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Optimized High-Performance Water-Based Mud Successfully Drilled Challenging Sticky Shales in a Stratigraphic Well in Saudi Arabia

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Abstract

Stratigraphic wells were drilled to target member (A) composed of sticky shales with streaks of sandstone and member (B) composed of sandstone and gravels. The majority of washouts that occur for member (A) occur because of sloughing of the shale, which leads to wellbore instability; therefore, the team determined the need for an optimized inhibitive fluid chemistry.

The problematic member (A) shale in this stratigraphic well was drilled with a high-performance water-based mud (HPWBM), which achieved the required drilling fluid parameters. The optimized HPWBM provided maximum inhibition and stabilization while drilling this sticky shale; a significant portion of the 12-in. hole was drilled in 34 hours at a rate of penetration (ROP) of 31.3 ft/hr. The average hole size from caliper logs was 12.4 in., i.e., only a 3.2% increase, well below the allowable success limit of 20% washout (14.4 in). In addition, eight trips were performed during the drilling phase without any tight spots. The drilling process was simulated with advanced hydraulics software for optimized hole cleaning, drilling rates, and tripping speeds, which enabled reduction of non-productive time (NPT). High-viscosity sweeps were used to enhance hole cleaning every 30 ft, though the high-viscosity sweeps carried only 3% to 5% of the extra cutting loads than during the normal drilling process. Because of the excellent hole conditions, a cleanout trip was not required after the last logging run nor before running the 9⅝-in. casing. No down-hole losses or differential sticking was encountered while drilling, tripping or running the 9⅝-in. casing. This paper presents the case study of successful drilling of the member (A) and highlights experimental and practical field application.

Introduction

Non-aqueous drilling fluids (NAF) are often the choice when drilling shales. Despite differences among types of shale, NAF generally delivers good drilling performance in all of them. NAF provides shale stabilization, lubricity, and contamination tolerance, which is difficult to achieve with a water-base mud (WBM). NAFs succeed in shale because the non-aqueous phase that faces the formation is not reactive, compared with water, which is reactive to the formation (Darley and Gray 1988). The performance of WBM can vary widely depending on the type of clay in the shale. For example, smectite is a swelling clay where as illite and kaolinite are dispersive. Some shales become sticky on contact with water, forming balls that can plug the annulus and lead to the accumulation of colloidal solids. Because of this variation in clay reactivity to water, WBM must be optimized to get the appropriate performance.

NAF has consistent drilling performance; however, it also has some drawbacks. Environmental concerns limit or prohibit use of NAFs in certain areas of the world, depending on composition. For example, in North America diesel-based NAFs are restricted and in the North Sea, common NAF components such as emulsifiers and other surface active agents are prohibited. NAF is also expensive compared with WBM, with additional costs for cuttings disposal and base oil transport (Deville et al. 2011; Wagle et al 2012). Comparatively, WBM is less expensive, with less cost for cuttings disposal, and is environmentally safe to use in most regions of the world.

This paper presents a successful case study of drilling member (A) of a stratigraphic well that is composed of sticky shales with streaks of sandstone. Previous experience drilling this shale member (A) showed that a majority of washouts occur in this member because of shale sloughing, which leads to wellbore instability. The paper focuses on the formulation of an optimized inhibitive water-based fluid and its practical field application.

Experimental Evaluation

The experimental evaluation consisted of optimizing the high-performance water-based mud (HPWBM) for the stratigraphic well targeting member (A) composed of the sticky shales. The test fluids were mixed in stainless steel mixing cups on a five-spindle multi-mixer model 9B with a rotational speed of 11,500 RPM with sine-wave impeller blade No. 9B29X. The fluids were aged in high pressure/high temperature (HPHT) stainless steel ageing cells and hot rolled in a Model 705ES five-roller oven at 200 ^{o}F for 16 hours. The rheology of the fluids was determined at 120 ^{o}F on a 12-speed standard oilfield viscometer. The temperature was controlled with an electrically heated thermo cup. Rheology, fluid loss—

both API and HPHT—and retort testing were performed per API 13B1 Recommended Practice Standard Procedure for Field Testing Water-Based Drilling Fluids. **Table 1** shows the mixing order of products, the concentrations, and mixing time for the HPWBM.

