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Improved Drilling Performance in Extended Horizontals Using Clean Brines in the Williston Basin

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Abstract

The successful drilling of an oil and gas well relies upon the application and maintenance of innovative technology. In order to improve drilling efficiency, all pertinent data needs to be reviewed appropriately and lessons learned need to be drafted and realized. This is particularly important with challenging extended-reach wells. Due to the very low permeability in the target formation, long horizontal laterals are desirable to improve oil recovery and maximize productivity. Long lateral lengths are limited by frictional losses from torque and drag. In this environment, a drilling fluid that is able to maintain low lubricity coefficients is required. In addition, the fluid must be environmentally sound and cost-effective. An underbalanced high-performance brine drilling fluid (HPBDF) was introduced as an alternative to the weighted oil-based fluid required in use.

As expected, different fluids require different strategies. When using a HPBDF, monitoring lubricant concentration and use is best practice. Using field measurements to adjust concentrations, the desired lubricity was achieved and maintained while minimizing lubricant use. Low lubricity coefficients correspond with reduced pipe wear and decreased torque and drag. By planning, monitoring and maintaining the HPBDF, the operator successfully achieved higher rates of penetration (ROP) resulting in shorter drilling times. In this application, low viscosity brines improved wellbore cleaning due to turbulent flow cuttings transport. This reduced time spent on clean up cycles and tripping times as compared to offset wells drilled with oil-based fluids.

The brine density eliminated the need for barite and minimized the solids in the drilling fluid. Suspended drilled solids in the HPBDF can increase abrasion and lead to increased torque and drag and directional tool wear and failures. When solids accumulated in the HPBDF, a dewatering system was used to flocculate the solids and remove them through a centrifuge to produce clean brine. Techniques were improved to provide clear brine while minimizing lubricant loss. For example, application of a high-performance fluid conditioner prevented lubricant loss in the dewatering process.

This paper discusses the use of HPBDF in drilling over 50 wells and the challenges overcome. It also details the equipment used and highlights the comprehensive technique for evaluating lubricity and its

correlation to torque and drag. The resulting performance improvements reduced drilling costs by over 20%.

Introduction

In unconventional horizontal applications, technology improves drilling efficiency and maximizes productivity. In 2014, a Williston Basin operator sought an improved economical solution to drilling performance while minimizing environmental impact. The innovation and cooperation between the service company and operator created improved well performance.

Williston Basin

The Williston Basin is a significant oil and gas basin in North America. It spans from south Saskatchewan, covering the southwest corner of Manitoba, through the northeast corner of Montana. It encompasses most of North Dakota and envelopes northwest South Dakota. See Figure 1. The basin may be divided into six major geological boundaries that are associated with the Phanerozoic eon. Each of these may be coordinated to a respective stratigraphic unit that is then translated to a geological period. Each of these distinct strata has their own sedimentary cycles within themselves. Additionally, the mineral types vary widely within this basin[1,2]. Mineral genres include (but are not limited) carbonates (e.g. sandy or marine), limestone, dolomite, mudstones, sandstones, siltstones, anhydrite, and evaporites. Formation porosities and permeabilities also vary throughout the basin[2].

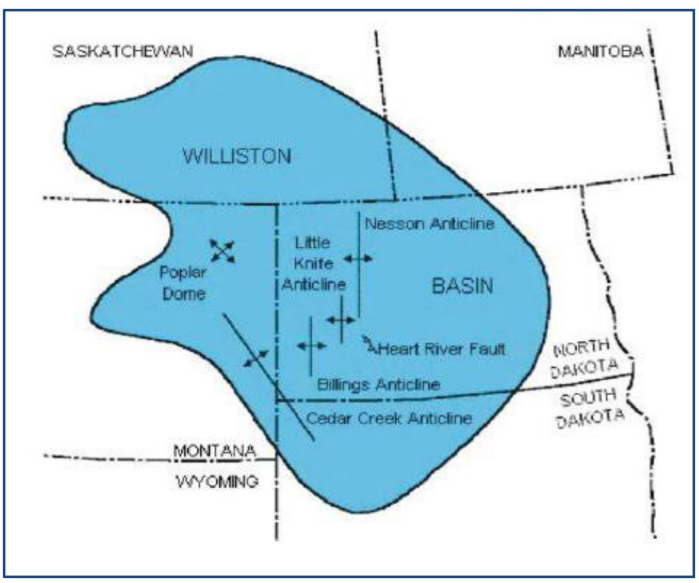

Figure 1—Williston Basin region adapted from Reference 1

Oil and natural gas were discovered in this region in the 1940s. Drilling commenced through the 1950s with one additional well in the 1970s[3]. Production of these wells continued through the 1980s. With the introduction of horizontal drilling, production greatly increased in this region, in particular the Bakken formation. Universally, horizontal lengths increased presenting additional challenges and demands for technological advancements. Although many horizontal drilling challenges encountered in this basin were anticipated, some were unique. This paper discusses the drilling of dolomitic dominated sediments. This discussion also involves drilling through the Charles salt stratum.

