionally achieved by using correct combinations of emulsifier, wetting agent, rheological modifiers and supplementary viscosity modifiers.

While it is also known that several physical properties affect the low temperature rheological properties of synthetic drilling fluid, the main ones being the kinematic viscosity of the base fluid, brine phase volume fraction and the particle size distribution of the weight material, these factors are often not easy to manipulate due to environmental and operational constraints. With the introduction of a new patented chemistry the flat rheology concept can be taken a step further, allowing the drilling fluid to run the cold temperature rheological profile and gel structure thinner than the high temperature profile. Extensive hydraulic modelling in drilling and casing/liner run scenarios with varying hydraulic diameters and drilling parameters, and downhole and surface field data from complex deepwater wells proved the significant reduction in well pressures with the reverse rheological effect.

Reverse Rheology drilling fluid concept

In deepwater, the cold temperatures in the riser elevate the viscosities and gel strengths of most standard invert emulsion drilling fluids. Many conventional synthetic based fluids attempt to address this effect in cold water by simply lowering the viscosity. This invariably means the overall rheological profile of the fluid will decrease in proportion with lowering temperatures. Therefore, simply lowering the viscosity does not take into consideration other performance issues common to most drilling operations, such as hole cleaning, barite sag, cuttings suspension and transport.

The newly developed reverse rheology fluid system allows a consistent 150°F rheological properties to be maintained sufficiently so that the hole cleaning and suspension characteristics of the fluid are maintained, while allowing a lower 40°F set of rheological properties to be achieved to reduce pressure spikes throughout the well and minimize the effect of fluid viscosity variations on ECD. This reverse rheological profile eliminates the adverse effects of cold temperature on both viscosity and gel strengths and provides enhanced solid suspension characteristics at elevated temperature.

The improved carrying capacity of the fluid at higher temperatures also minimizes undesirable ECD increases caused by mud weight fluctuations related to improper hole cleaning or barite sag. A further benefit of improved cuttings transport is reduced operational times required to clean up the well prior to running casing strings (Vickers et al. 2020).

Drilling fluid design

It has long been understood that the interfacial chemistry of the dispersed phases, particularly the solids and emulsion droplets can have an influence on barite sag in invert emulsion drilling fluids. The type and concentration of the emulsifier and wetting agent can affect emulsion stability and the wettability of the solids components, and also that these factors can have a significant effect on the dynamic stability of the system and on sag (Bern et al. 1996), (Saasen, 2002), (Albertsen et al. 2004).

Anionic surfactants are known in the industry to reduce significantly the viscosity of organophilic clays systems with the effect of shifting phase behavior from shear thinning with a yield stress more towards Newtonian, which can, in extreme cases, result in increased barite sag.

A comprehensive research program was undertaken to investigate the likely root causes of barite sag in conventional synthetic based muds (SBM) and determine optimal treatment to mitigate sag problems without excessively increasing fluid rheological properties. The new fluid utilizes a unique anionic surfactant chemistry which provides the unique reverse rheological characteristics of the new fluids design.

Micronized weighting agents are becoming more widely accepted as a key component in deepwater drilling fluids to mitigate dynamic sag following the introduction of ultra-micronized barite technology in 2005. Micronized barite is used as the principal weighting agent for the high-performance invert emulsion fluid (HPIEF) system. The development of a new emulsifier and wetting agent chemistries, and a novel conditioning agent provides improved emulsion stability and low viscosity which are more difficult to control with conventional additives due to the increased surface area to volume ratio of the micronized weighting material.

Incorporation of new polymeric additives, rheological modifiers and proprietary suspension additives can be used to further improve the sag resistance of the new HPIEF for more technically demanding applications.

Table 1 shows a conventional SBM formulation with 77/23 internal olefin to water ratio and which is weighted to 14.5 lbm/gal with micronized barite. 2.1% volume API clay is included in the formulation to simulate drill solids. The benefits of the reverse rheological profile can be clearly seen in the new fluid design, shown in Table 2, which can be achieved by the addition of novel surfactant chemistry and rheological modifiers. The reverse rheological effect is more clearly shown in Figure 1, where the 40°F - 100°F rheological properties of the fluid can be reduced without significantly impacting the low shear viscosity of the fluid at higher temperatures.

The ability to convert a conventional SBM to a low viscosity HPIEF is easily achievable with the new chemistry, with zero or minimal dilution. This was the principal selection criterium during the concept validation phase of the project.