The concentration of the products used to formulate the fluids was estimated with a proprietary numerical simulator. The rheology of the fluid was characterized in terms of plastic viscosity (PV), yield point (YP), and gel strength (GS). The YP is obtained from the Bingham-Plastic rheological model when extrapolated to a shear rate of zero. The PV represents the viscosity of a fluid when extrapolated to infinite shear rate. Both PV and YP were calculated with the 300-rpm and 600-rpm shear rate readings on a standard oilfield viscometer as given in Equations 1 and 2.

PV = 600 rpm reading – 300 rpm reading (1)

YP = 300 rpm reading – PV (2)

The GS was measured as the inflection point at 3 rpm after keeping the fluid static for 10 seconds and 10 minutes respectively in a thermo cup at 120 ^{o}F.

Because this was a stratigraphic well, little information was available on the clay composition of its member (A). Prior drilling experience on member A on other wells showed that a majority of washouts occur in this member because of sloughing of shales. A highly inhibitive WBM was needed to drill this well, so an optimised HPWBM was designed with the following products that provide improved shale stability and inhibition:

- High-molecular-weight polymer (HMW polymer) that prevents clay swelling and dispersion.
- Secondary Polymer (SP) that blocks clay hydration and prevents disintegration.
- Amine Stabilizer (AS) that reduces the dispersion and hydration of reactive clays by adsorbing at the clay pore openings. The plugging of the pores slows water transport into the shale.
- Secondary Stabilizer (SS) that provides inhibition and shale stabilization of the reactive shales..
- Poly-alkylene glycol (PAG) product to provide improved lubricity and shale stability. Other benefits associated with this product are the formation of a semipermeable micro-emulsion membrane, a more lubricous filter cake, and shale inhibition by encapsulation through glycol adsorption.

After a few lab trials, an 85 pcf formulation, Table 1, was finalized that met the programmed filtration and rheological properties of the well (**Table 2)**.

Field Evaluation

The vertical well to be drilled was a stratigraphic exploration well that could provide information on potential reservoirs and lithological information of the field. No offset data was available on the well and the nearest well information was 130 km away. Procuring cores from this stratigraphic well required drilling through reactive sticky shales in member (A). **Table 3** lists the interval parameters for drilling.

The objective was to drill a 12-in. hole section from 3,240 ft through member (A), to the casing point at a measured depth (MD) of 4,310 ft. A 9⅝-in. casing string was then to be run and cemented. The HPWBM optimized for member (A) was expected to provide maximum shale stabilization and inhibition to achieve maximum ROP without any incidents. An important success parameter for this drilling program was maintaining washout of less than 20%, i.e., the hole size is less than 14.4 in. The objective was to provide maximum wellbore stability for coring and logging operations without any hole instability or mud problems. The drilling program was executed within the program specifications and within the planned cost and time.

Initially the 13⅜-in. casing cement was drilled, followed by drilling 5 ft of member (A) formation at MD 3,240 ft with the previous section's KCl/polymer mud. A formation integrity test was then performed with this KCl/polymer mud with an equivalent mud weight of 105 pcf. The KCl/polymer mud was then displaced with the HPWBM with a density of 77 pcf per the mud program. After the HPWBM was circulated and conditioned, a bit trip was performed to run a polycrystalline diamond compact (PDC) bit. Drilling was performed without any problem until reaching MD 4,163 ft, where a gas zone was encountered. To control the gas flow, the mud weight was increased from 77 pcf to 83 pcf. While drilling, hole cleaning was performed every 30 ft with a high-viscosity sweep. Advanced hydraulics software was used to simulate the drilling process and optimize hole cleaning; the simulations showed the current parameters were optimum for drilling. However, the high-viscosity sweeps were continued as a precaution. **Figure 1** shows a graph from the simulation software of the drilling simulation for optimized hole cleaning**.**

The simulation was run at MD 3,630 ft with these operational parameters: flow rate of 600 gpm, ROP of 80 ft/hr and 50 rpm pipe rotation. The simulations show that the cutting loads percentage volume in the annulus was an average 1.33% volume, which was well below the maximum acceptable limit of less than 3% volume. A cuttings load greater than 3% volume signals inappropriate hole cleaning, which requires the drilling parameters to be reviewed.

