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Improved OBM System for North Dakota- Field Study

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Abstract

The intermediate section (vertical and curve) of typical wells in North Dakota have been drilled with oil-based mud for years. The primary reason is to minimize shale instability and salt zone washout. Other challenges in the intermediate section of the well are minimizing lost circulation while drilling and while running and cementing casing.

A recent improvement in the oil-based mud formulation has resulted in decreased ECD and surge pressures by maintaining a significantly lower PV/YP profile throughout the drilling process. Drill cutting’s lifting is primarily accomplished by existing annular velocity while improved suspension during connections is achieved through non-progressive gel structure, which minimizes surge pressure when circulation is initiated. Rheological properties in the clay free oil-based system are managed by relatively small additions of rheological modifiers that yield in one circulation or less, as compared to the significantly longer yield times of organophilic clay. Once intermediate casing point is reached, the system rheology can be rapidly lowered as the casing is filled, allowing for additional reduction in the ECD profile when circulating mud through the casing through the problematic shale zones. The reduced rheology profile leads to less induced fracturing and destabilization of the shale. This has been evidenced by a 50% reduction in oil-based mud losses on casing runs and cementing.

Overall, the improvements in the oil-based mud formulation have resulted in a mud system that is easily and quickly modifiable with rheology modifiers and base fluid dilution, thus managing the above challenges present while drilling in North Dakota.

Introduction

Saturated Salt mud was the dominant drilling fluid of choice utilized on much of the early wells drilled in North Dakota’s Williston Basin. This mud system minimized salt solubilization in the basin’s multiple salt bearing formations and provided some degree of formation inhibition. It did not however, provide complete protection from salt formation washout though, as fluid saturated at surface was not saturated at the elevated downhole temperatures. This allowed for salt dissolution and led to eventual casing failures in many instances (Rike et al. 1986). This system relied primarily on the addition of starch for fluid loss control and was susceptible to bacterial degradation. These wells were almost exclusively vertical wells with minimal shale exposure in the lower portions of the wells.

Over time, invert emulsion Conventional Oil-Based Muds (COBM) replaced the Saturated Salt systems and remained the preferred drilling fluid throughout the basin for the next several decades. A well-constructed OBM with an all-oil external phase and an osmotically balanced internal water phase dramatically reduced dissolution of the salt formations and led to drastically extended casing life (Stash et al. 1988). COBM also resulted in improved Rate of Penetration (ROP), decreased Non-Productive Time (NPT) and was relatively easily maintained (Leaper et al. 2006). The typical composition of COBM is displayed in **Table 1**:

Table 1- Typical Composition of Conventional OBM Utilized in the Williston Basin

Distillate	80% of Liquid Phase
Produced Brine	20% of Liquid Phase
Primary Emulsifier	2- 4 PPB
Wetting Agent	0.25- 1 PPB
Secondary Emulsifier	4- 6 PPB
Organophilic Clay	8- 10 PPB
Hydrated Lime	2- 4 PPB
Shale Stabilizer	1.5- 2 PPB
API Barite	9.5- 11.0 PPG

COBM losses to formation became a serious consideration to the overall fluid cost of the well with Distillate comprising 80% of the liquid phase of the fluid. Distillate total cost typically equals or exceeds the sum of all other mud additives used for fluid building and maintenance. Detailed accounting of mud losses and loss categorization gained importance as a tool for controlling overall fluid cost.

The advent of horizontal drilling in the basin led to increased critical angle shale exposure in the build portion of the intermediate interval where the COBM has typically been utilized. While early COBM muds were often maintained as loose, or relaxed emulsions, the additional shale exposure required tighter HTHP filtrate control and the addition of shale stabilizer. The increased shale exposure also led to increased mud density to maintain shale stability. In some instances, mud density required to maintain shale stability while drilling led to ballooning in the shale zones. This was often intensified by increased casing surge and ECD pressures in the significantly reduced annular hydraulic diameter of the intermediate casing versus the well bore diameter. This often led to increased instances of sloughing shale and bridging on intermediate casing runs, or in more extreme instances, stuck casing from pack-off.