Hydraulics modelling was performed to quantify the effect of rheological properties on predicted ECD values. The first simulation scenario was the circulation of a production liner in a deepwater well with a challenging well geometry and small hydraulic diameter and total depth (TD) greater than 25000 ft. The baseline rheological properties used were of the conventional fluid showed in Table 2. The simulation outputs showed a reduction of 0.1 lbm/gal in the ECD at TD for the HPIEF, and 53% in the breaking circulation pressure. See Figures 2 and 3. The second modelling simulated the drilling of a 12 ¼-in section at 25300 ft in a deepwater well. In this case, the aim was to determine the benefit of the reverse rheological profile in large hydraulic diameters. The following drilling parameters were used for the simulation, ROP: 150 ft/h, surface RPM: 150, and total flow: 1380 gpm. The HTHP rheological data for the conventional fluid and HPIEF was the same as in the liner run simulation. The HPIEF reduced the projected ECD by 0.09 lbm/gal, and by 23% the breaking circulation pressure. See Figures 4 and 5.

Transitional rheology

Reversing the rheological profile was not the only technical goal in the new HPIEF design. The development of this new fluid technology also aimed to create a top-to-bottom solution for drilling deepwater wells with complex geometries, which means mitigating a variety of risks such as hole cleaning issues in the upper sections, delicate ECD management in the lower sections with narrow drilling window, emulsion stability and sag resistance over prolonged static periods under high BHST. Table 3 shows a summary of the technical challenges addressed for the HPIEF.

Field Case 1

Following the successful field introduction of the system, the HPIEF was selected to drill a type-S deepwater well with a 60° maximum inclination in the Gulf of Mexico. The KPIs for the well included improved ECD management, reduced mud losses to the formation and no barite sag under both dynamic and static conditions.

The field results were compared with an offset well drilled from the same platform and with similar geometry and drilling fluid parameters. In total, 16,000 ft were drilled in three sections with recorded ROPs of greater than 200 ft/h with BHCT exceeding 200°F. The KPIs described above, along with the ones set for the emulsion stability (ES), and HTHP fluid loss, were met.

There were three static periods when the HPIEF remained static for up to five days at BHST of greater than 210°F. The maximum mud weight variation measured at the gumbo box was 0.2 lbm/gal. The MW variations for the three periods are summarized in Table 4.

For the analysis of the dynamic and static sag performance, three HPIEF field samples were later analyzed in the onshore Client Support Laboratory (CSL). The Viscometer Sag Shoe Test (VSST) results showed a variation of no greater than 0.2 lbm/gal, and the MW variation after seven days was 0.22 lbm/gal for the 15 lbm/gal HPIEF sample. The ΔMW was determined from the difference in MW of the bottom mud layer (25% of the fluid volume) minus the nominal MW. The aging of the fluid was done in a 500-ml stainless steel aging cell at the test temperature and pressurizing the cell with N_2 just to avoid evaporation. The results are summarized in Figure 6.

In addition to standard VSST measurements, the sag flow loop equipment (Bern et al. 1996) (Troncoso et al. 2018) was used on a post job analysis to evaluate the sag behavior under extended dynamic conditions for a 15.2 lbm/gal HPIEF sample. Figure 7. The ΔMW recorded at the end of the zero-rotation period and low shear rates was 0.07 lbm/gal. Additional flow loop tests were conducted with an ultra-micronized fluid and two conventional SBMs samples. The HPIEF with the novel rheological profile showed a similar ΔMW compared to the ultra-micronized system and lower than the conventional SBMs. The sag flow loop results for the HPIEF are shown in Table 5.

Field Case 2

The HPIEF was used to drill the 18-1/8- and 12-1/4-in sections of a deepwater well in the Gulf of Mexico with a wellbore inclination of greater than 30°. The main KPI set for the HPIEF was to achieve a lower ECD while providing the same or better hole cleaning capabilities than the incumbent SBM fluid which displayed a more conventional rheological profile. The ECD reduction evaluation of the HPIEF, and its novel reverse approach concept, was done by selecting as baseline an offset well with comparable well geometry, and drilled with similar parameters i.e. flow rate, ROP, BHCT, RPM and mud density. Figure 8 shows the results of the ECD measurements from the MWD tool. The delta between ECD and ESD Δ(ECD-ESD) was 0.05-0.1 lbm/gal lower for the well drilled with the HPIEF compared to the offset well drilled with the incumbent SBM fluid.

The thorough engineering of the fluid in the field encompassed the adjustment of the product concentrations, particularly the new emulsifier and conditioning agents, and the rheological and barite suspension additives, allowing the fluid to display a pronounced lower HSRV and reverse LSRV profile which translated into the Δ(ECD-ESD) reduction. It must be noted here that the reduction in the rheological properties did not compromise the sag-resistance feature of the HPIEF. In this respect, the new fluid design with micronized weighting agent (d50 ≤ 9 µm), and a precise suspension package concentration, delivered an improved dynamic and static sag performance compared to the conventional SBM.

