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First Application of New Polymer Viscosifier with a Non-Damaging Drill-in Fluid

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Abstract

Achieving adequate hole cleaning is one of the greatest concerns while drilling deviated wells. Optimal flow regimes and cuttings removal efficiencies are dependent upon the well profile. Since a cutting originating in the deviated section of a well has to travel through the horizontal and vertical intervals, its removal is best achieved by optimizing the rheological properties of the drilling fluid. Often times horizontal wells are open hole completions, which have increased susceptibility to formation damage, leading to reduced production.

Generally, polymeric additives are used in drilling fluids for imparting desirable rheological properties and filtration control capabilities. The polymers selected for use in reservoir drill-in fluids are even more specialized, as they should not render damage to the target production formations and should be easily removed during the well completion process.

This paper demonstrates the benefits of employing an optimal rheology profile in the field application of a non-damaging, drill-in fluid. The application of a new polymer technology is analyzed in terms of well productivity and by the polymer's effect on the rate of penetration, pump pressures, quantitative cuttings transport, and other measureable parameters, relative to that of fluids formulated with conventional viscosifiers.

Introduction

A wide number of polymers have found use in a range of applications within the oil industry.[1] Their areas of application include drilling and completion, production enhancement, cementing, lost circulation, wellbore displacement operations, and in solving flow assurance challenges such as hydrate and scale control.[6]

In drilling and completion operations, the use of polymers is important for achieving the viscosity and rheology profiles required to address an assortment of reservoir conditions. Well geometry and increasing depths can greatly challenge the performance of existing polymer offerings used in both of these fluid types. Field practices and experimental observations have shown that under certain conditions, smaller cuttings are more challenging to transport out of the deviated hole. Enhancing the performance of polymers in their small-particle transporting capabilities is an increasing necessity for effective wellbore cleanup and a focus of our works.[6]

Drilling Fluid Requirements

Based on environmental and cost considerations, water-based muds (WBM) offer attributes that are generally preferred over their oil-based mud (OBM) counterparts. With the exception of certain classes of synthetic polymers, most of the naturally-derived polymers used in WBMs often exhibit inferior performances to OBMs in higher temperature applications. More specifically, the water-soluble polymers commonly used in WBMs fail to maintain the required solution rheology to meet the demanding requirements of these modern wells. To advance the current use of WBMs, new or modified biopolymers are needed to extend the rheological properties of commonly used polysaccharides such as hydroxyethyl cellulose (HEC), xanthan, and scleroglucan.[2]

Biopolymers, when properly chosen, can provide rheological properties that are critical to formulate effective WBMs. These include viscosity enhancement and viscosity retention at downhole temperatures, the suspension and removal of cuttings, as well as providing effective filtration control. In situations where drilling operations may be suspended, the additional attributes of elasticity and yield stress are important in preventing solid deposition and avoiding the worst case scenario of packing off the bottomhole assembly.

In addition to rheological considerations, polymeric additives in WBMs can fulfill other needs and requirements. First, they should not cause permeability damage by forming persistent filter cakes. Some prominent biopolymers are often contaminated with proteins and/or cellular debris that are difficult to remove after completion. They can penetrate the pore spaces of the formation leading to reduced permeability and lower production. Second, biopolymers can influence the sensitivity of the WBMs toward reactive shale formations, in some cases mitigating or preventing water removal from clay materials. Third, biopolymers that can function effectively in a range of different brines and over a wide range of temperatures are preferred. Salts can be added to WBMs for density control and for the adjustment of water activity. Good polymer-brine compatibility is needed in order to achieve desirable flexibility in formulation design.

One of the more commonly used biopolymers in drilling applications is xanthan gum, which has molecular chains that interlock to give its solutions a gel-like consistency. This network of chains can effectively suspend solid particulate matter, maintaining some viscoelastic properties at low shear rates. Xanthan also performs in water as well as several brines. These features allow for greater flexibility in designing formulations to optimize cost, density and rheological properties which in turn can ultimately meet the demands of the various temperature and pressure conditions encountered. However, the use of xanthan is limited by deterioration at higher temperatures (especially in divalent brines), and can result in lower return permeability and limited rheology at lower shear rates.[6]

A biopolymer that meets many of the stated requirements, while surpassing the temperature limits of currently available materials, was recently introduced to the oilfield through the collaborative efforts of Dow Chemical Company and a major drilling fluids provider. One of the promising chemistries investigated has been commercialized and is referred to here as Polymer A.[6]

Description of Polymer A

Numerous biopolymer derivatives that might provide the necessary rheological properties were initially screened. After laboratory investigations in a variety of brines, the new Polymer A was shown to exhibit excellent performance in freshwater as well as sodium bromide, calcium chloride, calcium bromide and zinc bromide brines. Specifically, high throughput methodology was used to prepare and analyze the rheological properties of xanthan and Polymer A.[3]

