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Customized High-Performance Water-Based Mud Delivers Superior Results while Driving Down Cost by Successfully Drilling through the Most Troublesome Shale Formations in the United Arab Emirates

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Abstract

In the UAE, drilling intermediate sections that contain highly dispersive clays with water-based muds almost always leads to mechanical instabilities in the form of pack-offs and tight spots due to highly laminated shale formations containing a high percentage of kaolinite. Operators have struggled with designing proper fluid systems to successfully drill these sections and have resorted to invert emulsion fluids (IEF) in certain fields, but that is not always an option. This paper presents the development and application of a high-performance water-based mud (HPWBM) that provided the required wellbore stability to drill these challenging shale sections through sealing natural and induced microfractures, and thereby reduced operational cost.

Based on extensive testing, technical experts customized the HPWBM system to drill the troublesome sections both in vertical and inclined wells. Multiple stages of testing were completed to understand the shale, including X-ray diffraction analysis, which revealed that mixed layers were present with a high-kaolinite content. The cation exchange capacity (CEC) was low, indicating that the clays were not reactive. The optimized HPWBM formulation included two powerful components for shale stabilization and a third key component to minimize fluid loss into the formation. The customized formulation underwent a complete suite of shale testing, including capillary suction testing, linear swell meter, shale erosion, shale accretion, as well as lubricity testing and stress testing.

Proper planning and execution, using best-available drilling practices, enabled the drilling of these challenging wells without encountering any significant issues that could impact rig time and increase costs. The selection of a customized HPWBM to provide shale stability performance and low-fluid invasion was fundamental to achieving the required fluid properties. Using this HPWBM system in these formations helped the operators achieve an average rate of penetration (ROP) of 43.7 fph – which was 62% higher than in the offset well and reach 40° inclination on different wells. There was also a reduction in the total volume used to drill the sections due to lower dilution rates compared to conventional systems.

As a result of the lower fluid consumption, the total fluid costs were significantly reduced compared to offset wells. The casing strings were run to planned depth with no recorded issues on the first two wells, and savings of 11 days were achieved when compared to the offset wells in the same field. The customized

HPWBM system with superior performance was able to achieve high levels of shale stability and inhibition without which this milestone would not have been possible. It made the possibility to drill these formations with an environmentally friendly, lower cost alternative to IEF a reality, which maximized the clients' returns by reducing the overall cost of ownership.

Introduction

Over the past 15 years, there has been an increased demand for water-based fluids (WBM), specifically for off-shore operations in response to stricter environmental regulations and cost considerations. Industry operators and service providers have required water based fluid solutions to replace the stable and inhibitive Invert Emulsion Fluids (IEF). Typical challenges with WBM include hole washouts, poor hole cleaning, bit balling, tight hole, excessive reaming and stuck pipe, sticky cuttings plugging shakers screens affecting overall performance of solids control equipment (SCE), difficulties logging, and problems running casing to bottom. These issues forced operators to reduce drilling performance expectations; by controlling rates of penetration (ROP), lowering deviation angles, drilling tangents, and avoiding sliding, all leading to non-productive time (NPT) either invisible or not. These resulted in an increased operational cost and put constraints on how the field could be optimally developed. Wellbore instability in shales is a major problem costing the petroleum industry US$900 million annually, according to conservative estimates (Fersheed et al 2002).

IEF systems have been established as the preferred solution for drilling problematic shale formations. As discussed by "Schlemmer et al 2002", IEFs generate a high membrane efficiency due to their low water activities, low filtrate intrusion in shale pore throat and formation of a mobile external film of the continuous phase plus surfactants.

The challenges these problematic shale formations pose are magnified in the Middle East region since oil reserves are capped with rocks predominately composed of shales, most of which are highly water sensitive. To make matters more challenging, there is a severe impact on rock stresses from the Al Hajar mountains in offshore Abu Dhabi, resulting in a high level of instability in the Nahr Umr formation. Nahr Umr is predominately composed of kaolinite and has a cation exchange capacity (CEC) below 20 mEq/100g (i.e., not highly reactive). Nahr Umr does however, have numerous natural fractures which when exposed to sea water can result in tensile failure. (Mehtar et al 2010) observed that high filtrate invasion in the micro-pores increased near wellbore pore pressure which can result in failure after extended exposure times.