Offset Review

The conditions dictated by the formations and well design presented regional operators with many challenges. Historically, operators used oil-based fluids (OBF) for lubricity and ease of use. Although reusable, OBFs have environmental and disposal concerns and as previously mentioned[5] creates costs both at the beginning and end of use.

Oil and gas operators in this region then explored brine-based fluids. Operators retained produced brine-water from previous drilling projects in an effort to reduce waste. However, the produced brines varied in composition and weights. Calcium chloride additions increased density and enhanced inhibition. However, solubility interactions caused these additions to precipitate out NaCl salt[6],[7]. As pointed out by Kemp:

> ″. . .further CaCl2 is added, it will dissolve at the expense of NaCl. The NaCl will precipitate until the invariant point is reached. . .the excess salt solids could clog lines or create other problems. At best, most of the excess salt will be removed by the solids-control equipment, but much of it could remain in the mud systems as fine solids, increasing the mud density and decreasing the penetration rate″[7].

Figure 2, adapted from reference 6, illustrates this relationship. The precipitate causes buildup of salt scale in the drill pipe, BHA, and surface equipment and adversely affects lubricity.

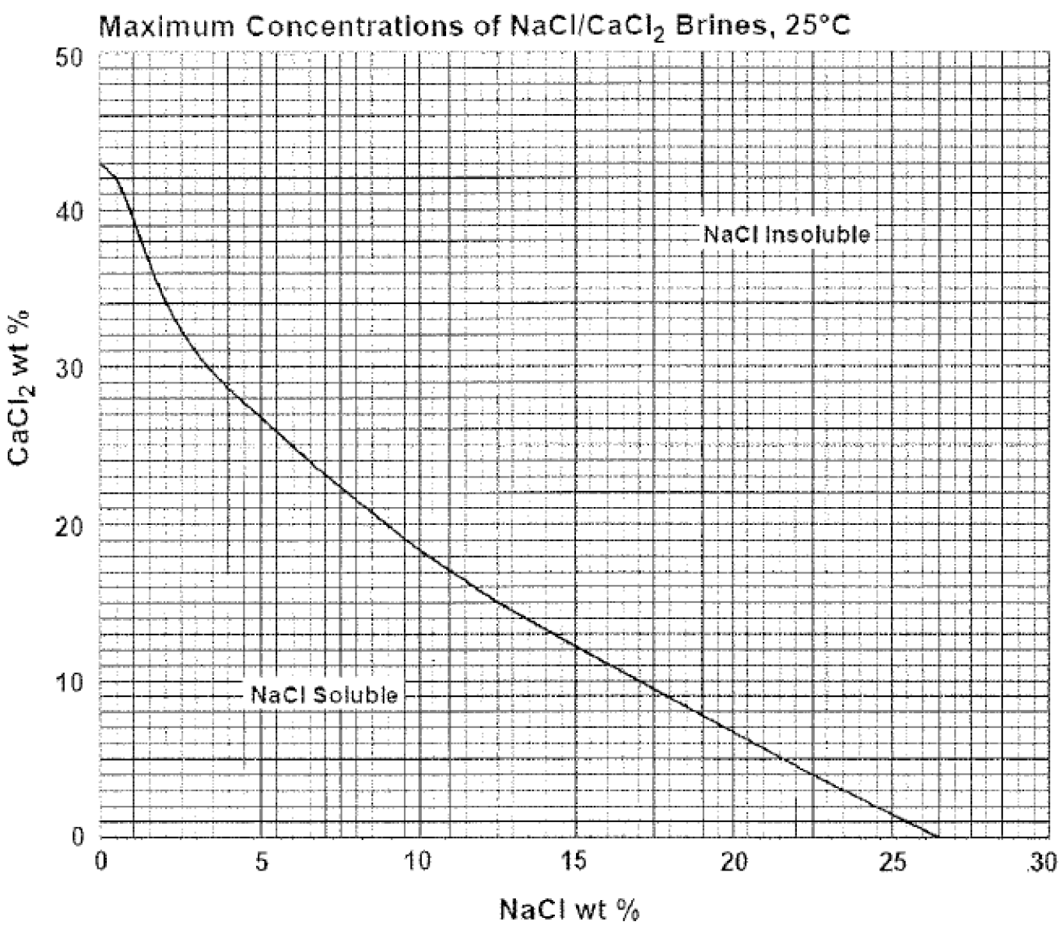

Figure 2—″Figure 1-3 Mutual Solubility Between NaCl and CaCl2 at 25°C″ adapted from reference 6

Lubricity is also adversely affected by common brine management practices including dewatering. The dewatering system provides a clean fluid by flocculating and removing solids with chemical and

mechanical manipulations. Although beneficial for solids reduction, flocculation can have unforeseen ramifications. Lubricants, with surface coating qualities, have an affinity for solids and are often lost with solids removal. Several techniques reduce this loss, thereby lowering the need for lubricant additions and reducing costs while maintaining lubricity requirements.