Drilling time from 3,245 ft to 4,163 ft was about 28.5 hours. Between 4,163 ft to 4,193 ft, a coring job was performed and cores were cut with 96% recovery. The first coring job took 7.5 hours after which drilling was resumed to drill member (A) to 4,250 ft in 5.5 hours. A second coring job was performed between 4,250 ft to 4,310 ft; the second coring job took 15 hours with 100% recovery.

The interval was drilled in 6 days with 56.5 drilling hours on bottom, including the coring hours at an ROP of 18.9 ft/hr. The total drilling hours without the coring time was 34 hours at an ROP of 31.3 ft/hr. During drilling, six trips were performed — two bit trips, two coring trips, and two conditioning trips after coring. These trips encountered no tight spots. The optimized tripping speeds in and out were determined from surge and swab simulations performed with the advanced hydraulic software (**Figure 2)**.

The drilling torque was a maximum of 5000 ft-lbf while drilling through member (A) without any tight hole and/or hole instability problems.

After drilling, seven wireline logging runs were performed over a period of five days, per the planned program, without any problems. During the logging runs, two conditioning trips (wiper trips) were performed, which went smoothly without any tight spots or drag. Because of the perfect open hole stability provided with the HPWBM, no clean-out trip was performed after the last logging run and before running the casing, thereby saving 12 hours of tripping time. The 9⅝-in. casing was successfully run to bottom and cementing done per the planned program. No downhole losses or differential sticking was observed during drilling, tripping, or running of the casing and the cement job. **Figure 3** shows the caliper log of the 12-in. hole section in member (A).

The caliper log shows a hole size of 12.4 in., which indicates a 3.2% increase, well below the 20% washout limit (hole size of 14.4 in.) set as a success criteria for this drilling job. A total of 2,595 bbl of HPWBM was used to drill the 12-inch interval of member (A) composed of sticky shale. The dilution rate was 0.30 bbl/ft to avoid fluid dehydration and to maintain the fluid rheology. The concentrations of the specific shale inhibitors and stabilizers used in the HPWBM were maintained using hourly treatments based on the rate of penetration and test results.

Any calcium hardness was treated with soda ash and soda bicarbonate to maintain the calcium content below 200 mg/L. To remove fine solids and control the mud weight, a high-speed centrifuge was run at 2,000 rpm and a feed rate of 24 gpm. Three Derrick shakers were used to control and manage solids removal. The shakers were initially dressed with 3 x 80-mesh screen to 4,162 ft and subsequently changed to 3 x 150-mesh screen. The low-gravity solids content was kept below 5% by volume. Table 2 lists the actual values for the density, rheology, fluid loss and chloride content; 100% conformance with the programmed values was observed. The concentrations of the products used to drill the interval were similar to the laboratory formulations as shown in Table 1 and **Table 4**.

After coring, the team had a better understanding of the mineralogical composition of member (A) and its sticky character (**Table 5**).

The clay content of the shale was 57% weight with the majority being 34% weight illite/smectite mixed layer and 17% weight illite. The cation exchange capacity (CEC) was 14 meq/100 g. Assuming that the CEC contribution is from smectite alone, the total smectite content was approximately 18% weight smectite and 33% weight illite. Smectite is the swelling component and illite is the dispersive content present in the shale.