In an effort to maximize reservoir contact for increased production, wells are drilled at higher inclinations. Increased well inclination wells have higher impact on shale stability and may require extensive geo-mechanical studies to determine the optimal fluid density.

This paper details the design phase of the HPWBM including detailed qualification testing. The field deployment in a deviated well and successful outcomes allowed the operator to successfully drill a series of wells with deviations up to 40° inclination and thereby maximizing reservoir production.

Fluid Design and Testing

The fluid customization phase is generally considered to be the most critical process to assure that well and fluid objectives are achieved. The pre drill phases for effective fluids design and deployment are illustrated in Figure 1 below. The first step in the process was to identify the drilling challenges which included multiple meetings with the operator to understand offset well data, lessons learnt from the previous fluid applications, non-productive time and formation data.

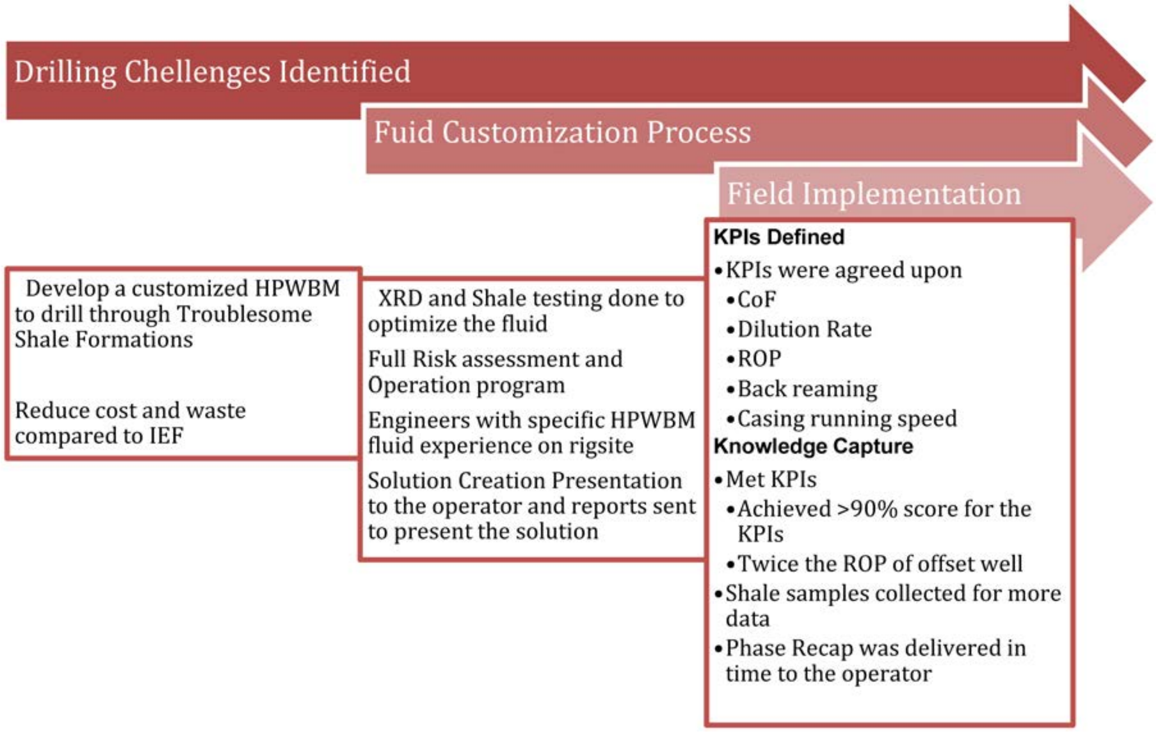

Figure 1—Fluid Design Process

The main challenges for the intended fluid application centered around drilling the troublesome shale formations and successfully completing the interval with minimal non-productive time and decreased costs. All identified challenges were ranked based on the operator's criteria. A fluid selection matrix was developed using critical thinking comparing different fluid solutions; the final HPWBM was selected due to its robust encapsulation, inhibition and sealing capabilities.