Polymer A functions primarily as a viscosifier for water - based and brine-based systems. After extensive laboratory testing it was found that the product offers unique rheological characteristics, superior ability to build gel structure, and exceptional suspension characteristics. All these features provide enhanced ability to clean the hole, which is especially beneficial for drilling extended deviated sections.[6]

Secondary functions of the Polymer A include: improved fluid loss, shale inhibition, and better acid degradability. Polymer A is a more acid soluble product compared to many biopolymers. This is beneficial for low bottomhole temperature acid treatments where other polymers may cause formation damage.

In the final research investigation step, return permeability testing showed the favorable result of 92% return permeability. To finalize the research on the product, a field trial was performed in order to compare well productivity and performance of Polymer A with fluids using conventional viscosifiers, like xanthan gum, HEC, CMC, etc. To do this, we replaced the viscosifier currently used in this field with Polymer A, and then compared the productivity of the selected wells.

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Field Case Study

Polymer A was first applied in the field by a major Russian operator while drilling through a mature limestone reservoir utilizing non-damaging water-based drill-in fluid in Novo-Elshovskoe field, near South Ural. The Novo-Elshov field is a complex, low permeable limestone reservoir with naturally fractured cavernous/vugular formations that cause severe or even total fluid losses in many drilling operations. The typical loss rate is difficult to predict in the field and could vary from $7m^3$/hour up to total losses. Bridging the thief zone is challenging. Planning and establishing a strategy prior to drilling a potential thief zone is critical for preventing and controlling fluid loss. It is a common practice in the Tatarstan region to use water-based drilling fluid and to pump lost circulation pills or cement plugs in case losses occur.

In order to overcome common regional challenges when using water-based systems that include high water production, high skin, poor cement/formation bond, and poor cutting removal, the operator decided to use a high-performance non-damaging drill-in system. The detailed list of expected issues in the reservoir section of the trial well is displayed in the **Table 1**. Only acid-soluble and formation-friendly fluid additives were used in the payzone interval. Only brine and sized $CaCO_3$ were used as fluid weighting agents. Bridging the payzone to minimize fluids and solids invasion is the key to successfully prevent formation damage. In order to achieve that, sized $CaCO_3$ was used as a bridging material. The $CaCO_3$ particle size distribution is based on mean (D50) particle size and the fluid formulation is based on geological and formation mineralogy data obtained from the client.

Table 1 Issues Related to Reservoir Section

Hole Size mm (inch)	Fluid Density kg/m^3 (ppg)	Fluid Type	Possible Issues
215,9 (8-1/2)	1080 (9.0)	Polymer System	Differential sticking Filtration control Wellbore cleaning Wellbore stability Lost circulation Increase in LGS Formation fluid influx

The section was drilled successfully to total depth, then subsequently cased and cemented. Continued monitoring indicated that the production index for the trial well was exceeded by 30% (when compared to the nearby wells that used conventional viscosifiers). In addition, subsequent improvement in cement-formation bond was achieved compared to the upper section of the trial well.

Interval Summary

The experimental Polymer A product, a new viscosifier for water and brine based fluids was used to drill through the 215.9 mm (8-1/2 in) payzone interval. Detailed information on the wellbore geometry will be represented in hydraulics section of the paper. During the field trial, fluid engineering support was provided for drilling fluids preparation and maintenance. Strengths and weaknesses of the Polymer A system were reported and discussed with the operator.

1. **Strengths of Polymer A System:** The Polymer A system minimized problems associated with hole cleaning and bit balling and maintained good wellbore

stability. The Polymer A system provided a thin filter cake, gauge hole, resistance to bacteria, and improved rate of penetration. System maintenance was uncomplicated.

2. **Weaknesses of the Polymer A System:** Initial fluid mixing was a challenge due to lack of appropriate fluid preparation equipment (hopper) on the location. Some foaming tendency and fish eyes were observed during the fluid preparation, but this was not an issue during the drilling. Due to the initial low solids content in the system, the filter cake formed was thin, but not firm. During the logging trip, a formation water influx occurred. As a result of the formation water contamination, the low RPM rheology and YP decreased, while the density and salinity of the fluid increased. The fluid system was diluted with fresh water and treated with a polymer. Composition of the formation water is not available at this time.

Recommended fluid properties are presented in **Table 2** and recommended fluids formulation is illustrated in **Table 3**. Routine fluid checks were performed twice per day and are described in the Drilling Fluid Reports. Necessary drilling fluid treatment and dilution were applied on a daily basis. Expected regional challenges, such as severe fluid losses were resolved with appropriate lost circulation materials suitable for the upper hole and payzone applications.