Conclusions

1. The HPWBM provided maximum shale inhibition and stabilization to drill member (A) of the stratigraphic well.
2. The 12-in. interval was drilled from 3,245 ft to 4,310 ft MD in 34 hours, with an ROP of 31.3 ft/hr. The total drilling time was 56.5 hr, with an average ROP of 18.9 ft/hr, which includes the coring hours.
3. The caliper logs showed only 3.2% hole size enlargement of the original hole size of 12 in. which met the success criteria of less than 20% washout, i.e., less than 14.4 inches.
4. Two cores were successfully cut from 4,163 ft to 4,193 ft and 4,250 ft to 4,310 ft with 96% and 100% recovery, respectively.
5. In total, eight trips and seven logging runs were performed without any tight hole, hole instability or mud problems. The optimized tripping in and out speeds were determined from surge and swab simulations performed with the advanced hydraulic software.
6. No downhole losses were observed during drilling, tripping, running the casing, and the cement job.
7. No cleanout trip (wiper trip) was performed after the last logging run and before running the 9⅝-in. casing because of the excellent hole conditions, which saved 12 hours of tripping time.
8. High-viscosity sweeps were pumped every 30 ft; drilling simulations with the advanced hydraulic software showed optimum hole cleaning that did not necessitate use of high-viscosity sweeps but they were run as a precaution.
9. The 12-in. section, including the troublesome member (A) shale, was drilled within the programmed drilling fluid specifications — density, rheology, fluid loss and chloride content—with 100 % conformance.

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Nomenclature

WBM = *Water-based mud*
HPWBM = *High-performance, water-based mud*
ROP = *Rate of penetration*
NPT = *Non-productive time*
YP = *Yield point lb/100ft*^{2}
PV = *Plastic viscosity cP*
HPHT = *High pressire high temperature*
pcf = *pound per cubic feet, lb/ft*^{3}

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Table 1—Lab Formulation of the HPWBM System

Products	Concentration in lb/bbl	
Water	255	
Na_2CO_3	0.25	
High temperature starch	6	
Organic Viscosifier	1	
HMW polymer	1.5	
Secondary Polymer (SP)	2	
Amine Stabilizer (AS)	4	
Poly-alkylene glycol (PAG)	10.6	
Secondary Stabilizer (SS)	9.52	
KOH	0.25	
Marble (fine)	5	
Marble Medium	15	
NaCl	80	
Barite	87	
	BHR	Hot roll for 16 hr
Plastic Viscosity	25	29
Yield Point	29	31
Mud Weight	85	
pH	10.16	
HPHT @200°F		6.8
Fann 600	79	89
Fann 300	54	60
Fann 200	43	48
Fann 100	27	34
Fann 6	5	7
Fann 3	3	5
GS 10 sec	4	7
GS 10 min	7	8
Chloride test mg/L		120,000

Table 2—Drilling Fluids Properties Programmed and Actual for Drilling Member (A) of the Stratigraphic Well

	Programmed	Actual
Density, lb/ft^3	80 – 85	77 – 83
PV, cp	25 – 30	19 – 28
YP, $lb/100\ ft^2$	25 – 30	25 – 27
Gel10 sec, $lb/100\ ft^2$	6 – 10	6 – 7
Gel 10 min, $lb/100\ ft^2$	8 – 12	8 – 9
API Filtrate, ml/30 mins	< 4	2 – 2.5
LGS, wt. %	< 5	2.6 – 3
pH	9.5 – 10	9.4 – 9.7
Chloride, mg/l	100 – 120 K	118 – 130 K

Table 3— Interval Well Parameters

Formation Type	Member A Composed of Sticky Shales
Top interval depth	3,245 feet
Bottom interval depth	4,310 feet
Interval Hole size	12 inches

Table 3— Interval Well Parameters	
Formation Type	**Member A Composed of Sticky Shales**
Fluid Type	High-performance water-based mud

Table 4—Concentration of the Products used to Drill the Member (A) Formation in the Stratigraphic Well

Product	Concentration lb/bbl
Barite	62.94
Secondary Stabilizer (SS)	3.65
HMW polymer	1.94
Secondary Polymer (SP)	2.07
Amine Stabilizer (AS)	3.3
Poly-alkylene glycol (PAG)	11.86
Marble (fine)	22.25
Marble (medium)	17.75
Polyanionic cellulose – Low viscosity	0.18
Polyanionic cellulose – High viscosity	0.43
High temperature starch	5.7
KOH	0.36
Na_2CO_3	0.38
$NaHCO_3$	0.21
NaCl	61.25
Organic Viscosifier	1.05