The next step in the fluid design process was to customize a solution through a series of shale specific tests that would demonstrate the fluid performance when drilling the formations of concern. Shale samples from the troublesome Laffan, Fiqa and Nahr Umr formations were secured. The following test protocol was completed:

1. X-Ray Diffraction (XRD) analysis to determine the composition of the shale. CEC testing was performed to assess the shale reactivity
2. Capillary Suction Time (CST) was used to optimize the base brine for the HPWBM system. An appropriate concentration of potassium ions ($K+$) in the form of Potassium Chloride salt (KCl) was determined to support shale inhibition
3. Once the base fluid was determined, the Shale Erosion, Liner Swell Meter (LSM) testing and Shale Accretion Testing was then optimized using different inhibitors and stabilizers to ensure the fluid formulation would provide the required formation stabilization and inhibition.
4. On completion of the shale testing, the balance of fluid qualification was performed and the formulation was optimized. Qualification testing included filtration testing against permeable media at expected downhole temperatures. Testing also included fluid rheology, as well as ageing (stability).
5. The resulting fluid properties were then used in hydraulic simulations to verify proper hole cleaning in the planned interval with expected drilling parameters.

The XRD data showed that the different formation layers had different risks of destabilizing with the highest risk towards the bottom of the Nahr Umr formation. The deeper Nahr Umr formation has a higher kaolinite content and the adverse interaction of this clay mineral with excess potassium ions (Table 1 below) is well known. The risk of destabilization is also accompanied by an increase in the reactive clay content (a combination of illite and smectite mixed layers) that also increased as the formation deepened. With this data in hand the next step was to start choosing the most suitable brine for the HPWBM. The brine in theory should include sufficient KCl to inhibit the reactive shale but not in excess that would destabilize the higher kaolinite formations. From the testing below (Table 2), KCl at a concentration of 3 wt% reduced the CST by at least 50% in all the shale samples tested. Further reductions were achieved by increasing the KCl concentration to 6 wt%. However, it was decided that a concentration range of 3-5 wt% KCl was optimal for drilling these formations while keeping the KCl levels closer to the 3wt% to keep the shale integrity whole. Once the correct KCl salt concentration of 3-5 wt% was chosen the full brine including the Sodium Chloride salt (NaCl) was retested to make sure the combination of the two salts would not have a negative effect on the shale inhibition. These formation shale samples are more prone to dispersion than swelling as indicated in the CEC values. The increased dispersive tendency of the kaolinite rich Nahr Umr shale can be inferred from the XRD results in Table 1 below.

Table 1—XRD data and CEC of the shale samples

Mineralogical Composition	FIQA	NAHR UMR Top	NAHR UMR Bottom	Laffan Top	Laffan Bottom
Smectite/Illite reactive Clays %	12	18	16	20	20
Kaolinite %	8	38	49	24	40
Chlorite %	2	6	8	4	6
Quartz %	18	14	21	8	12
Calcite %	53	19	3	41	20
Dolomite %	1	1	-	2	Trace
Anhydrite %	4	1	Trace	-	-
Halite %	1	1	1	Trace	1
Pyrite %	1	2	2	1	1
CEC Value (mEq/100g)	6	9	8	10	10

Table 2—CST testing results for the Nahr Umr and Laffan shale samples

Shale sample	Test solution	Average
FIQA	Fresh water	254.65
	3% KCl	127.65
	6% KCl	76.75
NAHR UMR Top	Fresh water	259.2
	3% KCl	111.2
	6% KCl	75.3
NAHR UMR Bottom	Fresh water	249.9
	3% KCl	118.6
	6% KCl	73.75
LAFFAN Top	Fresh water	230.7
	3% KCl	122.95
	6% KCl	95.65
LAFFAN Bottom	Fresh water	232.55
	3% KCl	121.35
	6% KCl	96.35

After selecting the appropriate base brine for the HPWBM, the next phase was to optimize the shale inhibition and encapsulation properties of the HPWBM. The aforementioned properties were optimized through a series of laboratory tests including Accretion, Linear Swell Test (LSM) and Shale Erosion testing. Table 3 is the final fluid formulation for the HPWBM as well as the WBM formula used on the offset wells. These properties were then compared to the Water Based Mud (WBM) used to drill the reference offset wells to confirm that the HPWBM would further reduce the risk of bit balling and wellbore instability.

