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High Performance Water Base Fluid Improves Wellbore Stability and Lowers Torque

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Abstract

In Southern Europe, a field known to have extremely unstable formations was drilled successfully with a specialized high- performance water-based fluid (HPWBF). Prior to formulating the HPWBF, laboratory analyses were performed on the formation using x-ray diffraction (XRD). The formation was found to be high in calcite, quartz and clays. The relative concentrations of the aforementioned minerals were variable; therefore, the samples' reactivities (measured by cation exchange capacities (CECs)) were also variable, increasing the difficulty of predicting reactivities when planning an appropriate drilling fluid. Previously, wells in this area endured costly and untimely sidetracks caused by stuck pipes and collapsing wellbores. The financial impact of lost time and equipment greatly reduced the profitability of the wells.

During the drilling program a drill pipe failure and subsequent fishing operations involved a successful recovery of the lost string and bit after nine days without circulation. Based off of previous experiences[1,2], the laboratory formulated and piloted a HPWBF to solve these challenges. Using various shale inhibitors and a high-performance drilling enhancer (HPDE), the fluid stabilized the wellbore and delivered a low coefficient of friction for torque reduction. The HPWBF was also customized with a unique blend of viscosifying agents to maintain rheological properties for optimum hole cleaning.

The HPWBF stabilized the wellbore, allowing the pipe and bit to be retrieved and pulled out of the hole without any issues after the nine days without circulation. This discussion will include the formation's XRD and CEC findings, general drilling fluid measurements such as lubricity coefficients, rheologies, wellbore stability, lab tests on corrosion and cement contamination, and a comprehensive overview of the well data including torque drilling days.

Introduction

Due to a number of problematic wells drilled in this area, a large amount of lab work was implemented to provide an appropriate and cost effective solution. Wellbore stability, while drilling in the highly unstable reactive formations became the goal and driver to develop the customized HPWBF. Wellbore stability presented a number of problems on previous wells using both water-based and oil-based fluids. The answer to the wellbore stability problem came in the form of a potassium formate HPWBF made with an array of chemicals that would strengthen the wellbore to maintain stability even during static conditions.

There will be a general discussion of geological samples obtained from the drill site, how they were analyzed and what implications they have on the problems experienced. A brief evaluation of the operator's well design will be addressed. The process of using and implementing the HPWBF and a detailed discussion of the well's achievements will also be analyzed. The lessons learned and current best practices involving the HPWBF will be discussed and concluding statements will be conveyed.

Offset Experience

All six offset wells drilled in this area experienced wellbore instability leading to costly sidetracks due to stuck pipe and collapsing wellbores. Primarily, these wells encountered the unpredictable formations in the 12 ¼″ intervals. These wells exhibited higher than normal CO2 levels. This lowered the pH of the drilling fluid and raised the potential for corrosion. The composition of this formation, discussed below, caused a very unpredictable and precarious drilling environment. In one particular offset well, an operator was forced to drill four sidetracks before successfully completing the 12 ¼″ interval. These sidetracks were very expensive and time consuming adding over half a million dollars in mud costs plus 161 days to the drilling projects. Due to its location and similarity to the subject well of this paper, this offset well serves as a reference point for the remainder of this paper.

Well Design

- Plug and abandoning operation (starting drilling operation from 965 m)
- Casing 13 3/8″ Intermediate set @ 2770 m (9088 ft) at 8.98°
- Casing 9 7/8″–9 5/8″ Intermediate set @ 4130 m (13550 ft) at 14.98°
- Liner 7 5/8″ set @ 4440 m (14568 ft) at 38.49°
- Slotted liner in 4 ½″ set @ 5575 m (18292 ft) at 90°

See Figure 1 for schematic.

Shale and Geological Analysis

Six samples from the subject well (from the 12 ¼″ interval) in increasing depths were analyzed by x-ray diffraction (XRD) and cation exchange capacity (CEC) while the well was being drilled. The laboratory's results showed that this series of samples were very inconsistent (See table 1).

Table 1—XRD Analysis on Cuttings Sampled From Subject Well

Sample Depth, m	3000m	3200m	3350m	3550m	3750m	3900m
Calcite wt %	49.01	25.14	63.68	67.03	24.89	23
Total clay wt %	15.95	34.97	6.28	6.86	44.2	26.58
Quartz wt %	12.26	14.83	10.56	6.83	20.12	20.68
Dolomite wt %	10.15	10.11	8.64	10.41	2.88	6.83
Birenessite wt %	6.23	0	0	0	0	2.14
Siderite wt %	4.24	5.52	5.08	5.2	7.48	8.3
Albite/Feldspar wt %	2.16	5.21	3.91	0.89	0.52	0
Mica (Biotite and Muscovite) wt %	0	4.22	1.51	2.61	0	11.05