The sag potential was lab tested in the field and in the onshore CSL through VSST checks, in-house sag flow loop testing, and static sag tests for up to 7 days at the BHST. The ECD management and sag performance directly demonstrated the hole cleaning capabilities of the HPIEF at even higher ROPs than those seen in the offset well, as the post evaluation showed.

Another way to gauge the emulsion stability in the field was through HTHP and ES testing. The HPIEF showed stable and low HTHP fluid loss coupled with ES readings greater than 400 volts in both sections.

The reverse rheological profile also helped in the reduction of the breaking circulation pressures, and the elimination of mud losses throughout the entire project operation: drilling, casing and production liner runs, and cementing compared with the offset well. The casing and production liners were run to the programmed depth and within the allotted time.

Conclusions

The HPIEF maintains a stable emulsion with the newly patented innovative chemistry which eliminates wellbore instability issues.

The reverse rheological effect is achieved by reducing the 40°F-100°F rheological properties of the fluid without impacting the low shear viscosity of the fluid at higher temperatures.

The newly developed HPIEF with reverse rheological profile reduces downhole pressures and minimizes dynamic and static sag.

The exceptional rheological profile of the HPIEF provides lower ECD values and ensures good hole cleaning, which minimizes downhole losses especially for the wells with narrow hydraulic windows.

Significantly reduced break-circulation pressures are seen with the HPIEF, which can also minimize the potential of pressure induced fractures, hence further mitigate the risk of downhole losses.

Acknowledgments

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Nomenclature

CSL=Client Support Laboratory
BHCT= Bottomhole Circulating Temperature
BHST= Bottomhole Static Temperature
ROP= Rate of Penetration
RPM= Revolutions per Minute

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Table 1. Conventional SBM formulation

Component	**lbm/bbl**
Internal olefin (synthetic)	139
Emulsifier	12
Wetting agent	1
Organoclay	1
Proprietary suspension additive	0 - 6
Lime	5
25% CaCl2 Brine	77
Synthetic polymer	0 - 1
Rheological modifier	1.5
Micronized barite	340
Clay (simulated drill solids)	20

Table 2. HPIEF properties

	Conventional Fluid			**1st Generation HPIEF**			**2nd Generation HPIEF**		
Heat Aging Temp, °F	280			280			280		
Heat Aging, h	16			16			16		
Static/Rolling	D			D			D		
Mud Weight, lbm/gal	14.50			14.50			14.50		
Rheology Temp, °F	**40**	**100**	**150**	**40**	**100**	**150**	**40**	**100**	**150**
R600, °VG	397	142	90	253	120	79	192	85	61
R300, °VG	210	81	55	140	66	46	104	52	38
R200, °VG	151	60	41	98	47	35	72	38	29
R100, °VG	86	37	27	54	28	22	40	23	19
R6, °VG	21	13	12	8	7	8	7	8	11
R3, °VG	19	12	11	7	6	8	5	8	10
PV, cP	187	61	35	113	54	33	88	33	23
YP, lbf/100 ft²	23	20	20	27	12	13	16	19	15
LSYP, lbf/100 ft²	17	11	10	6	5	8	3	8	9
10-sec Gel, lbf/100 ft²	21	18	20	7	8	12	7	10	16
10-min Gel, lbf/100 ft²	77	44	31	23	33	38	21	26	29
VSST at 150°F							0.11		
Sag ΔMW, lbm/gal (280°F/15kpsi)							0.5		