While the COBM managed to eliminate many of the formation issues of the past, it became apparent that a fluid with an improved approach to rheology and ECD pressure management was required. An approach that would better manage whole mud losses and ensure successful intermediate casing operations with minimal NPT.

Low-Pressure-Impact Oil-Based Mud

A recently developed Low-Pressure-Impact Oil-Based Mud (LPIOBM), marketed as DELTA-DRILL™, was chosen to meet the challenges presented. The goals set forth for this fluid were:

- A decreased ECD profile throughout drilling, casing, and cementing operations in the intermediate well interval.
- Provide adequate solids suspension when the fluid is static in the well bore and during storage between wells.
- Provide shale stabilization.
- Reduce whole mud losses to the formation during drilling, casing, and cementing operations.
- Easily maintained by rig personnel with the "drive-by" service platform preferred by Williston Basin operators.
- Compatible with standard emulsifier packages and shale stabilizers already in use.
- Exhibit temperature stability of -40°F to ≤ 250°F.
- Cost effective and enhance overall operational goals.

The fluid trials and all data represented in this paper are based upon the same field applications for both COBM and LPIOBM. The typical composition of the LPIOBM is displayed in **Table 2**:

Table 2- Composition of Low-Pressure-Impact OBM

Distillate	60%- 75% of Liquid Phase
Produced Brine	40%- 25% of Liquid Phase
Primary Emulsifier	2- 4 PPB
Secondary Emulsifier	4- 6 PPB
Primary Polymeric Viscosifier	1- 2 PPB
Rheology Modifier	0.25- 1 PPB
Hydrated Lime	2- 4 PPB
HTHP Filtrate Control Additive	1- 2 PPB
Shale Stabilizer	1.5- 2 PPB
API Barite	9.5- 11.0 PPG

Rheology Profiles

Decreasing the ECD profile by modifying only the fluid rheology required lowering the PV/YP ratio. Standard annular velocities in the Williston Basin range between 300- 400 FPM (**Figure 1**) across the drill pipe in the intermediate open hole interval. This velocity is generally considered more than sufficient for cuttings lifting and Barite suspension in dynamic circulation conditions (Grantham at al. 1986).

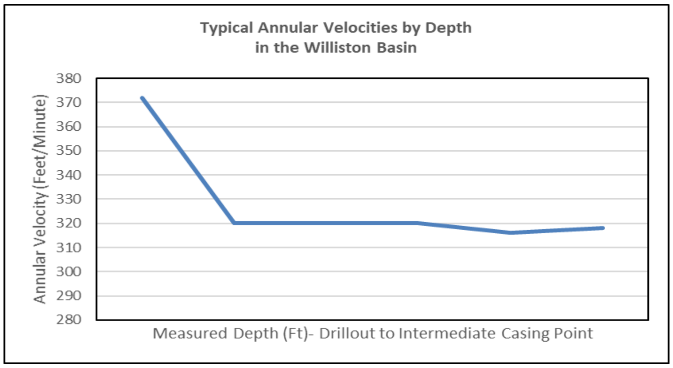

Figure 1- Typical Annular Velocities

Thus, it was theorized that a "thinner and flatter" rheological profile was a viable option in this basin. This left Barite and cuttings suspension in static conditions as the key objective. A rapid set/easy break 10 Second/10 Minute Gel Strength was targeted for achieving this goal.

The COBM previously in use was dependent on 8- 10 PPB of Organophilic Clay as the sole viscosifier (**Table 1)**. Maintaining sufficient Gel Strengths for solids suspension when the fluid was static typically corresponded with an undesired increase in the PV and/or the YP (Grantham et al. 1986). This increase in PV/YP ratio led to undesirable increases in ECD and surge pressures in the intermediate interval during drilling and casing operations.

The LPIOBM fluid utilizes a polyamide resin as the Primary Polymeric Viscosifier. This polymer viscosifier is fast acting, independent of temperature or shear rate for activation, and does not require the addition of Organophilic Clay to attain YP. Gel Strengths are primarily attained through the addition of a low temperature activated fatty acid alcohol derivative Rheology Modifier.