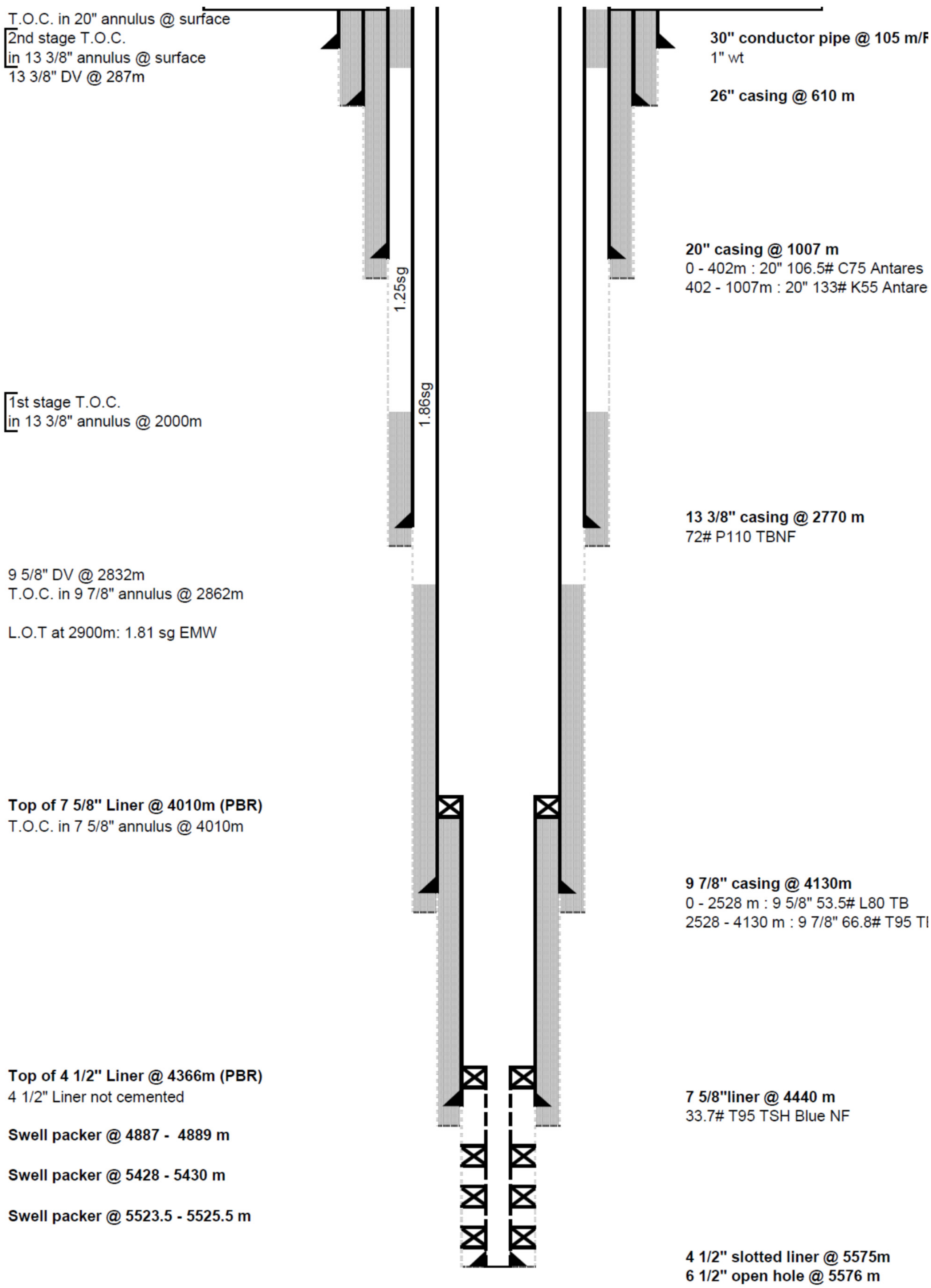

Figure 1—Well Design

The following chart (figure 2) was created to illustrate the lack of uniformity:

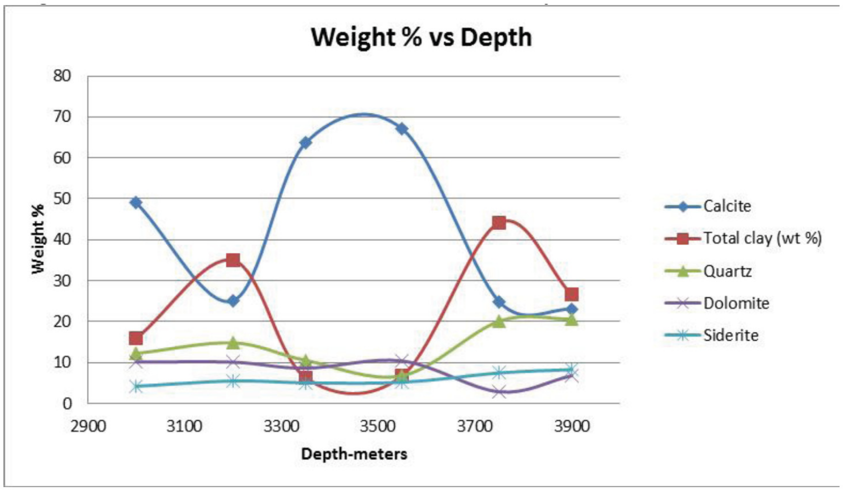

Figure 2—Graph illustrating the various minerals encountered

To re-illustrate the variability of the composition of the formations in this region, the table and graphs below (table 2 and figure 3) compare total clay content to the cation exchange capacity. This comparison shows a challenging, wavering environment.

Table 2—Total Clay Content to Cation Exchange Capacity

Depth	Total Clay (%)	CEC (meq/lOOg)
3000 m	16	13
3200 m	35	26
3350 m	6	NA
3550 m	7	NA
3750 m	44	30
3900 m	27	22

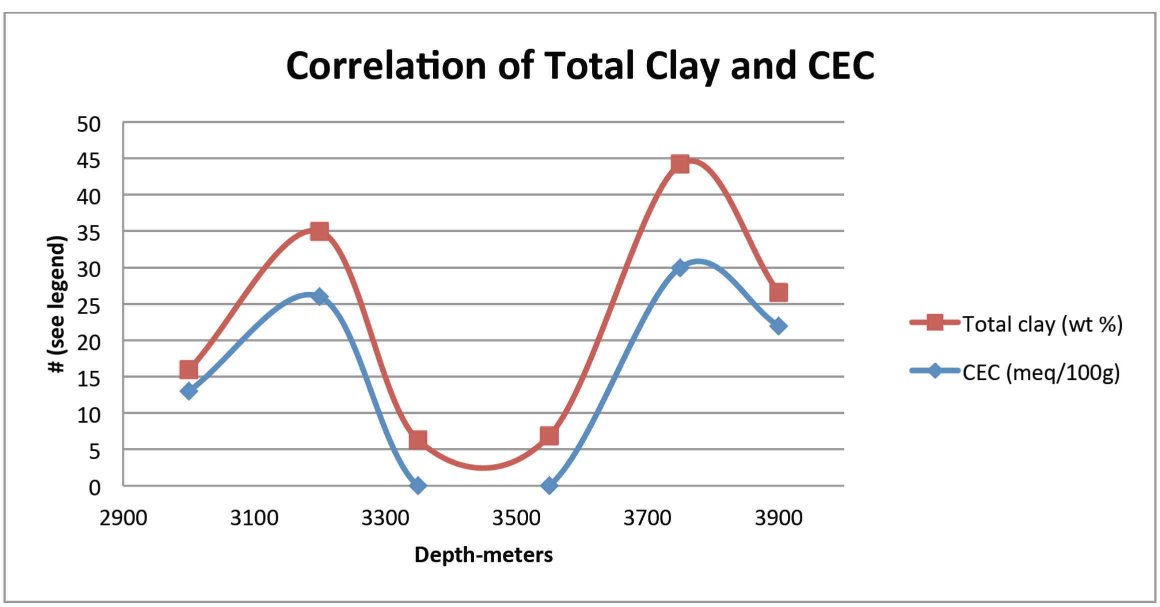

Figure 3—CEC and Total Clay Correlation

The total clay values and cation exchange capacities nicely parallel each other in the illustration below (See figure 2).

The individual clay species were analyzed, further exemplifying the varying geology of this region (See figure 4):