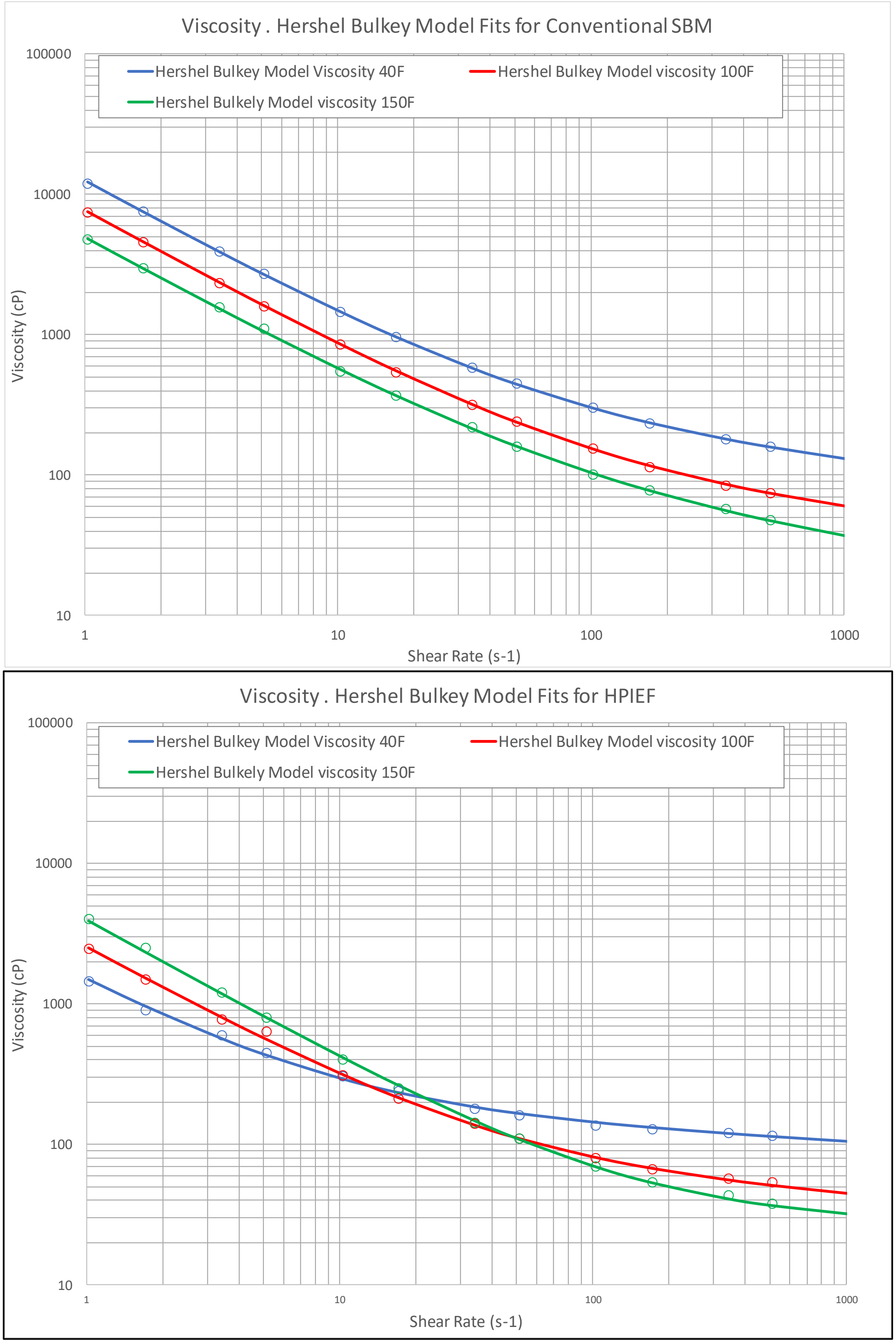
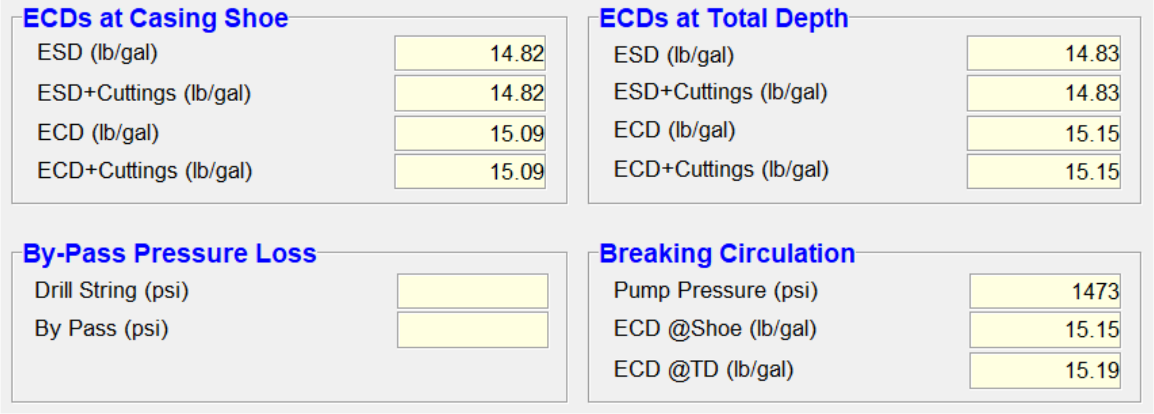