Table 5—Mineralogy of the Member A at 4,193 feet in the Stratigraphic Well

Quartz, wt%	17
Plagioclase Feldspar, wt %	2
Dolomite, wt %	trace
Siderite, wt %	5
Pyrite, wt %	19
Illite/smectite mixed layer, wt %	34
Illite, wt %	21
Kaolin, wt %	2
Chlorite, wt %	trace
CEC, meq/100 g	14

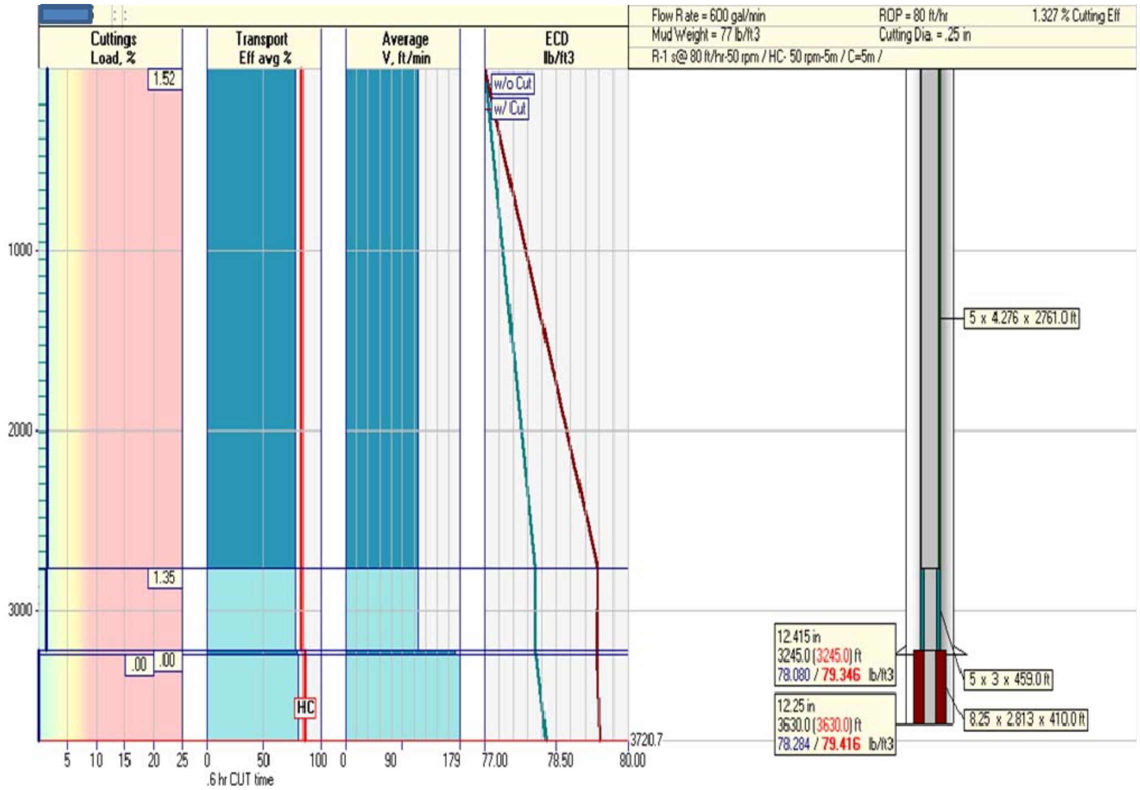

Fig. 1—Graph of the drilling simulation to determine optimum hole cleaning parameters with the advanced hydraulics software.