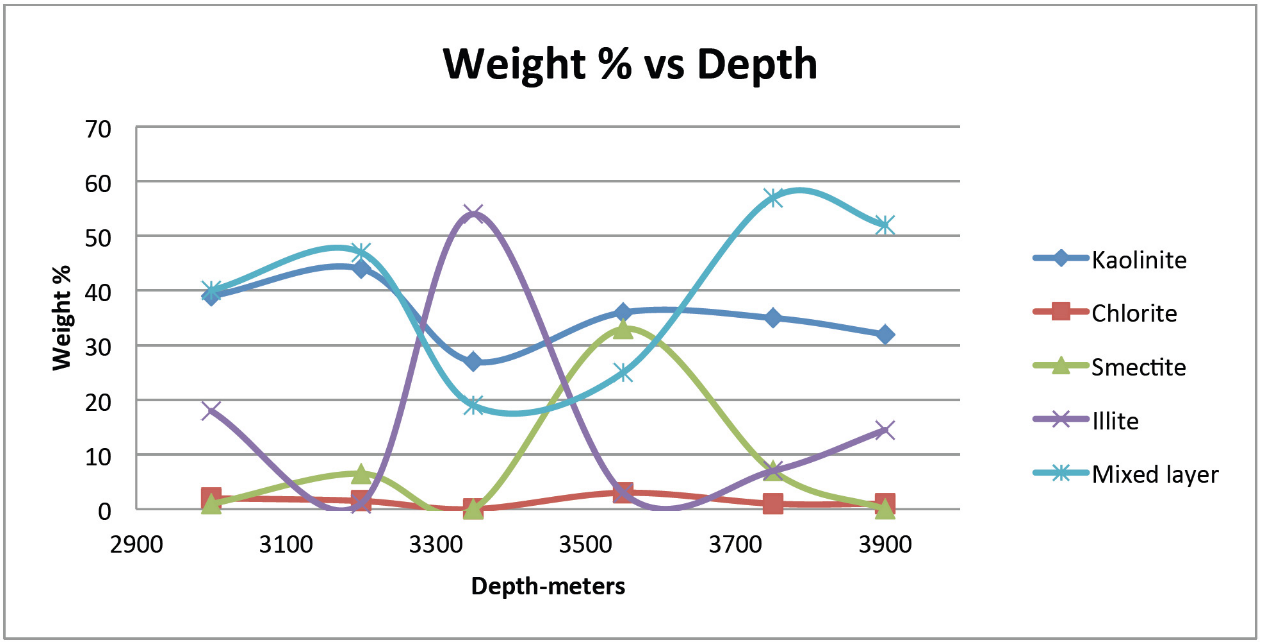

Figure 4—Individual Clay Species

Mixed-layer (S/I) and kaolinite were major constituents and chlorite was a minor constituent in all the samples. Each sample's uniqueness was defined by the presence of species like illite (non-reactive dispersive clay) and smectite (reactive & swelling clay). Kaolinite is non-reactive clays and maybe highly dispersible but can be readily stabilized by potassium formate[3]. This data supported the issues encountered on the offset wells.

Drilling Fluid Design, Selection and Formulation

The following benchmarks were established for the drilling fluid for this region:

- Borehole stabilization
- Inhibition
- Reduce torque values
- Increase ROP values
- Proper suspension and mobilization of cuttings through ideal hole cleaning properties
- Low lubricity coefficient for optimized rates of penetration and torque

The testing data below will confirm the usage of the following chemicals and fluid system:

- Potassium formate brine was chosen for its high viscosities and large osmotic pressures which make it suitable for shale drilling by reducing swelling pressures, shale water content and pore pressure at the same time[1]. It is also readily known that potassium formate stabilizes clays, in particular kaolinite[3].
- A High Performance Drilling Enhancer (HPDE) was introduced to increase lubricity, reduce torque values, and maintain the desired lubricity coefficient.

- Gypsum was introduced into the formulation due to the high amount of carbonates found in the formation water. Gypsum would help to precipitate the calcium carbonate. This would assist in stabilizing the formation while also precipitating $C0_2$ and to reduce the rate of corrosion.
- Siderite was chosen as the weighting agent due to its non-damaging properties for the formation. It is very acid soluble which also came as a benefit in the reservoir section. Due to this product's particle size distribution it is able to improve filter loss reduction.
- The amine-based product was chosen as the inhibitor of choice to further reduce the fluid loss and stabilize the formation.
- Sized calcium carbonate and graphite were used as sealing products.

Understanding the types of clays and the corresponding cation exchange capacities from samples collected in the nearby offset well narrowed down the drilling fluid suitable for these application requirements (see table 3). The offset well's cuttings analysis showed the presence of kaolinite (dispersible clays) and a discontinuous presence of illite (brittle clays) and smectite (swelling reactive clays). It was evident that there was a need to use a fluid able to provide inhibition and borehole stability.