Figure 1 Rheograms showing the reverse rheological effect



ECDs at Casing Shoe

ESD (lb/gal)	14.82
ESD+Cuttings (lb/gal)	14.82
ECD (lb/gal)	15.09
ECD+Cuttings (lb/gal)	15.09

ECDs at Total Depth

ESD (lb/gal)	14.83
ESD+Cuttings (lb/gal)	14.83
ECD (lb/gal)	15.15
ECD+Cuttings (lb/gal)	15.15

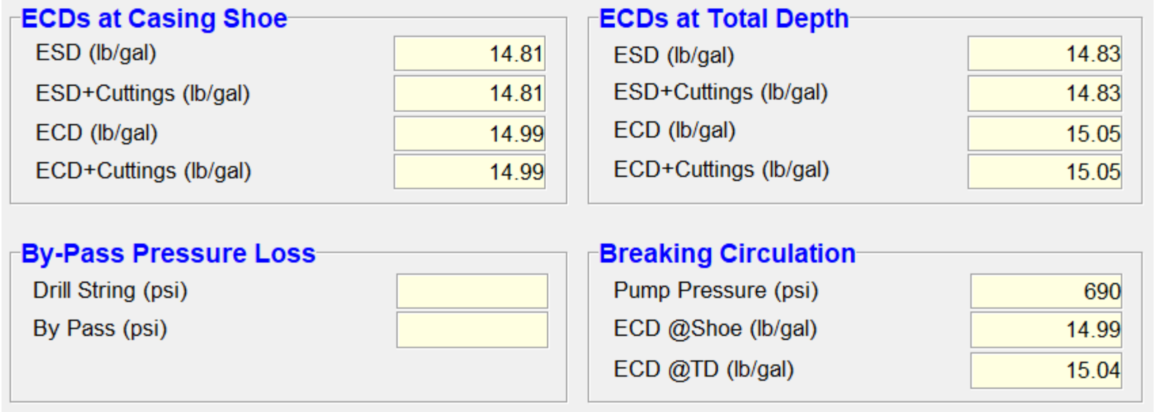
By-Pass Pressure Loss

Drill String (psi)	
By Pass (psi)	

Breaking Circulation

Pump Pressure (psi)	1473
ECD @Shoe (lb/gal)	15.15
ECD @TD (lb/gal)	15.19

Figure 2. Hydraulic simulation for liner circulation with conventional SBM



ECDs at Casing Shoe

ESD (lb/gal)	14.81
ESD+Cuttings (lb/gal)	14.81
ECD (lb/gal)	14.99
ECD+Cuttings (lb/gal)	14.99

ECDs at Total Depth

ESD (lb/gal)	14.83
ESD+Cuttings (lb/gal)	14.83
ECD (lb/gal)	15.05
ECD+Cuttings (lb/gal)	15.05

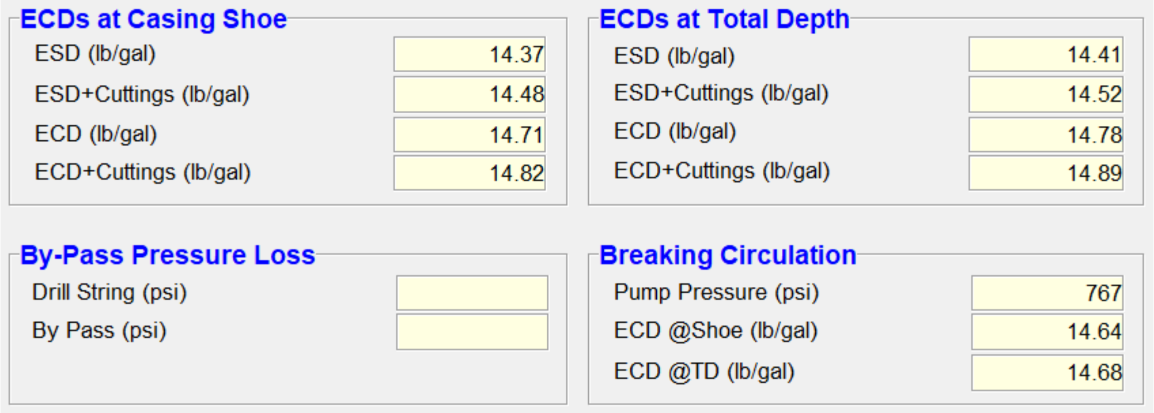
By-Pass Pressure Loss

Drill String (psi)	
By Pass (psi)	