Well Parameters and Drilling Fluid Design

The industry's shift to drilling long (≥ 10,000 feet) Bakken laterals with inexpensive produced brines was a significant improvement in well performance, primarily due to increased rates of penetration (ROP). Brine is a drilling fluid that provides a baseline inhibition and density. Hole cleaning relies on turbulent flow for cuttings removal. Additionally, brines provide enhanced economics when compared to OBF. They are environmentally responsible though they lack the lubricity to drill long horizontals. High-performing drilling enhancers (HPDE) were introduced to improve lubricity and manage the torque and drag in the laterals. The ideal fluid lubricity coefficient ranges from 0.09-0.13. To aid in concentration and addition management, the fluid's lubricity was consistently monitored on-site through an extreme pressure and lubricity meter. The HPDE was added prior to major events like tripping or casing runs. Due to the abrasive nature of brines, excessive pipe wear along with bit and motor failures were common. As discussed later, the operator switched from produced brine to pure NaCl brines. Oil-based fluids were still used in the intermediate wellbore sections to reduce washouts in the Charles salt sections. Tables 1 & 2 detail the wellbore parameters and the conventional drilling fluid designs.

Table 1—Intermediate Section-OBF

Parameter	Specification
Hole Size (in)	8 3/4″
TVD (ft)	10,500' – 11,500'
Fluid Weight (lb/gal)	10 – 10.5
Plastic Viscosity (cp)	12 to 22
Yield Point (lb/100ft^2)	8 to 12
API Fluid Loss (mL/30 min)	< 15
Water Salinity (ppm)	260,000 – 280,000
ES	>600
Total Solids (%)	<6%
Coefficient of friction	0.09 to 0.13

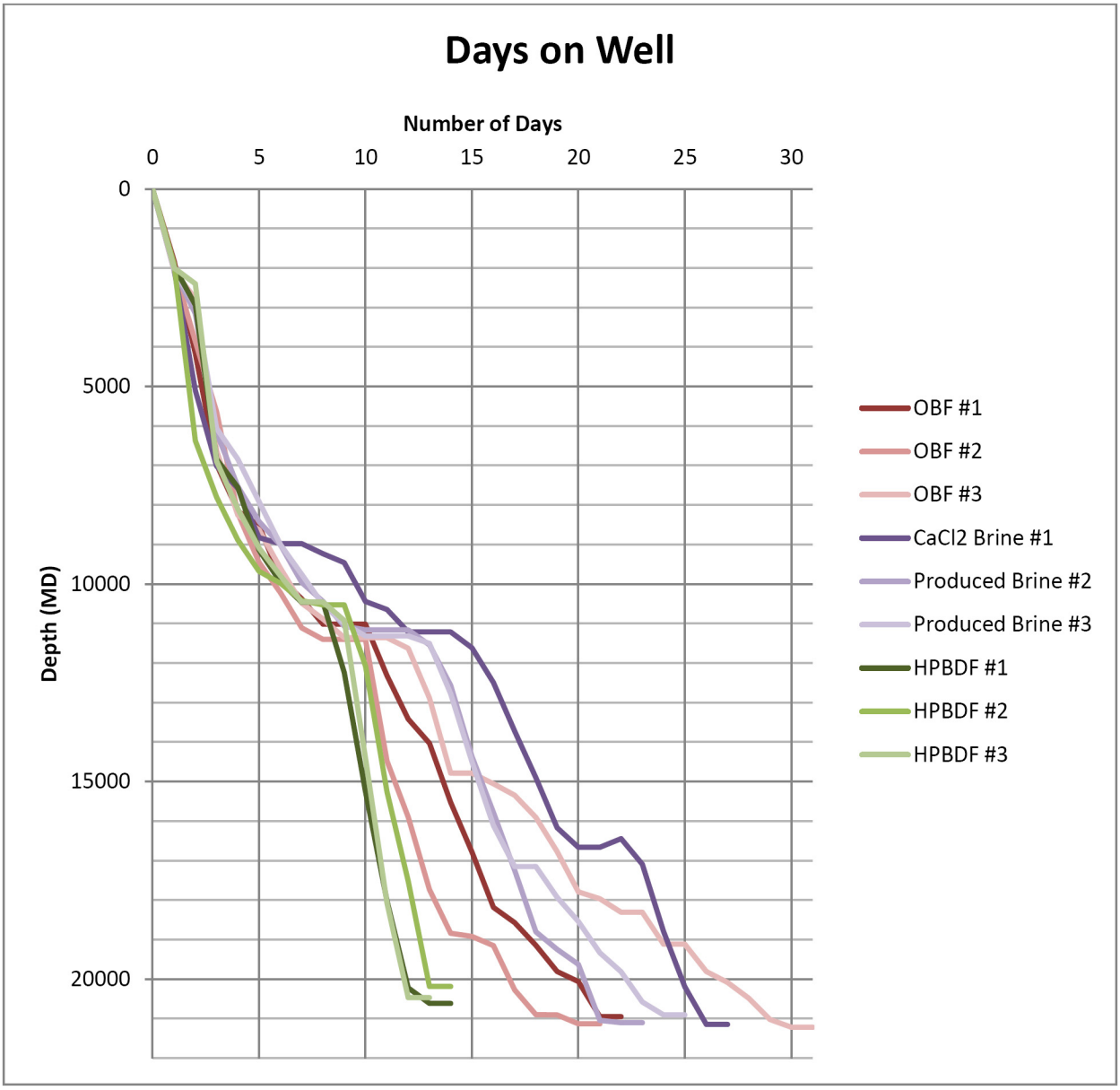

Figure 3—Days on well comparing 3 genres of fluid

Table 2—Production Section-NaCl Brine

Parameter	Specification
Hole Size (in)	6″
Measured Depth (ft)	20,000 – 21,500
Mud Weight (lb/gal)	9.8 – 10.2
Plastic Viscosity (cp)	N/C
Yield Point (lb/100ft^2)	N/C
API Fluid Loss (mL/30 min)	N/C
Water Salinity (ppm)	180,000 – 220,000
pH	8.5 to 9.0
Total Solids (%)	<1
Coefficient of friction	0.08 to 0.13