Conventional theory has long held that a YP of 1- 2 times the hole size is considered optimal for good hole cleaning when utilizing mud weights in the 9.0- 12.0 PPG range (Kulkarni et al. 2014). Decreasing the YP in COBM also decreased the Gel Strengths, as the two properties are codependent on the Organophilic Clay viscosifier. The Primary Polymeric Viscosifier used in the LPIOBM controls the YP of the fluid independently of the Gel Strengths. This allows for decreased YP while maintaining sufficient Gel Strength for solids suspension. A YP target of 5- 8 LBS/100 FT^2 was trialed on the initial three test wells. There was no indication of fill on connections, trips, or casing runs at the decreased YPs. Based upon the success of the trials the YP target was decreased to 3- 5 LBS/100 FT^2 on subsequent wells **(Figure 2)**. The represented measurements relating to rheology are based upon in field measurements utilizing an OFITE Model 900 Viscometer.

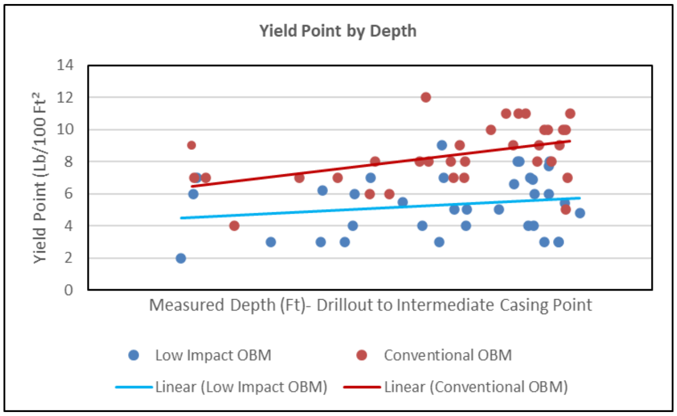

Figure 2- Yield Point by Depth

PV decreased on wells utilizing LPIOBM as compared to wells utilizing COBM (**Figure 3)**. This was seen as a function of both the lower YP and decreased Low Gravity Solids (LGS) content of the LPIOBM. The PV decrease at intermediate casing point averaged slightly over 10% reduction. In some cases, the PV decreased by as much as 45% as compared to COBM wells PV data. While the overall average decrease seen is less than that observed in the corresponding YP, it is theorized that this is due in part to an increased water fraction in the Oil/Water Ratio. The Oil/Water Ratio of the water tolerant LPIOBM field trial wells were intentionally maintained between 65/35 and 75/25 as compared to an 80/20 to 85/15 on the wells utilizing COBM.

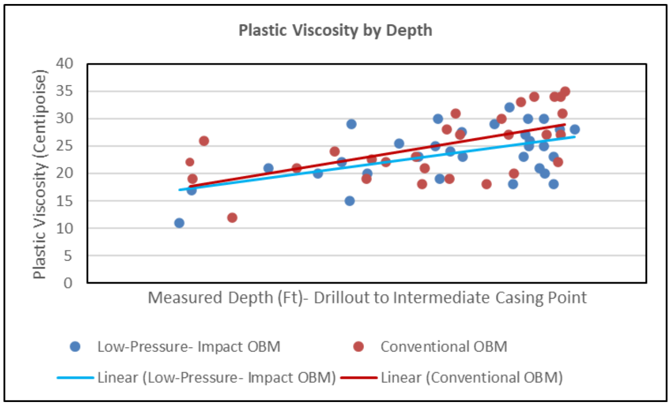

Figure 3- Plastic Viscosity

Cuttings suspension during static conditions was accomplished via increased Gel Strengths. An alcohol derivative Rheology Modifier was utilized to attain desired Gel Strengths with minimal effect on the PV/YP ratio. The 10 Second Gel Strength was targeted at 8- 10 DR (**Figure 4**) and the 10 Minute Gel Strength was targeted at 12- 15 DR (**Figure 5**).