Table 3—Offset Well Clay Composition

			Main Clay wt%					
Depth m	CEC meq/lOOg	% Clay	Kaolinite	Chlorite	Illite	Smectite	Mixed layer	Illite/smectite
2400	35.5	54	44	6	37	6	8	41/59
2500	42.9	60	44	4	36	8	8	41/59
2660	35.1	62	52	7	31	5	5	41/59
2730	55	61	51	3	26	7	12	47/53
2800	36.8	46	29	6	54	8	3	42/58
2970	55.5	55	23	13	49	15	-	-
3150	13.4	38	43	8	37	11	1	38/62
3250	25.3	47	8	10	4	3	75	31/69
3350	36.6	56	27	4	47	1	21	39/61
3440	14.2	53	52	3	33	6	5	39/61
3540	7.5	40	34	7	51	7	-	-
3640	22.3	4S	44	6	39	8	2	43/57
3498	19.2	54	70	6	15	2	7	40/60
3840	15.4	47	80	4	11	3	3	38/62
3946	16	43	63	7	25	4	-	-
3589	20	67	34	5	47	2	11	36/64
3760	22.8	71	70	2	16	2	11	35/65
4040	17	51	80	2	7	4	6	39/61
4140	14.4	44	41	8	48	3	-	-
4240	14.4	47	47	5	29	6	13	36/64

Four formulas were proposed. The shale problems anticipated were:

- Swelling
- Sloughing
- Dispersion

A shale recovery test was used to evaluate stabilization capabilities of the four formulations on each shale sample recovered from the offset well. The swelling test was also performed to evaluate the best brine able to inhibit the drilled clays. The results are illustrated below in figures 5 and 6.

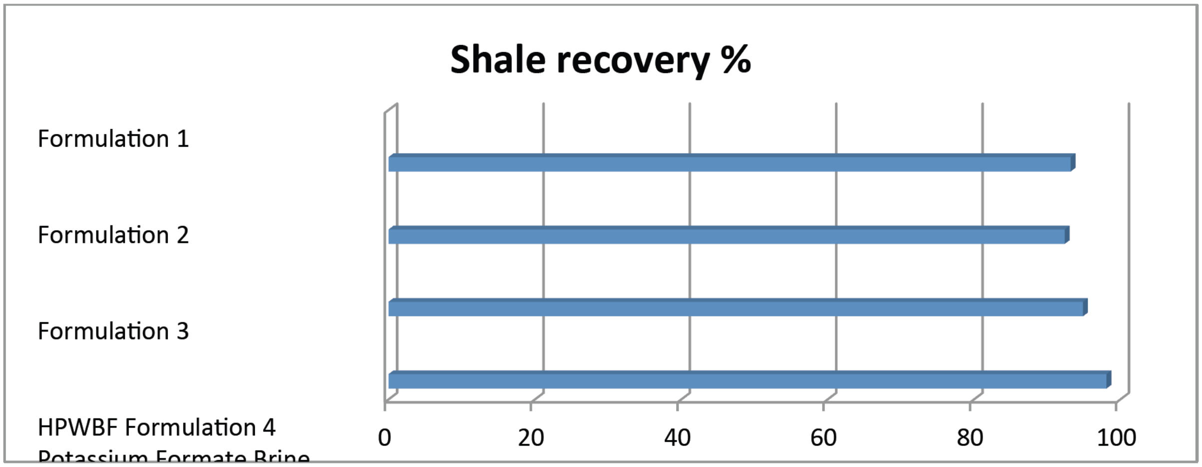

Figure 5—Shale recovery at 90 °C Cutting Samples from offset well Depth: 3980 – 4220 m, 4–12 mesh

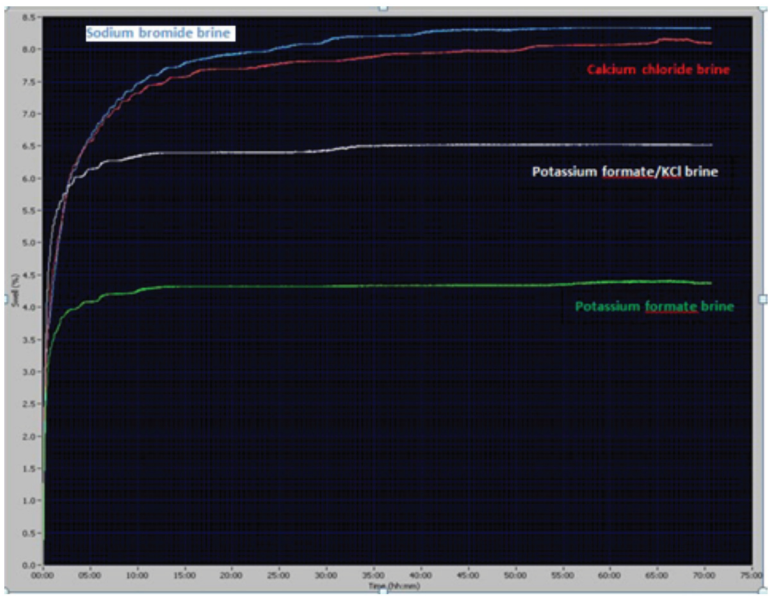

Figure 6—Swelling-75 Hours Cuttings samples from offset well Depth: 3980 – 4220 m

One of the fluids tested was the previously mentioned HPWBF. The proposed HPWBF exhibited a shale recovery of 98.1%. The potassium formate brine showed a lower swelling pressure than other brines.