To build off the previous discussion: in the dewatering process, the lubricant tends to adhere to the solids and is then removed when processed in the solids control equipment. The operator introduced the fluid conditioner application to keep the HPDE in the dewatered effluent. Effluent for the purposes of this paper is defined as the processed fluid after the solids control equipment. This improves efficiency, reduces HPDE additions, and reduces overall well cost. The fluid conditioner also maintains cuttings integrity by keeping the fluid emulsified, especially as it was predicted that the wells might take influxes of crude oil while drilling. Table 3 details the parameters of the HPBDF.

Table 3—High Performance Brine Drilling Fluid

Additive	Function	Approximate Concentration
Xanthan Gum	Viscosity	0.5 – 1 lb/bbl (Sweeps / ECD pills)
Fluid Conditioner	Conditioner	0.25 – 0.75 lb/bbl
High Performance Drilling Enhancer (HPDE)	Friction Control	2-5%
Chlorides (from NaCl)	Inhibition and density	180,000 – 220,000

Overall Well Summaries & Benchmarks

When comparing drilling fluids, the HPBDF outperforms the other two fluid types. Three wells representing each fluid type are graphed in Figure 3 for comparison. The HPBDF (green) total drill time is significantly shorter than the OBF (red) and $CaCl_2$-brine/produced brine (purple) wells.

Figure 4 highlights how the horizontal section decreased from utilizing the HPBDF.

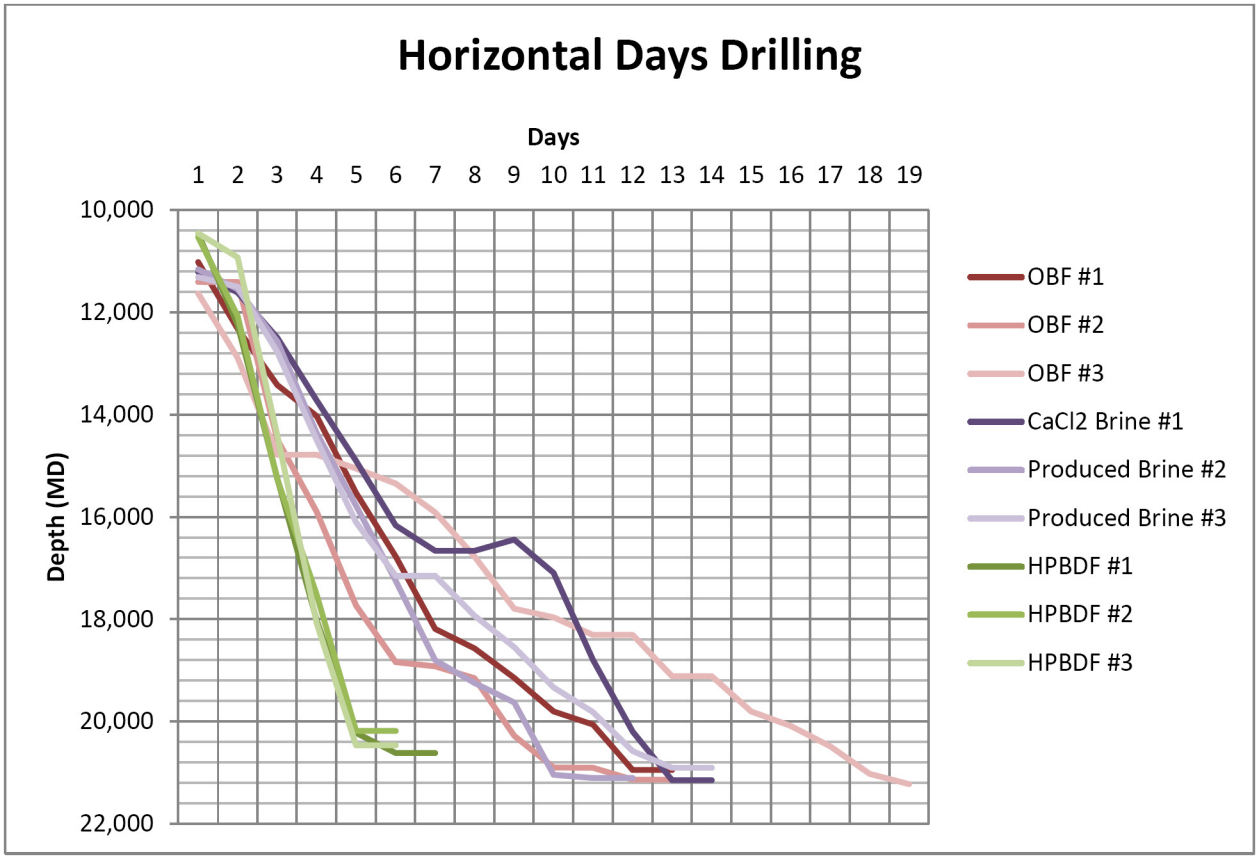

Figure 4—Horizontal Drilling Days

The average ROP illustrates the efficiency of the HPBDF (Figure 5).