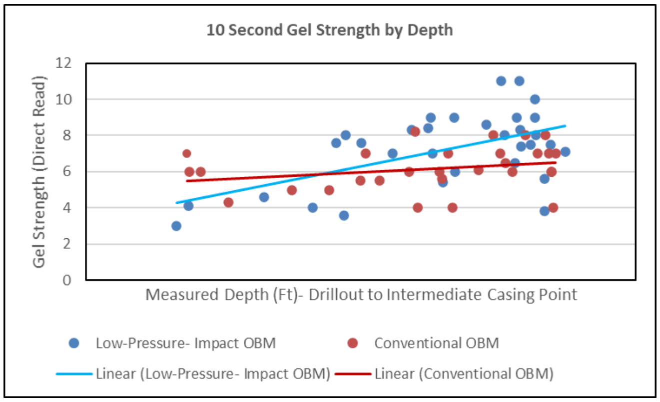

Figure 4- 10 Second Gel Strengths

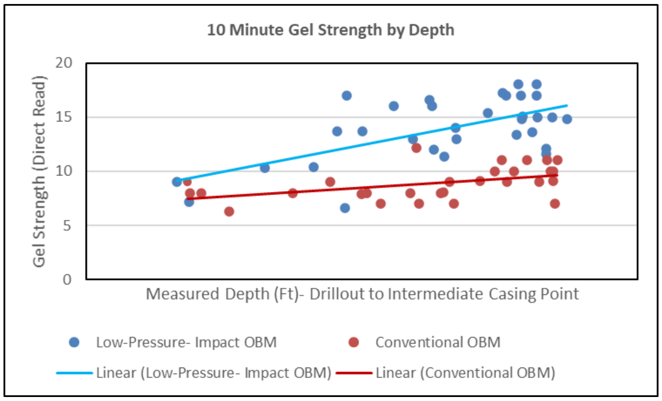

Figure 5- 10 Minute Gel Strengths

The Gel Strengths notated for the LPIOBM are fragile in nature, requiring little flow energy to break. No pressure spikes were noted upon resuming circulation after connections and/or trips.

Barite Sag

Viscometer Sag Shoe Test (VSST) was performed on a representative sampling of fluids from wells utilizing LPIOBM. The testing was performed with a sag shoe insert at 120°F for 30 minutes with a viscometer sleeve rotation of 100 RPM. **Table 3** represents the VSST results. VSST variations below 0.5 PPG are considered to exhibit a low tendency for sag potential (Smith et al. 2019).

Table 3- VSST Results

	Sample 1	**Sample 2**	**Sample 3**	**Sample 4**
MW	10.1	10.4	10.8	10.5
YP	3.8	4.6	6.8	5.3
10 Sec. Gel	8.9	9.4	12.7	10.6
10 Min. Gel	16.8	15.0	18.4	16.4
VSST Δ	0.15	0.23	0.18	0.21

The VSST results corroborate with no solids settling, or fill, noted on connections, trips, or while running casing on the wells utilizing LPIOBM.

ECD and Surge Pressure Profiles

ECDs were calculated for both COBM and LPIOBM wells. The consistency k and flow index n parameters used in the calculations relied upon Herschel- Bulkley multi-point modeling. The ECD results are represented in **Figure 6**.

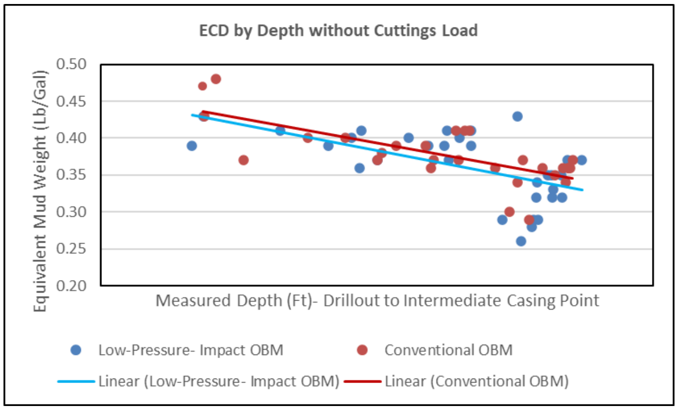

Figure 6- Drilling ECDs

A reduction in average ECD was noted across the entire depth spectrum from surface casing drill-out to intermediate casing point (ICP). The decrease in ECDs correlates with the lowered PV/YP profiles notated in **Figures 2** and **3.** A decrease in the drilling ECD of up to 15% was noted on multiple wells at ICP.