The HPWBF was formulated and pilot tested in the laboratory using various shale inhibitors along with the HPDE to stabilize the wellbore further while lowering the coefficient of friction to reduce the torque encountered. The fluid was customized with a specific blend of viscosifying agents to maintain good rheological properties and ensure proper hole cleaning.

Formulation 4 was then tested in terms of its lubricity. Several versions of the formulation were created by varying the concentration of the HPDE. The fluids' lubricities were then measured before and after being hot rolled at 90°C for 22 hours. The results are illustrated below in figure 7. This experiment created a guide for the selection of the HPDE per desired lubricity coefficient.

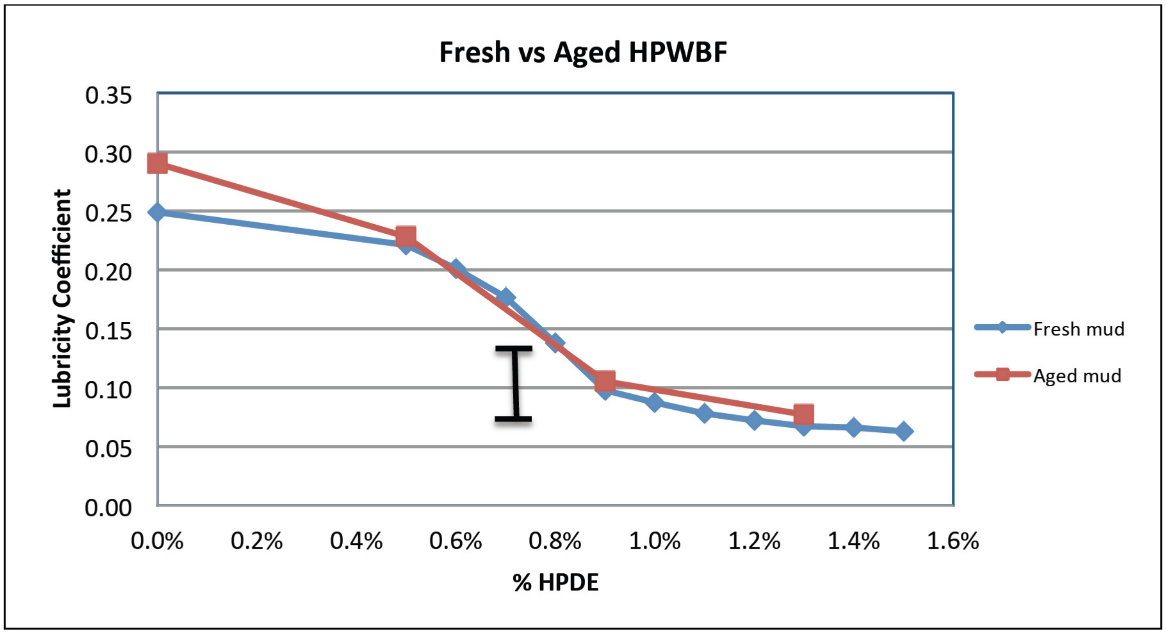

Figure 7—Aged Fluid Lubricity Performance Hot rolled 22 hours at 90°C

For precautionary purposes, the fluid was also tested for stability after cement contamination. The results below in table 4 provided a base line for what to expect and prepare a treatment regimen if needed.

Table 4—Cement Contamination Results

Parameter	Values	
Rheology T= 49°C (120°F)	Cement = 25%	Cement = 50%
600 rpm	64	70
300 rpm	50	56
200 rpm	40	46
100 rpm	33	34
60 rpm	28	30
30 rpm	24	26
6 rpm	15	17
3 rpm	10	12
PV (cPs)	14	14
YP (lbs/100 ft^2)	36	42
Gel10″/10′ (lb(lbs/100 ft^2)	10/15	15/20

The fluid had the additional benefits of corrosion inhibition as shown in the test results below. Offsets showed the formations to have large amounts of CO_2, which reduces the pH of the fluid, increasing the likelihood of corrosion. Corrosion on the drill string can cause stress cracking which will then cause tool joint failures. A fluid with corrosion inhibiting capabilities diminishes costly tool replacements. A sample of HPWBF was collected from the rig site and corrosion testing done. Table 5 shows corrosion rates that are considered acceptable.