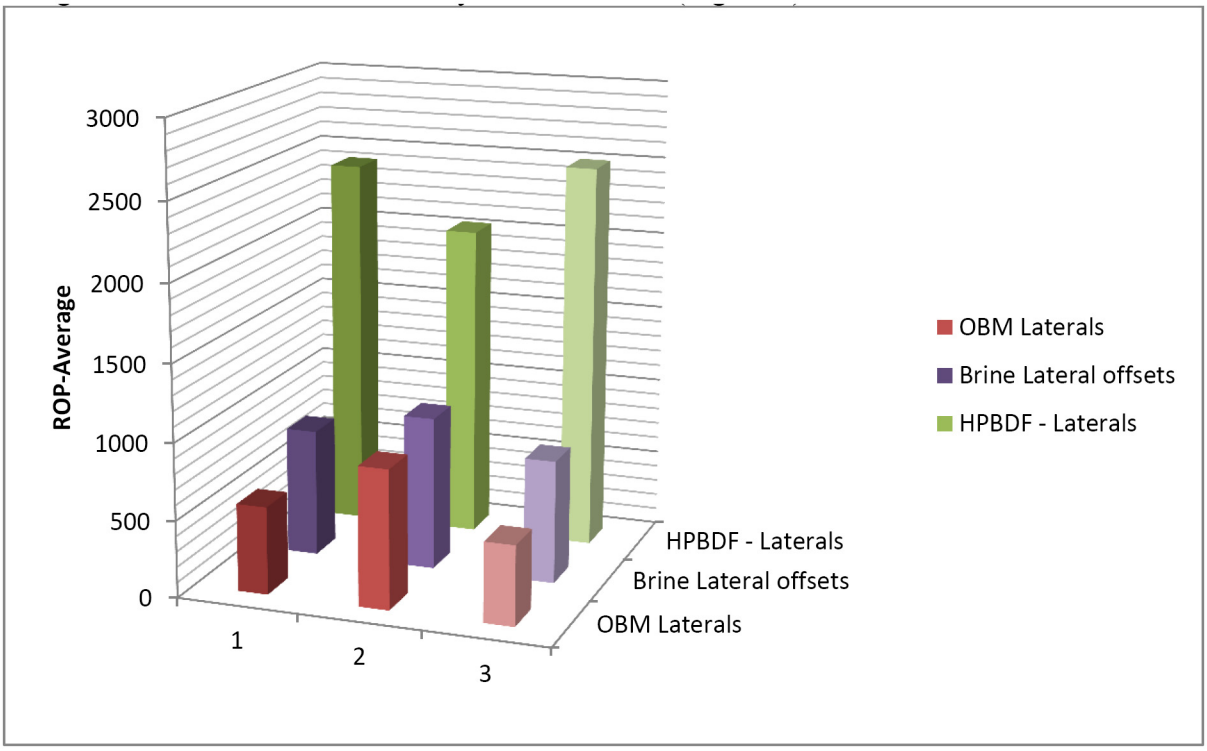

Figure 5—Average Daily ROP

Fluid Conditioner

The fluid conditioner assisted maintaining lubricity by retaining more HPDE's in the effluent and inhibiting deposition on the drilled solids. This kept the HPDE in the system to lubricate the wellbore and drill string interface. A byproduct of the dewatering process is the drilling fluid lubricity was not fully actualized. Testing on two different rigs using different dewatering equipment clearly highlights the advantages of fluid conditioner use. The lubricity coefficient was measured on both the active system and the dewatering units' effluents. The measurement aided in maintaining the HPDE concentration at 3%. As seen in Figures 6 and 7, without the fluid conditioner, there was a significant disparity between the active system lubricity and the effluent lubricity. Once the fluid conditioner was added to the drilling fluid, the HPDE was fully emulsified into the system. Figure 6 illustrates a significant drop in the lubricity coefficient for the effluent at the point where the fluid conditioner is added to the system. Further additions of the fluid conditioner show further stability of the HPDE into the drilling fluid. Interestingly, a maximum conditioner concentration occurs where the lubricity coefficient is no longer affected. In Figure 7 a similar conclusion is made. The operator decided to add the fluid conditioner in step by step additions on the current well. Although a slightly higher concentration than expected was needed, the additional fluid conditioner proved successful by decreasing effluent lubricity. There are too many variables to discern (from field data) why a higher concentration had an effect on the final lubricity. Further exploration is warranted yet it proves the possibility is available in some cases. However, it has been determined, statistically, that the fluid conditioner addition was effective in improving the effluent lubricity coefficient to be more like the active system lubricity coefficient (see the appendix for a discussion of the statistical analysis).