Table 3—Final HPWBM Formulation vs WBM fluid used for testing and offset well

	HPWBM Formula	WBM formula
Product	Concentration lb/bbl	Concentration lb/bbl
Salt Brine	0.791 bbl/bbl	0.891 bbl/bbl
KCl Salt	10.8	26
Ca+ Treatment	0.5	0.5
Viscosifier	0.75	0.5
Fluid loss reducer	7	7
pH Control	0.5	0.5
Nano Sealant	10	-
Amine Shale Inhibitor	10	-
Low Molecular weight Polymer Stabilizer	10	-
Weighting Material	60	80
PHPA	-	3
Glycol	-	4
Bridging Material	30	30
LCM/Bridging	10	-
CO_2 scavenger	0.5	0.5
Oxygen Scavenger	0.4	0.4
Biocide	0.5	0.5

The HPWBM fluid tested consisted of 3% volume by volume of each Amine Inhibitor, Low Molecular weight polymeric shale stabilizer and a Nano Sealant.

Due to the limited number of cuttings available from past wells the capability of the HPWBM to minimize the shale accretion risk was tested using both London Clay and sized Bentonite pellets, to show how different types of clay solids would react to the inhibition products used in the formulation. London clay has a high content of illite/smectite mixed layers (up to 50% or higher) as well as a kaolinite content of approximately 10%. It has been shown elsewhere that shales with a high illite and kaolinite content are more susceptible to accretion when exposed to WBM. The sized Bentonite pellets were made of an untreated Wyoming bentonite (montmorillonite) which is a highly swelling clay mineral (Cliff et al 2008). The HPWBM inhibition performance was compared to that exhibited by the WBM used to drill previous wells in the field. The HPWBM showed an approximate 2-fold improvement in the inhibition of accretion for both clay types when compared to the previous WBM (Figure 2 and 3). As alluded to above, the London clay containing both illite and kaolinite had high accretion rates than the sized Bentonite pellets.