Breaking Circulation

Pump Pressure (psi)	690
ECD @Shoe (lb/gal)	14.99
ECD @TD (lb/gal)	15.04

Figure 3. Hydraulic simulation for liner circulation with HPIEF



ECDs at Casing Shoe

ESD (lb/gal)	14.37
ESD+Cuttings (lb/gal)	14.48
ECD (lb/gal)	14.71
ECD+Cuttings (lb/gal)	14.82

ECDs at Total Depth

ESD (lb/gal)	14.41
ESD+Cuttings (lb/gal)	14.52
ECD (lb/gal)	14.78
ECD+Cuttings (lb/gal)	14.89

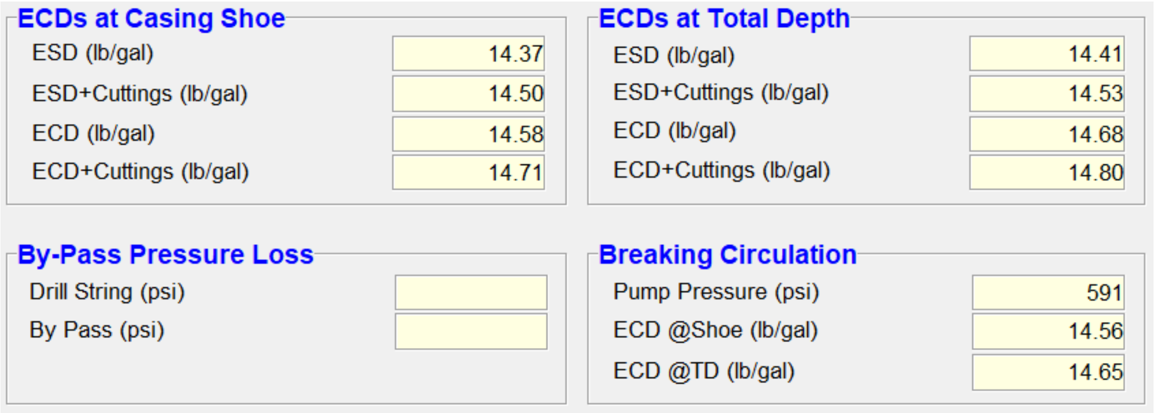
By-Pass Pressure Loss

Drill String (psi)	
By Pass (psi)	

Breaking Circulation

Pump Pressure (psi)	767
ECD @Shoe (lb/gal)	14.64
ECD @TD (lb/gal)	14.68

Figure 4. Hydraulic simulation, drilling 12 1/4-in section with conventional SBM



ECDs at Casing Shoe

ESD (lb/gal)	14.37
ESD+Cuttings (lb/gal)	14.50
ECD (lb/gal)	14.58
ECD+Cuttings (lb/gal)	14.71

ECDs at Total Depth

ESD (lb/gal)	14.41
ESD+Cuttings (lb/gal)	14.53
ECD (lb/gal)	14.68
ECD+Cuttings (lb/gal)	14.80

By-Pass Pressure Loss

Drill String (psi)	
By Pass (psi)	

Breaking Circulation

Pump Pressure (psi)	591
ECD @Shoe (lb/gal)	14.56
ECD @TD (lb/gal)	14.65

Figure 5. Hydraulic simulation, drilling 12 1/4-in section with HPIEF

Table 3. HPIEF features vs Conventional SBM

	Conventional SBM	HPIEF
Reverse rheological profile	⬜	🟩
Acceptable viscosity profile under Temp/Press	🟩	🟩
Dynamic sag	⬜	🟩
Static sag	⬜	🟩
Thermal stability	🟩	🟩
Hole cleaning	🟩	🟩
Low ECD, low break circulation pressures	⬜	🟩
Mud properties relaxation	⬜	🟩
Cement spacer contamination	🟩	🟩

Table 4. MW variation after static periods (at gumbo box)

Static Period, days	**Nominal MW, lbm/gal**	**Maximum MW After Static Period, lbm/gal**	**MW variation, lbm/gal**
6	12.5	12.6	0.1
3	13.8	13.9	0.1
5	14.7	14.9	0.2