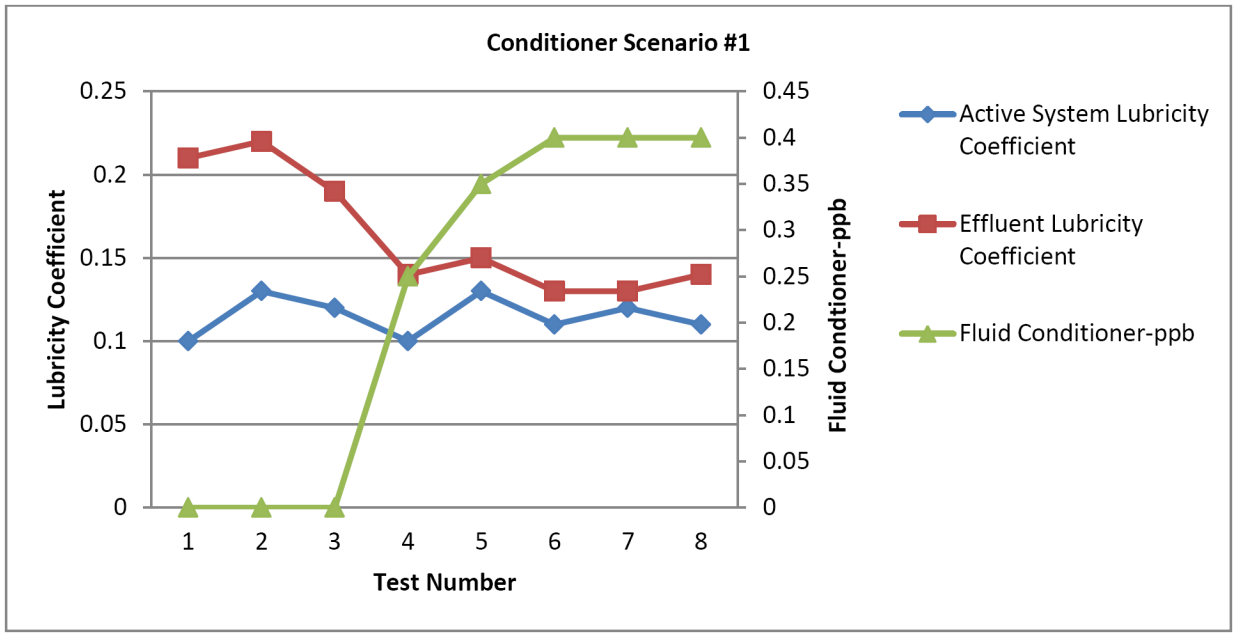

Figure 6—Scenario 1-Fluid conditioner effect on Lubricity

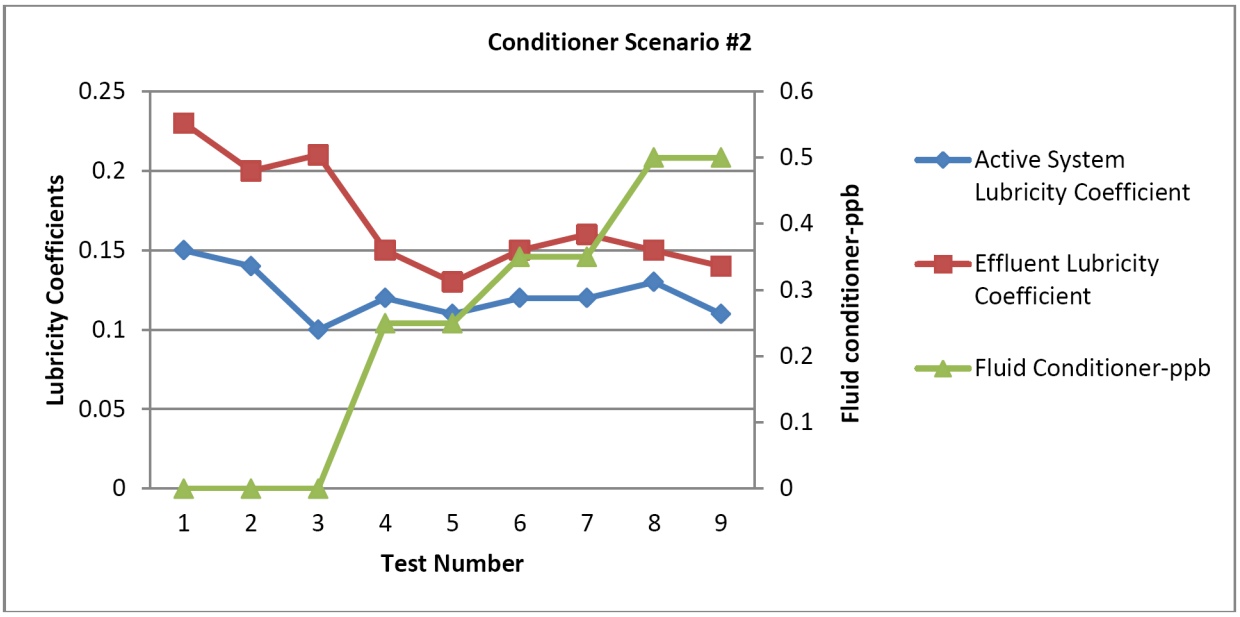

Figure 7—Scenario 2-Fluid conditioner effect on Lubricity

The lessons learned at these two wells proved very advantageous for subsequent wells.