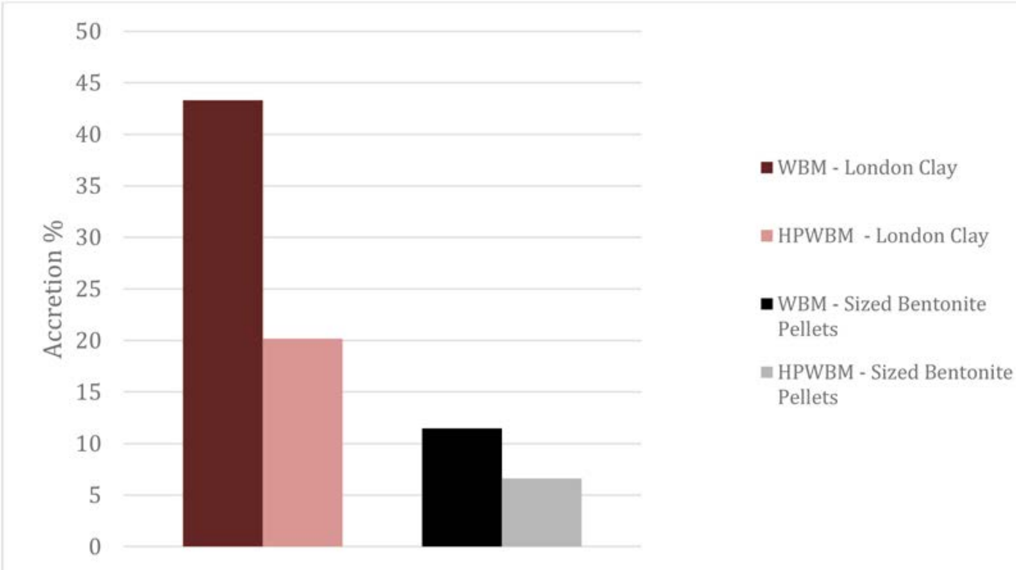

Figure 2—Accretion Testing using different Shale types

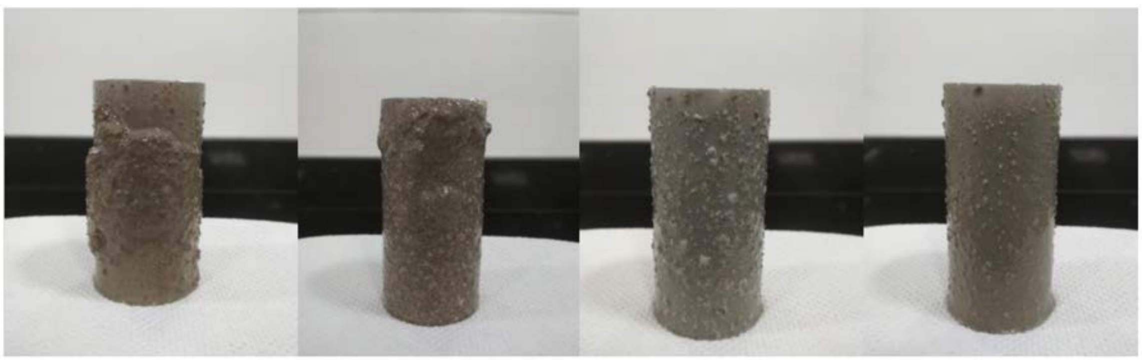

Figure 3—Accretion Testing Pictures – From left to right – WBM London Clay, HPWBM London Clay, WBM sized Bentonite pellets, HPWBM sized Bentonite pellets

The LSM test used small core like pellets made from the bottom of Nahr Umr formation shale. The pellets were exposed to different types of fluids to show how they would react in terms of swellability percentage. The results are shown in Figure 4 below which confirmed that an IEF would be the best in terms of inhibition. However, this was not an option due to environmental regulations and the excessive costs associated with waste treatment and facilities. The next best fluid inhibition performance was by the HPWBM chosen for this application with less than 3% swelling tendency. An observation can be made with the sudden increase in the WBM results below which can be attributed to an artifact such as vibrations on the countertop during the LSM testing phase. Due to the limited amount of shale available retesting was not possible at the time however multiple tests have been concluded on similar type shales afterwards showing the same result trend. This test was repeated several times on different shales to confirm the results. The outcome showed that the Amine Inhibitor used was effective and the concentration was optimized for this shale formation.

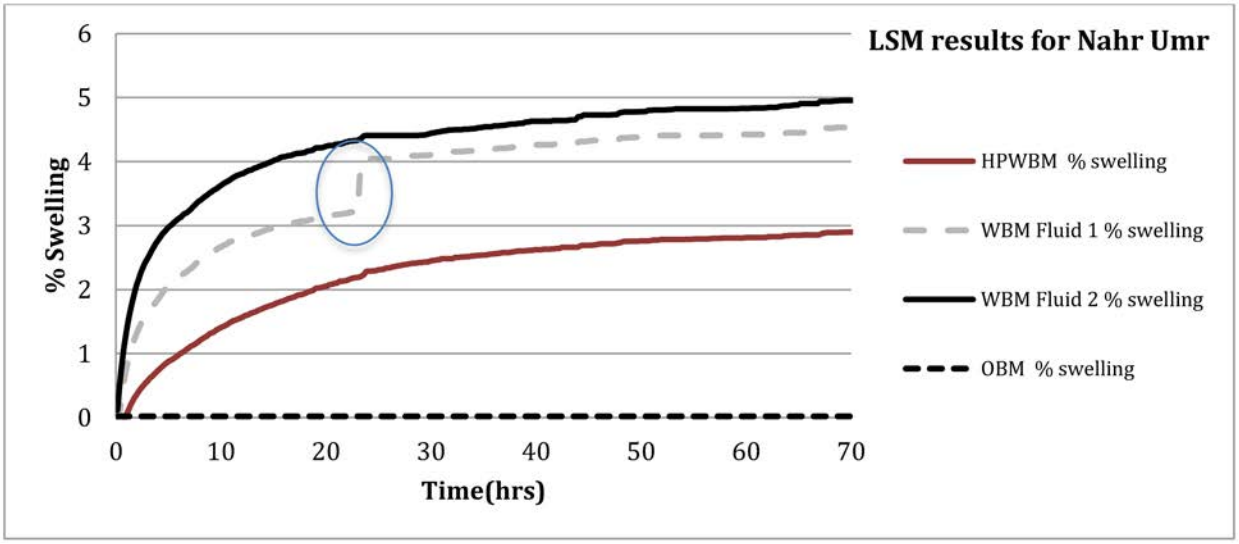

Figure 4—Linear Swell Meter Test Results on Nahr Umr shale samples comparing offset WBM to HPWBM and OBM

Finally, the most important of the tests was to ensure that the shale would not erode or disperse with this HWPBM design due to the high concentration of kaolinite in the specific shale. The shale retention test or Shale Erosion test was completed to determine the percentage of the shale sample that would remain intact when exposed to this customized fluid solution. This test showed above 90% shale retention by weight when testing the most reactive shale sample taken from the bottom of Nahr Umr shale as seen in Table 4 proving that the fluid solution was a success in term of being customized for the specific needs the client had to drill these formations. This result was then compared to the erosion test done on the offset WBM fluid that showed results of 78-81% retention proving the importance of the HPWBM for these formations.