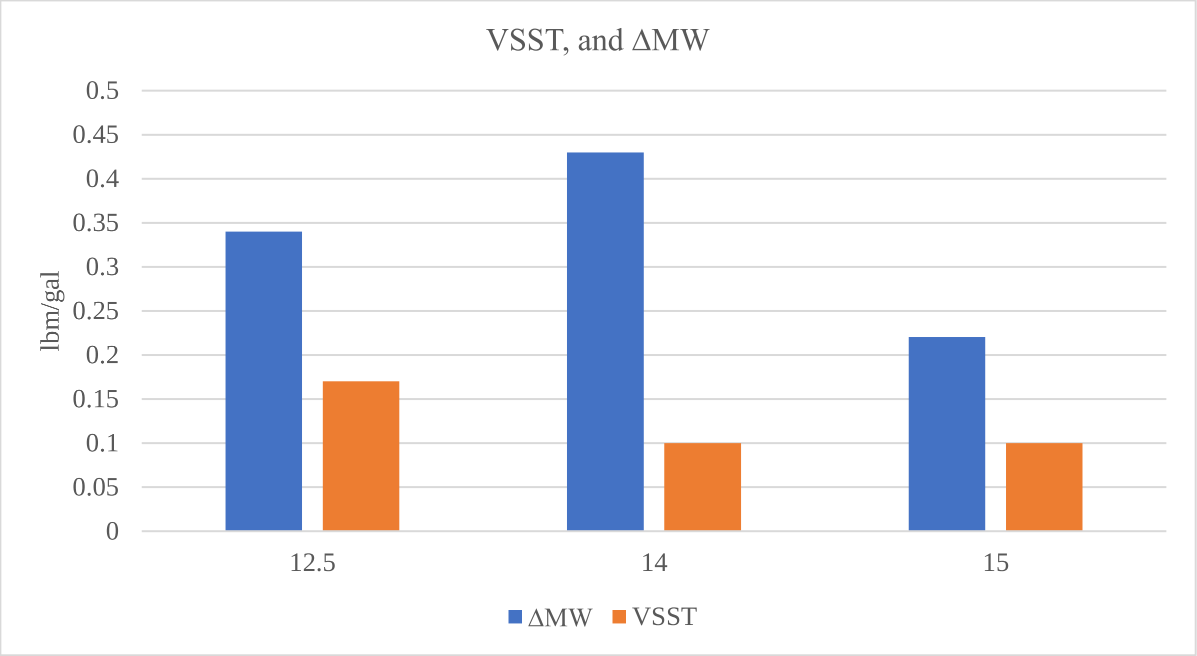


Figure 6. Dynamic sag (VSST) and Static Sag (ΔMW) after 7 days static aging at 210°F