Application of HPDE

HPDE performance is directly related to its concentration and how it is added to the fluid. The HPDE may be applied as a targeted concentration, in sweeps, or as continuous additions. Historically, the HPDE was applied as concentrated sweeps or as a percentage by volume in the total system with targeted concentration ranging from 3-5% by volume. Actual concentrations are difficult to determine due to the product being lost through degradation or by the solids control equipment. When applying the HPDE in sweeps, the effect is immediate but short lived due to the high annular velocities downhole. A third method was introduced and performance was compared. The HPDE was added as a continuous small stream, directly

to the suction while drilling. After reviewing the performance and cost, it was concluded that this methodology provided the same performance but reduced overall cost.

Cost Analysis

The fluid conditioner implementation and the modification of the HPDE application technique significantly reduced well costs. A comparison of average fluid costs before and after the changes show a 17.0% total cost reduction.

Three rigs that changed HPDE application techniques from the 'percent volume of total system' application to the 'continuous addition' application were compared in terms of HPDE usage. A 28.3% cost savings in lubricant usage was realized. Figure 8 further illustrates this point.

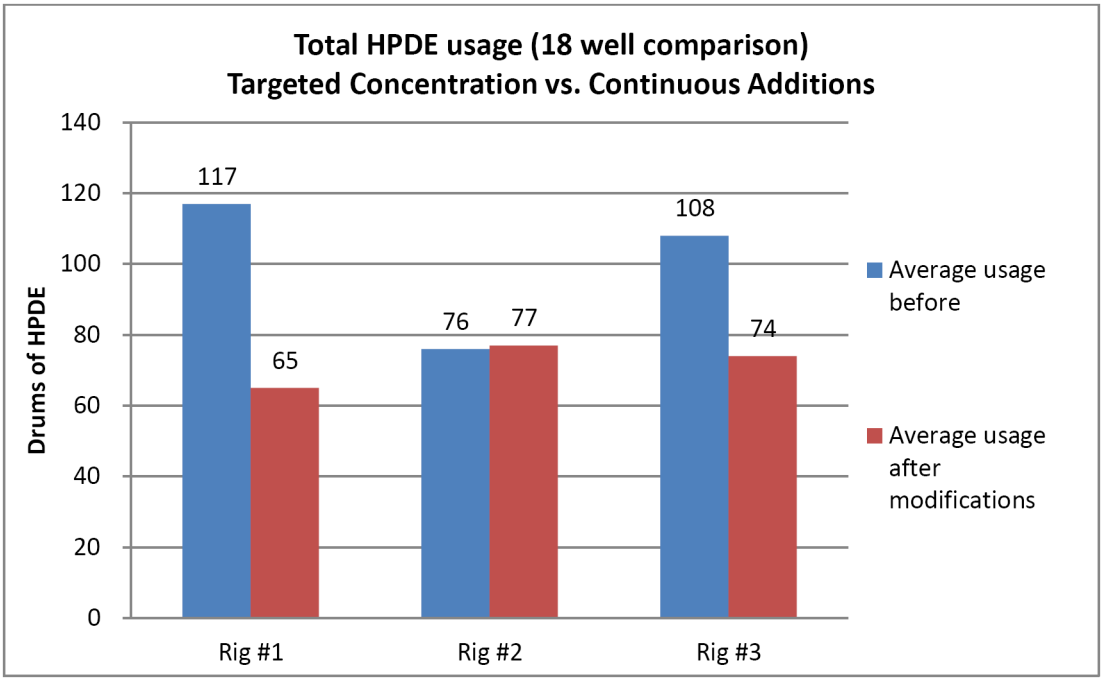

Figure 8—Average barrels of HPDE used before and after application change

Conclusions

Understanding the regional drilling challenges and the operator's requirements focused the technological development. A new fluid evolved based on produced brine knowledge and how dewatering procedures affect the operators' drilling success. Manufactured NaCl brine use was advantageous as the properties were better known and controllable. The increased cost necessitated using a fluid conditioner that supported the dewatering process and allowed the operator to reuse the drilling fluid by recycling the HPDE more efficiently. This fluid conditioner also allowed for better cuttings and crude-influx management. Changing the HPDE application technique to a small continuous stream offered improved cost performance. All factors assisted the operator in successfully drilling their wells with decreased cost in the Willison Basin.

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Appendix

Statistical Discussion on Significance of the Fluid Conditioner[8]

A full factorial involving two factors on the effect of effluent lubricity was conducted. The factors are described as:

1. The presence of the fluid conditioner (fixed factor)
2. The drilling rig (random factor)

These factors attempt to encompass all possible factors, e.g. fluid conditioner vs non-fluid conditioner. The drill site is considered to be the next possible factor that would influence the lubricity coefficient. As seen below, after running the analysis any other individual factors attributed to the drill-site are deemed insignificant.

The Analysis of Variance (ANOVA) table for this study is shown below.