Casing surge pressures were calculated for both fluids at ICP. These calculations are based upon a normalized mud weight, depth, and well/casing geometry. Rheology values displayed were chosen from two representative wells in the field study. Data input used for the calculations is displayed in **Table 4.**

Table 4- Casing ECD and Surge Calculation Inputs

	COBM	LPIOBM
Depth	**11,686’**	**11,686’**
Hole OD	**8.75”**	**8.75”**
Casing OD	**7.0”**	**7.0”**
MW	**10.5 PPG**	**10.5 PPG**
600 RPM	**81**	**39**
300 RPM	**46**	**21**
200 RPM	**33**	**14**
100 RPM	**21**	**8**
6 RPM	**7**	**2**
3 RPM	**6**	**1.6**
10 SEC	**7**	**8.9**
10 MIN	**11**	**15.8**

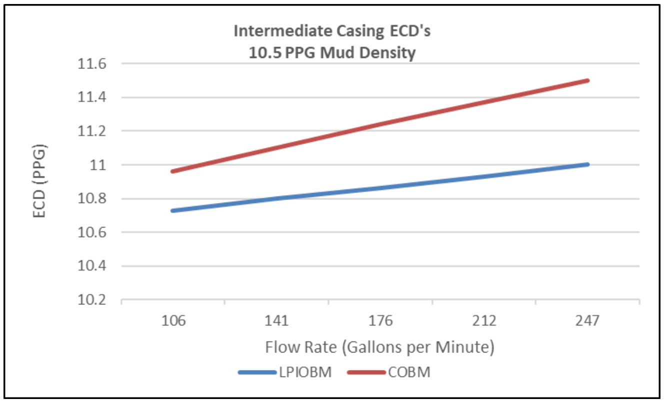

Figure 7- Casing ECD Pressures

The calculated ECD pressures displayed in **Figure 7** represent comparable ECD’s at variable flow rates based upon these rheology inputs. The surge pressures displayed in **Figure 8** correspond to varied casing running speeds.

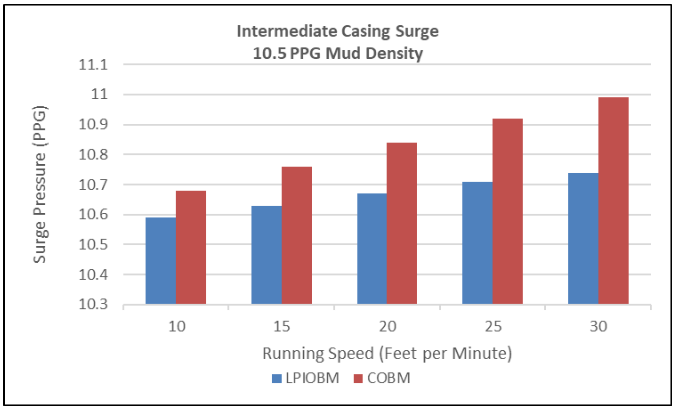

Figure 8- Casing Surge Pressures

The ECD and surge calculations both indicate a significant decline in equivalent pressure generated by the LPIOBM versus the COBM.