Table 4—Shale Erosion Test for HPWBM vs WBM

Shale erosion test for Nahr-Umr samples		
	Sample 1	Sample 2
Nahr Umr Shale Retention in HPWBM	90.30%	91.70%
Nahr Umr Shale Retention in WBM	81.20%	78.40%

The fluid formula was then retested and optimized for rheology and fluid loss along with basic fluid properties following the approved API 13 I and API 13B-1 procedures with recorded fluid properties evidenced in Table 5 below. Reducing the fluid invasion into the formation was key in the success of the HPWBM fluid design process. For this reason it was imperative that the fluid tested showed the ability to form a thin impermeable filtercake under high temperature high pressure (HTHP) fluid loss conditions. This test was completed on a 10 micron ceramic disk at 250° F and 500 psi which showed the filtrate to be 3.1 mls after 30 mins and a filtercake of 1/32 inch shown in Figure 5. Both the size and the concentration of the bridging solids needed to be considered (McMillan, et al 2012). This illustrates that the fluid bridging and fluid loss additives along with the polymeric sealant used achieved the desired reduction in fluid loss intrusion into the formation by creating a barrier on the formation face to stabilize the shale.

Table 5—Final Fluid Properties for HPWBM

		Initial Properties	Properties after Hot rolling for 16 hours at 250 F
Rheology	Temperature [ºF]	122	122
	10 s Gel [lb/100ft2]	9	11
	10 min Gel [lb/100ft2]	13	16
	PV [cP]	29	31
	YP [lb/100ft2]	28	30
API Fluid Loss	Pressure [psi]	100	100
	Filtrate Volume [ml]	1.2	1.4
HPHT Fluid Loss on Disk,	Temperature, °F	250	250
	API Disk Micron Pore Throat Size	10	10
	Pressure, psid	500	500
	Filtrate, ml	2.8	3.1
	Total HTHP Filtrate, ml	5.6	6.2
pH	pH	9.98	9.94
	Temperature, °F	75.2	75.2

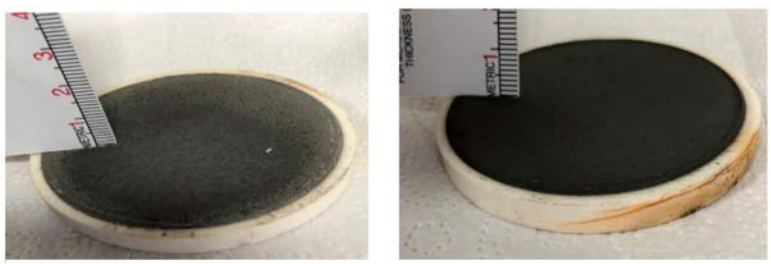

Figure 5—Filtercake Pictures of the HTHP for the HPWBM on ceramic disk

Operational Execution

When the HPWBM had met the established acceptance criteria, a set of Key Performance Indicators (KPI) were established with the operator for the deployment phase. The main KPIs were set as a direct comparison to the WBM used to drill the offset wells.

The main KPIs that were established for the interval are as follows:

- The dilution rates of the proposed HPWBM should be less than the WBM used on the offset well that was used for comparison.
- The friction factors of the HPWBM should be lower than the offset well. The coefficient of friction (CoF) should be lower than 0.25.
- The HPWBM should present higher ROP than the offset well with lower overall interval time (excluding NPT due to equipment failure).
- Back-reaming time should be less than any back-reaming previously experienced drilling Nahr Umr offshore Abu Dhabi
- Casing running time lower than offset wells.
- Lower washout percentages than offset wells, specifically in troublesome Nahr Umr formation
- No stuck pipe incidents related to drilling fluid.