Table 4—ANOVA for the Reduction of Effluent Lubricity as a function of Fluid Conditioner and Drilling Rig

General Linear Model: Effluent Lubricity versus Drilling Rig, Fluid Conditioner

Factor	Type	Levels	Values
Drilling Rig	random	2	A, B
Fluid Cond	fixed	2	Present, Not Prsent

Analysis of Variance for Effluent Lubricity, using Adjusted SS for Tests

Source	DF	Adj SS	Adj MS	F	P
Drilling Rig	1	0.0002060	0.0002060	68.44	0.077
Fluid Cond	1	0.0166856	0.0166856	5543.48	0.009
Drilling Rig*Fluid Cond	1	0.0000030	0.0000030	0.02	0.892
Error	11	0.0017283	0.0001571		
Total	14	0.0184933			

S = 0.0125348 R-Sq = 90.65% R-Sq(adj) = 88.11%

Using an appropriate alpha error ($\alpha = 0.10$), the analysis shown in the table indicates that both main effects are statistically significant factors ($p \leq 0.100$) in affecting the effluent lubricity. The probability of obtaining an F-value of 68.44 is 0.077 for ″Drilling Rig″. The probability of obtaining an F-value of 5543.48 for ″Fluid Cond″ is 0.009. These F-values are considered unlikely due to random chance and are therefore statistically significant. No interaction is found between the two effects.

The statistical importance of each effect (″Drilling Rig″ and ″Fluid Cond″) is 0.28% and 88.6%, respectively. In other words, the ‘rig to rig’ variability represents less than one percent of the variability attributed to the effluent lubricity reduction and thus its contribution to the variability is considered minor. The presence of the fluid conditioner explains 88.6% of the variability attributable to the reduction in effluent lubricity and is therefore considered to be the major influence in the reduction of the effluent lubricity coefficient.

To emphasize, it is highly unlikely that the final effluent lubricity coefficient occurs spontaneously when considering these two factors. There is a particular weight on the fluid conditioner vs drilling rig.

The effect on effluent lubricity for the conditioner before and after addition is shown in Figure 9.

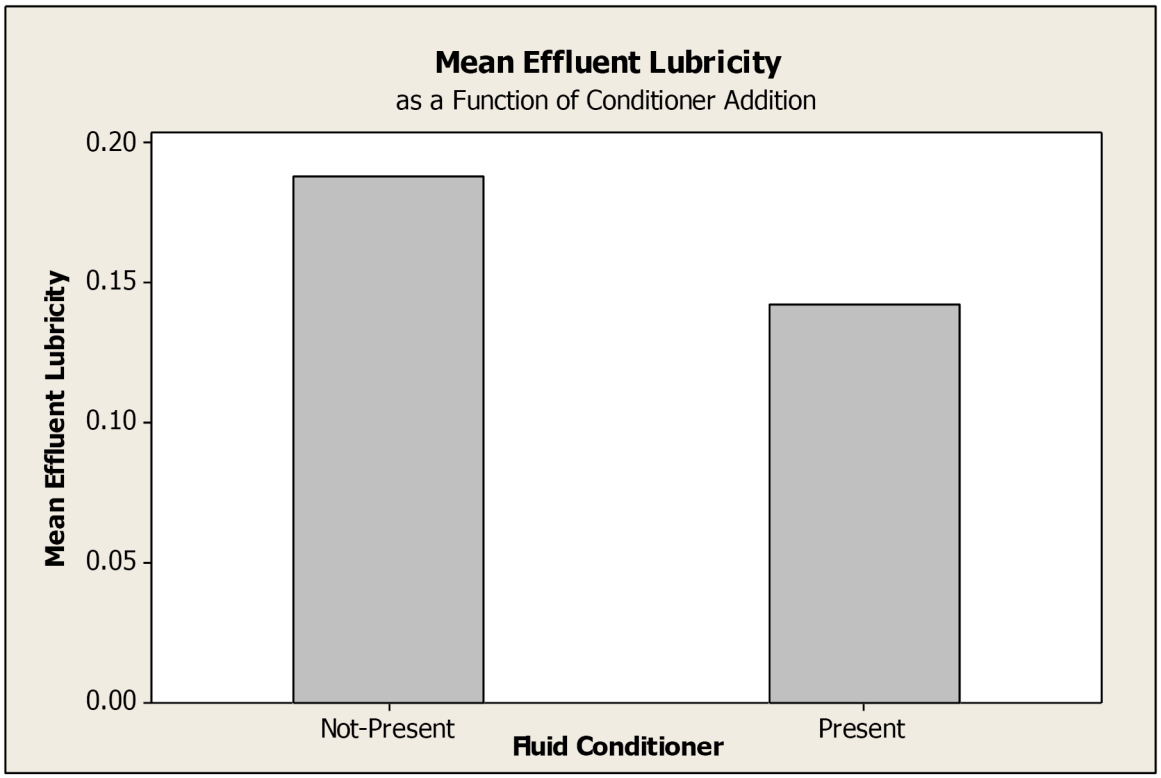

Figure 9—Graph illustrating effect of fluid conditioner on effluent fluid

A full factorial statistical analysis indicates that the fluid conditioner is a statistically significant and statistically important factor.