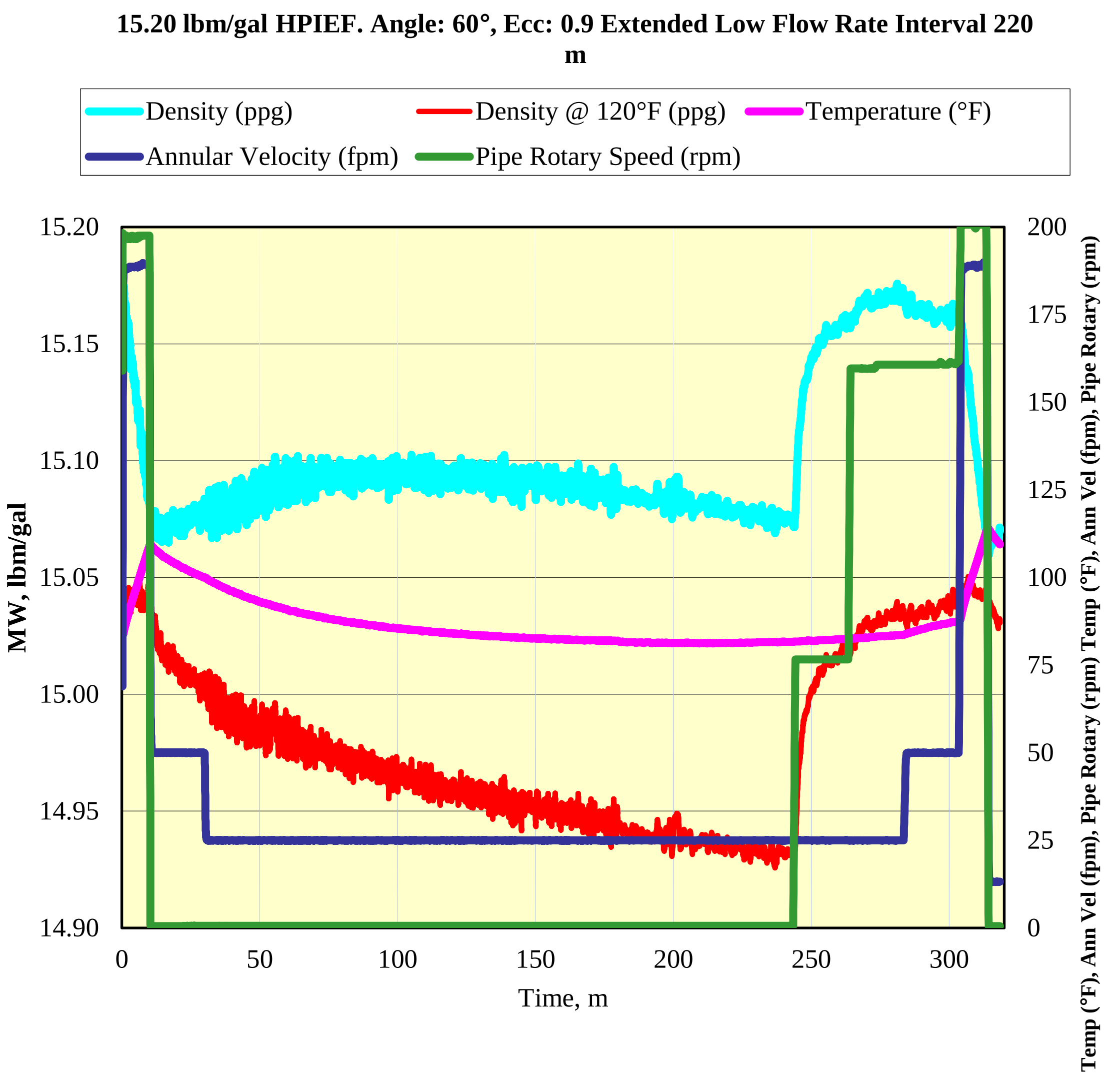


Figure 7. Extended sag flow loop results for HPIEF

Table 5. Sag flow loop results for conventional SBM, Ultra-micronized system, and HPIEF

Fluid	Initial MW, lbm/gal	Final MW, lbm/gal	ΔMW, lbm/gal
Conventional SBM # 1	15.40	15.30	0.10
Conventional SBM # 2	15.97	15.84	0.13
Ultra-micronized system	15.17	15.09	0.08
HPIEF	15.00	14.93	0.07

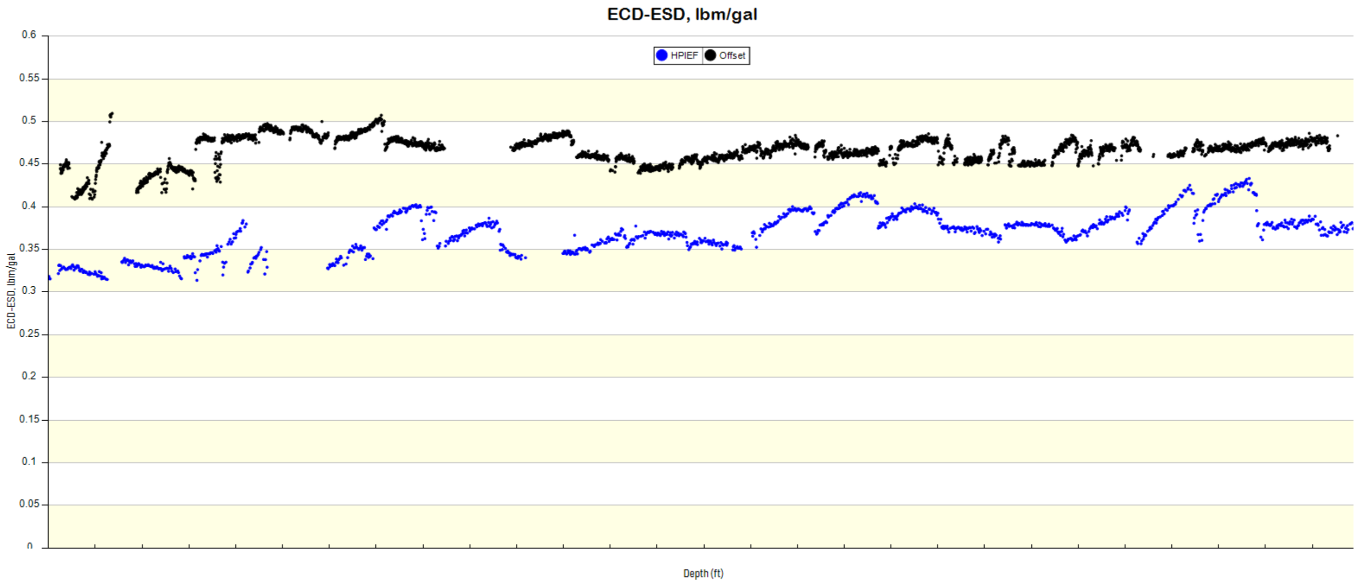


Figure 8. Δ(ECD-ESD) comparison between offset well and HPIEF