Once the proposed fluid and KPIs were set and approved, the HPWBM was deployed in the field and a fluid performance was monitored. Methylene Blue Test (MBT) values were tracked to ensure minimum dispersion of the shale into drilling fluid. The MBT was performed every 4 hours in the field and treatments were planned and executed accordingly. The MBT showed maximum values of 7.5 pound per barrel (Figure 6) which was almost 50% lower than what was seen in the offset well using WBM. This was a crucial indication to the success of the drilling fluid because of the high nature of dispersion of these shale formations. Cuttings integrity was monitored throughout the interval through observations of cuttings returns at the shakers. The cuttings were well encapsulated and dry, exhibiting expected inhibition. Deep markings from the PDC cutters were visible.

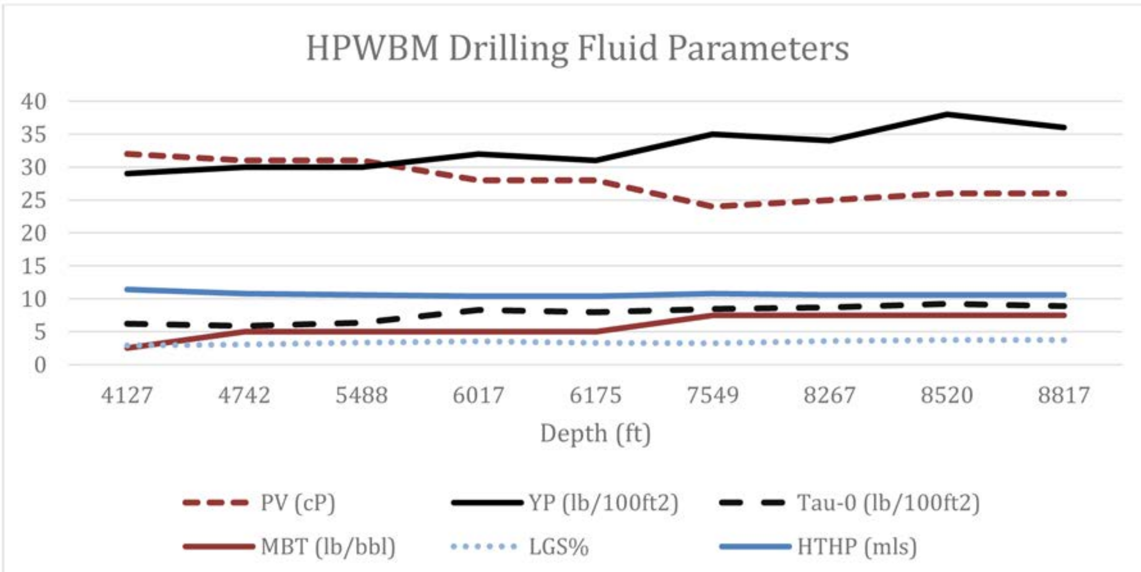

Figure 6—HPWBM Parameters While drilling

Due to the time dependent factor for these formations, High Temperature and High Pressure (HTHP) filtrate was monitored throughout drilling (Figure 6) to ensure minimum filtrate intrusion into the shale micro fractures. Supplemental treatments were required with the addition of the nano sealant and filtration control additives. These treatments decreased invasion and minimized pressure transmission in the near wellbore.

In stark contrast to the offset well, no sloughing or cavings were observed while drilling the interval with HPWBM, and caliper logs indicated a gauge wellbore confirming improved shale stability. While tripping out of hole, a few tight spots were observed and minimal back-reaming was required as a consequence. The Nahr Umr formation remained exposed to the HPWBM for 7 days with no indication of wellbore instability. The stability was achieved by minimizing filtrate invasion through prudent use of cross-linked polysaccharides, bridging material and polymeric sealant technology.

The rates of penetration recorded were a significant improvement compared to the offset well. On the well that the HPWBM was deployed, the average ROP was 43.7 ft/hr with instantaneous ROP reaching 120 ft/hr. The well drilled with HPWBM achieved ROP approximately 62% higher than offset wells drilled with WBM. The BHA and bit were able to drill the full interval in a single run without any weight on bit (WOB) transmission issues, and clear indications of the low CoF of drilling fluid was noted on trips. Additionally, no accretion or bit balling tendencies were observed when BHA was back on surface, which was notable given the experience with WBM on the offset well.

The HPWBM exhibited a very stable rheological profile while in dynamic conditions resulting in a superior hydraulic profile enabling improved overall hole cleaning efficiency as can be seen in Figure 6.