Table 5—Corrosion Testing on HPWBF Taken From Rig Site

Time test	% (Loss weight)	Corrosion Rate (lb/ft^2/year)	Corrosion Rate (mpy)
3 days	0,76 %	0,98	24,1
7 days	1,35 %	0,76	18,7

Fluid Measurements and Performance

The general fluid parameters, outlined below, were established through the operator's experience (table 6):

Table 6—Target Drilling Fluid Parameters

Parameter	Specification
Average HPWBF Density	1.77 SG (14.8 ppg) Range (1.55–1.86 sg)
Average HPDE	1.0%
Average ROP On Bottom	3.0 m/hr (9.84 ft/hr)
Average Torque on Bottom	27.83 kN.m (20,526.35 lb.ft)
HPWBF Lubricity Coefficient	0.13

Torque and ROP were benchmarks for the fluid's success. The fluid's HPDE may be assessed by evaluating the ROP. The Torque and ROP in the first graph below (figure 8) maybe correlated to the concentration of HPDE as in figure 9. The ROP was not dramatically affected by a sharp increase in torque. The ROP averaged a satisfactory 3 m/hr outperforming many surrounding offsets in the area ranging from 0.5 m/hr to 2.0 m/hr.

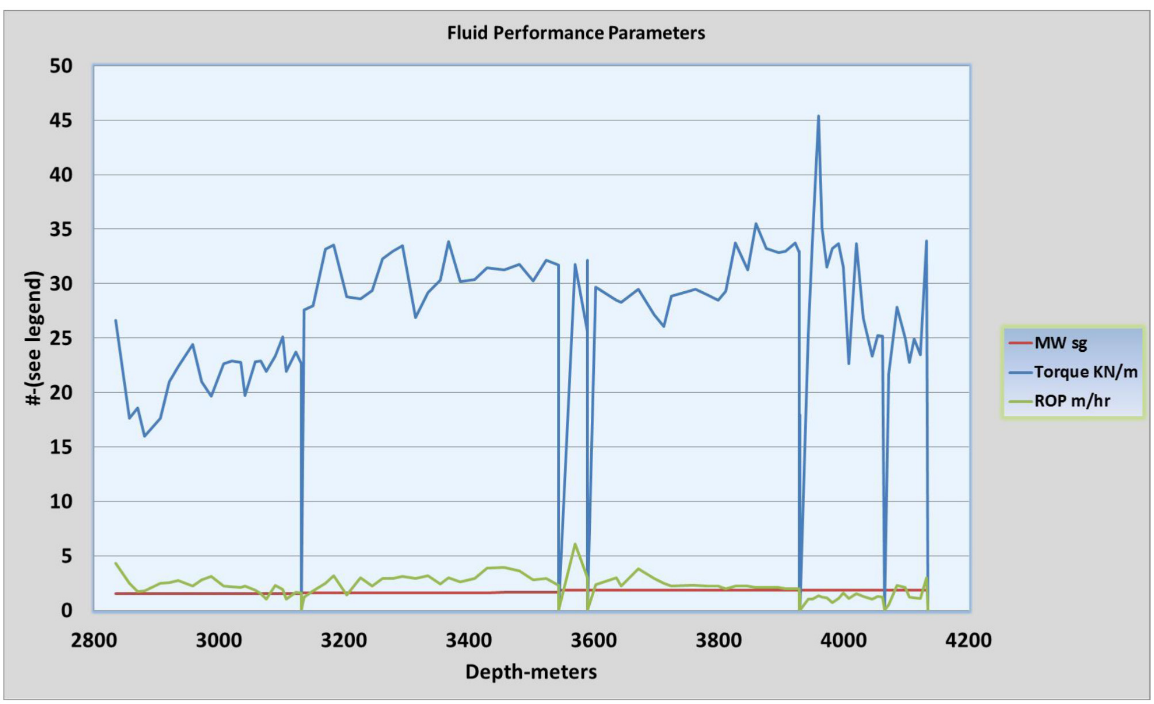

Figure 8—

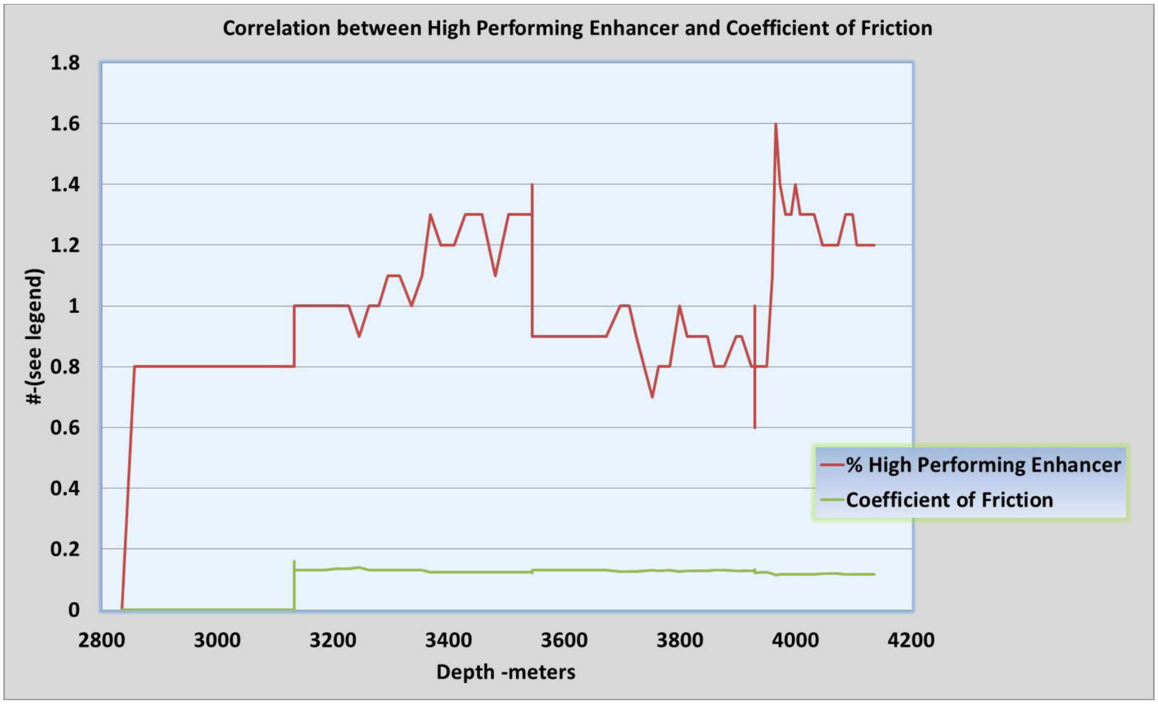

Figure 9—

An extreme pressure and lubricity tester measured the lubricity coefficient at the wellsite, monitoring the effectiveness of the HPDE. This ensured that friction factors were maintained in optimal ranges while product was used as economically as possible.

Drilling Results

At the wellsite, ROP, torque and lubricity coefficients were monitored to optimize the fluid. As drilling started, HPDE was added whenever the measured lubricity coefficient increased. All shale stabilizers prescribed for the fluid addressed each sedimentary deviation. No borehole stabilization problems occurred illustrating that the package of shale stabilizers was ideal to anticipate and alleviate any suspected shale problems.

The aforementioned testing, formulation, and planning paid off through the execution of the well plan. No side tracks occurred in the problem section, proving the fluid's value. The fluid surpassed expectations when a bit was lost down hole. During the attempt to retrieve the lost bit, the drill pipe was pulled out of the hole, and halted fluid circulation. This fishing attempt lasted nine days. At the end of the ninth day, the bit was retrieved off the bottom. When the drill string was extended back into the borehole, no wellbore instability sections were found. Compared to the aforementioned offset well, this was a great success and a lesson that would be used for future drilling campaigns in the area.