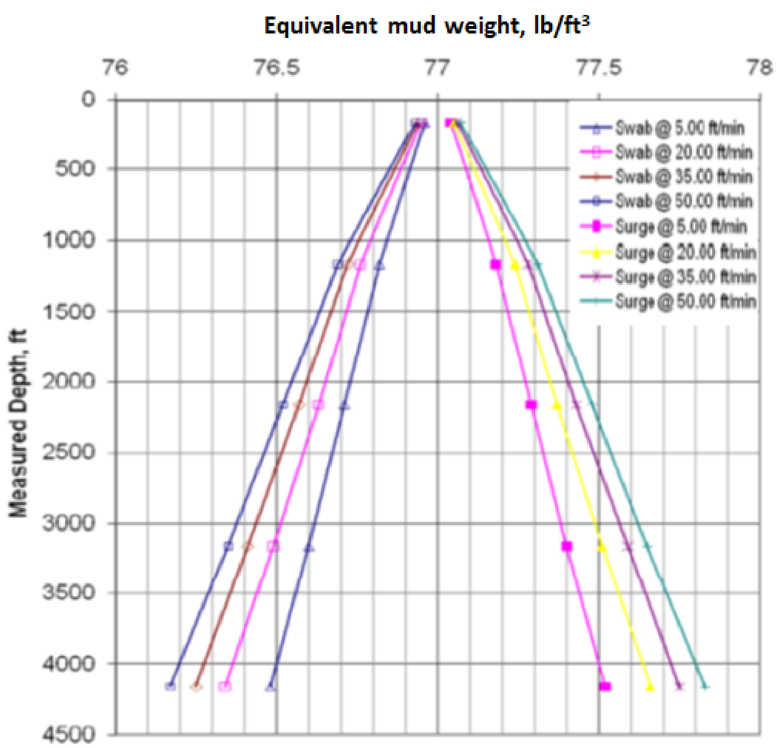

Fig. 2—Graph from advanced hydraulics software showing surge and swab pressures used to determine optimum tripping speeds in and out of the hole.

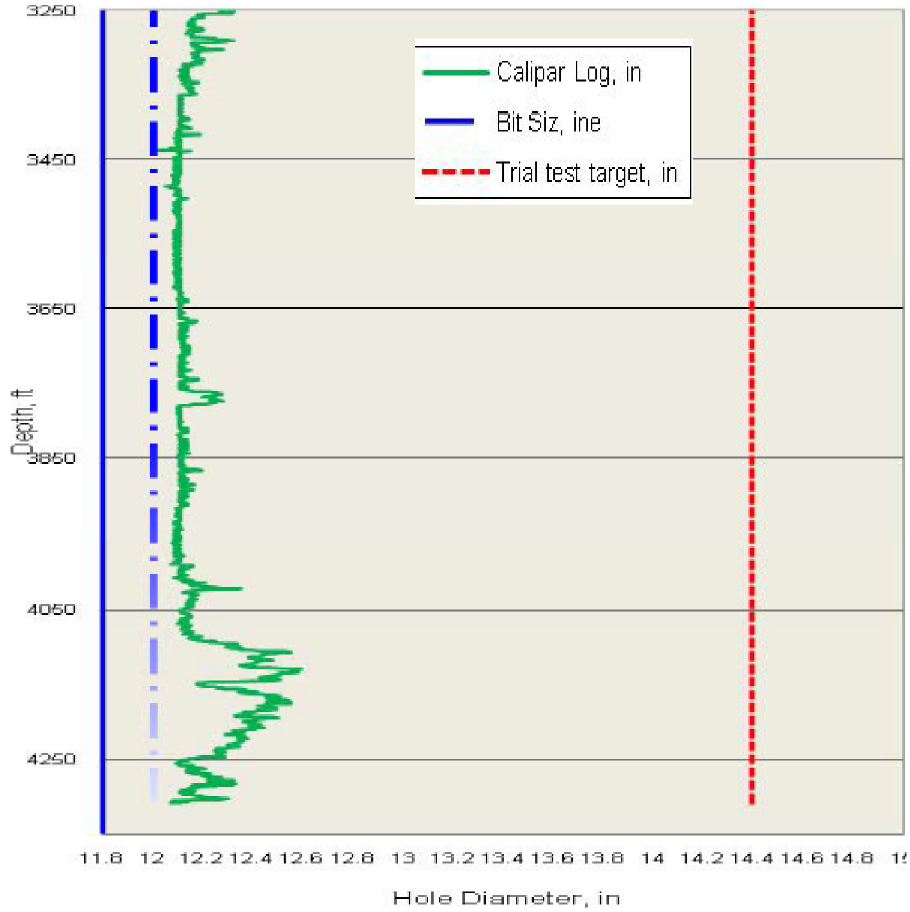

Fig. 3—Caliper log of 12" section of the member (A) in the stratigraphic well drilled with the HPWBM.