The total volume of HPWBM used to drill the interval was 30% lower than the offset well for the same length drilled, confirming lower dilution rates required. The lower dilution was a consequence of the HPWBM encapsulation and suppression of dispersive shales. The fluid performance supported maximum solids control equipment (SCE) efficiencies to control solids build up and minimizing the need to dump and dilute while drilling. The operator confirmed from caliper logs that that the drilled hole was gauge whereas the offset well drilled with WBM had hole enlargement and washouts across the troublesome shale formations. There was no instance of non-productive time while running casing and during subsequent cementing operations.

After drilling the interval, a summary of comparative performance was completed to confirm the successful deployment of the HPWBM. As evidenced in Figure 7, an increased ROP was achieved using the HPWBM compared to the offset well that was drilled with the WBM. The previous offset well that was drilled with the WBM fluid used in the shale testing comparison study in the testing phase of this paper had the same section length, inclination, hole size and was drilled in the same field. It therefore serves as an appropriate comparison between the WBM and the newly developed HPWBM. The offset well showed longer time required to run the casing due several tight spots which required condition trips before re-running the casing which increased the non-productive time.

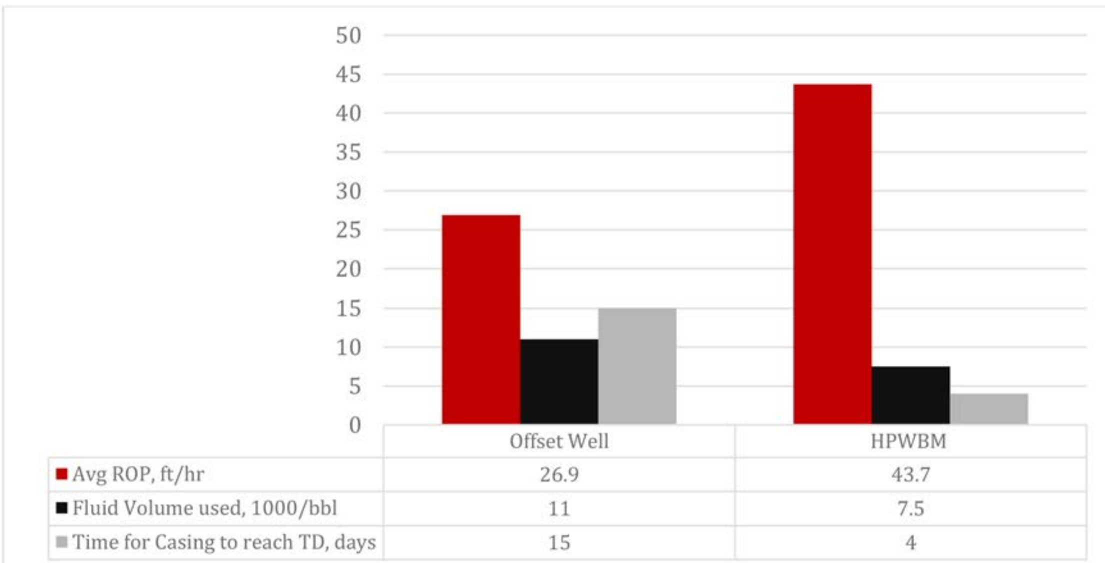

Figure 7—Comparison between Offset Well drilled with WBM and HPWBM Well

Results and Conclusion

In conclusion the customized HPWBM was able to meet and surpass all the agreed upon KPIs set prior to drilling this large diameter vertical wellbore section compared to the offset well drilled with WBM while achieving superior hole cleaning properties. This was achieved through proper Hydraulic Modelling software simulations along with the state-of-the-art shale inhibition suite of chemicals and extensive fluid engineering that was specifically designed for these shale formations. The fluid was able to reduce the non-productive time required to drill the well by 30% compared to the offset well drilled with WBM and successfully navigate drilling and running casing through these troublesome shale formations.

The combination of the Amine Inhibitor, Polymeric Stabilizer and Nano Sealant proved to be the precise solution needed for this application demonstrating that with the correct planning and testing protocol completed ahead of the field execution the fluid system design can be specifically optimized and customized to drill even the toughest of formations. Since then this HPWBM has been successfully deployed in different fields to drill more wells in country through these same formations of Laffan and Nahr Umr shale with higher reactive tendency having CEC values reaching up to 20 mEeq/100g. These wells have reached higher degrees of inclination reaching up to 40 degrees successfully to date.

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