Conclusions

This paper describes the formulation and execution of a HPWBF used to drill in a region commonly known to have serious drilling challenges. The series of samples tested illustrated how varied the sedimentary layers were. Given this region's offset information and this genre of drilling fluid's historical experience, a customized fluid was able to be formulated to adapt to the highly various formation. Testing the fluid with the well's cuttings to identify problems areas and calibrate the formulation was instrumental to saving the operator time and money.

When a major drilling event occurred that caused the circulation to stop, the operator relied on the drilling fluid to keep the diverse sedimentary layers of the bore hole stabilized and the respective cuttings suspended. Compared to the offset well's behavior, the fluid seamlessly maintained pore pressure, cuttings suspension, and shale stabilization and inhibition. When drilling commenced, the fluid maintained its lubriciousness as expected from the aging tests done in the laboratory.

This HPWBF derivative is from a family of fluids well known to handle unconventional and adverse conditions[4,5]. The HPDE has proven itself to be adaptable to multiple drilling environments and keep friction factors manageable for maximized bit and drill string life[2]. The HPWBF fluid has consistently saved operators time and money. In this particular case, the fluid was diluted and partially used in the following 8 ½″ section. The potassium formate itself was later used in the 6 ½″ section to enhance the anti-corrosive protection needed in the extremely corrosive environment of the pay zone.

The information in this paper will prove valuable in future drilling campaigns. Excellent results may be obtained if all available information is utilized appropriately and accordingly. This is directly dependent on a team of experienced individuals that all have a mutual mission statement to use the best technology possible to drill a cost effective and environmentally responsible well.

Acknowledgements

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