Mud Losses to Formation

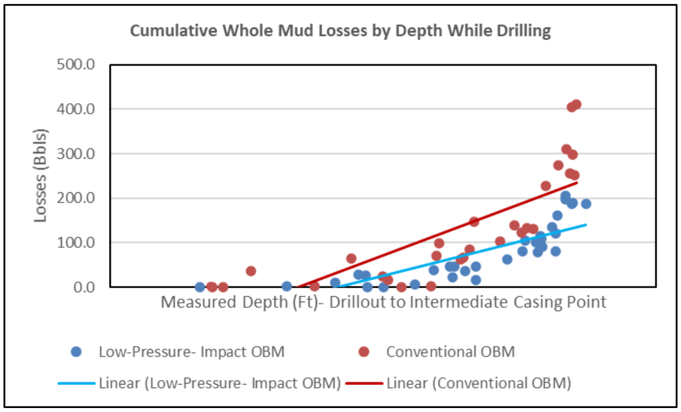

Figure 9- Cumulative Drilling Losses

Cumulative whole mud losses by depth during drilling operations are displayed in **Figure 9**. The LPIOBM consistently displayed lower losses to formation on every well versus COBM. On average the LPIOBM losses during drilling/tripping operations were reduced 28% as compared to offset COBM wells.

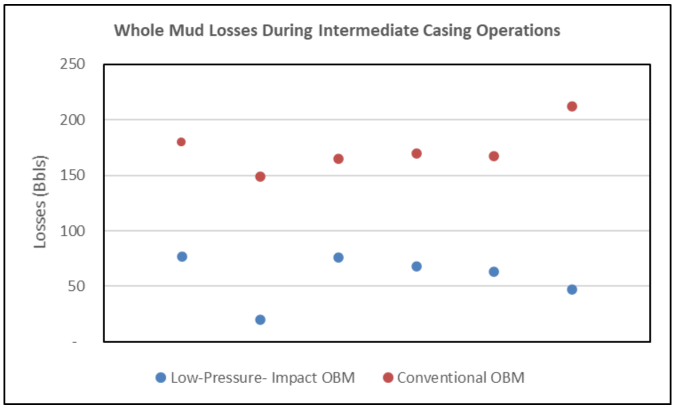

Figure 10- Losses During Casing/Cementing Operations

Whole mud losses to formation during casing and cementing operations, as detailed in **Figure 10,** display significant reduction in the LPIOBM system. On average losses during casing/cementing operations with the LPIOBM were 35% less than those of offset wells utilizing COBM. These values correlate well with the decrease in equivalent pressures demonstrated in **Figures 7** and **8**.

Formation Inhibition

The LPIOBM system runs on the backbone of the previously utilized COBM. As such, the LPIOBM system is compatible with many of the products previously used in COBM (**Tables 1 and 2**) including:

- Conventional emulsifier package
- Alkalinity control agents
- Shale stabilizer products

The LPIOBM includes one additional component in the form of an organic liquid HTHP Filtrate Control Additive (**Table 2).** HTHP filtrate in the Williston Basin is normally maintained loosely until after drilling the salt formations and the lower seepage zone. Desired HTHP filtrate prior to drilling into the lower shale formations is 100% oil and < 6 ML/30 MIN. HTHP filtrate values, as measured at 250°F with 500 PSI differential pressure, for both systems are displayed in **Figure 11**. The liquid HTHP Filtrate Control Additive added an additional level of filtrate control that allowed for easy and effective additions, where needed, instead of pretreating in the upper formations where fluid may be lost to the formation.

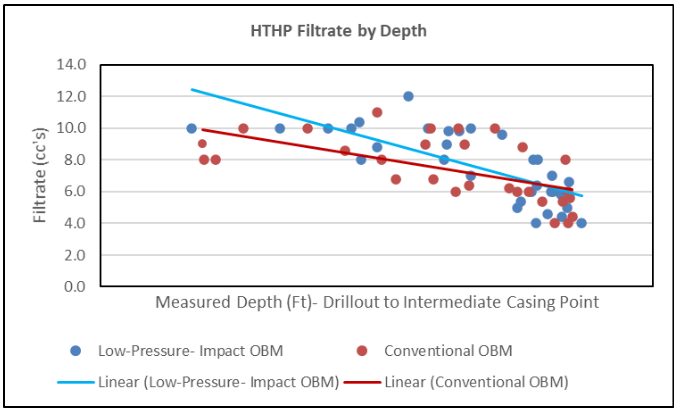

Figure 11- HTHP Fluid Loss

Salt formation inhibition by the LPIOBM remained on par with the performance of the COBM system. Both systems are comparable in that they both contain a produced brine internal phase and an oil external phase. Both systems also contain the same emulsifier package added in similar concentrations. Of note, due to the minimal effect of water additions on rheology, or inhibitive properties, water sweeps that are commonly employed in the basin to reduce tight spots through the salt formations, were able to be incorporated into the active system, rather than diverted at the shale shakers, resulting in negligible effect on mud performance.

Operational and Cost Efficiencies

Product component usage costs for the LPIOBM system averaged 10- 15% greater than product costs for COBM, excluding weight materials. However, the LPIOBM's operational cost savings included:

- A reduction of nearly 20% in base oil/Distillate usage
- Mud loss reduction of 28% during drilling
- Mud loss reduction of 35% while running casing/cementing operations
- Increased ROP
- Decreased NPT
- An overall decrease of 16% in Intermediate Section drilling days (**Figure 12**)

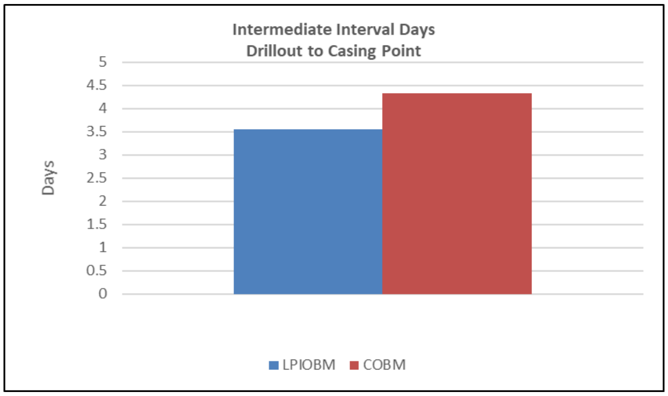

Figure 12- Intermediate Interval Days

Conclusions

1. The DELTA-DRILL™ Low-Pressure-Impact OBM system successfully decreased ECD and surge pressures throughout the intermediate interval drilling, casing, and cementing operations.
2. The increased Gel Strength structure allowed for solids suspension throughout all phases of operations. The fragile nature of the Gel Strengths ensured that pressure spikes were kept to a minimum.
3. LPIOBM provided adequate formation inhibition and stabilization that was equal to or better than provided by the COBM. There was no indication of salt formation dissolution in the field trials.
4. Whole mud losses during drilling, casing, and cementing operations were all reduced. Base oil/Distillate usage was significantly reduced as a result.
5. The LPIOBM was easily maintained by rig personnel with a minimum of supervision. The LPIOBM was in use throughout winter and was successfully stored at below freezing temperatures on multiple occasions.
6. The LPIOBM positively affected overall operations and cost performance through increased ROP and decreased NPT.

Acknowledgments

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Nomenclature

BHA = *Bottomhole assembly*
OBM = *Conventional Oil-Based Mud*
DR =*Direct Read or Dial Reading of Viscometer*
ECD = *Equivalent Circulating Density*
FPM = *Feet per Minute*
FT^2 = *Square Feet*
ICP = *Intermediate Casing Point*
HTHP = *High Temperature High Pressure*
k = *Consistency for the Herschel-Bulkley Model*
LBS = *Pounds*
LGS = *Low Gravity Solids*
LPIOBM = *Low-Pressure-Impact Oil-Based Mud*
ML =*Milliliters*
MW = *Mud Weight*
MIN = *Minutes*
n = *Flow Index for the Herschel-Bulkley Model*
NPT = *Non-Productive Time*
OD = *Outer Diameter*
PPB = *Pounds per Barrel*
PPG = *Pounds per Gallon*
PV = *Plastic Viscosity*
PSI = *Pounds per Square Inch*
ROP = *Rate of Penetration*
RPM = *Rotations per Minute*
OBM = *Oil-Based Mud*
SEC = *Seconds*
VSST = *Viscosity Sag Shoe Testing*
YP = *Yield Point*

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