Table 2. Recommended Fluid Properties

SG	1.08
FV, sec/quart	45-60
PV, cP	Minimum
YP, lb/100ft^2	15-22
6 RPM	>6
Gel, 10 sec/10 min, lb/100ft^2	3-7/6-15
API, Filtrate, ml/30 min	6-8
pH	8,5-10
Ca^{++}, mg/l	<600
MBT, kg/m^3	<28
Sand, % vol.	<1.0

Table 3. Recommended Mud Formulation

Product	Initial (kg/м^3)	Final (kg/м^3)
Caustic Soda	1	3
Soda Ash	1	2
Bactericide	0.50	1
POLYMER A	1.5	3
PAC LE	1	2
Modified Starch	7	10
Lubricant	3	5
Sized CaCO3, 5 micron		30
Sized CaCO3, 50 micron		60

Breaker System Treatment

An acid generating, delayed-reaction filter cake breaker system was proposed for the treatment of the reservoir section, and from here on will be simply referred to as breaker. The breaker system dissolves calcium carbonate and is able to dissolve or disintegrate polymers/starches deposited on the wellbore face. The breaker system does not have the immediate aggressive reaction associated with conventional acid treatments such as HCl, but as result of hydrolysis reaction, generates acid under controlled in-situ condition. The delay in reaction time helps ensure even distribution of breaker fluid across the open hole before the removal reaction begins.

Table 4 shows the formulation of the breaker treatment. In order to spot the breaker in the zone of the interest, a high viscosity pill was spotted before and after the breaker blend. In order to minimize water production and water-wetting of the formation, an appropriate surfactant was incorporated into the breaker formulation.

Table 4. Breaker Treatment Formulation

Product	Description	Concentration, % vol.
KCl	Carrier Fluid	To SG-1.02
Sodium Bicarbonate	pH control	As needed
Filtercake Breaker	Acid Precursor	18
Water-wetting surfactant	Surfactant	0.2
Polymer	Viscosifier	As needed for Hi-Vis pills

Drilling Fluid Preparation

A fluid mixing system capacity on the rig was limited to a 4-m^3 pre-mixing tank and two 20-m^3 mud pits. In order to prepare for displacement, the fluid mixing and storage facility was setup to meet operational requirements. Using nominal 4-m^3 mixing units mounted in the tank, the fluid batch was transferred into a main circulation tank. Each tank was equipped with agitation in order to prevent solids settling. The mix water composition also offered a means to design a fluid system to suit a particular application. Fresh water solutions provide the fastest polymer hydration times. Brines are able to decrease reaction rates in some cases. The fresh water analysis was performed at the wellsite and is presented in **Table 5**. Fluid properties are extracted from daily fluid report also illustrated in **Table 6**.

Table 5. Field Water Analysis

SG	1
pH	7.5
Ca++	180
Cl-	1000

Table 6. Initial Fluid Formulation. Products are listed in the order of addition.

Product	Concentration
POLYMER A	1.2 ppb
Modified Starch	3.4 ppb
Soda Ash	0.3 ppb
Defoamer	0.2 ppb
Biocide	0.1 ppb
BARACARB® 50	10 ppb
BARACARB® 150	10 ppb

Table 7. Initial Fluid Properties.

Density, SG	1.08
pH	7.5
Chlorides, mg/l	1000
API Filtrate, ml/30min	7.5
Rheology°F	120
600 rpm reading	37
300 rpm reading	28
200 rpm reading	22
100 rpm reading	18
6 rpm reading	6
3 pm reading	5
Plastic Viscosity, cP	9
Yield Point, lb/100 ft^2	19
10 sec Gel, lb/100 ft^2	5
10 min Gel, lb/100 ft^2	8

Breaker System Preparation

Commonly filter-cake residue is removed by displacing the open-hole section with a clean up fluid (often referred to as a breaker system) that attacks the filter-cake. The breaker system can provide effective, uniform filter cake removal in sandstone and carbonate formations. Since the novel breaker system is an acid precursor, it is safer for personnel and equipment than conventional mineral acid breakers. The breaker system does not require special acid resistant tanks or equipment and was mixed on the location in the 4-m^3 pre-mixing tank.

To prepare the breaker system, 3.5 m^3 breaker fluid and 3 m^3 high-vis pill were premixed in separate tanks. The appropriate low pump rate was used to spot the breaker into the perforated zone in the following sequence:

1.5 m^3 high viscosity pill,
3.5 m^3 breaker,
1.5 m^3 high viscosity pill.

After pulling out of the hole to 250 m TVD, the pill was allowed to soak for 24 hours. The crew then tripped in the hole and displaced with 1.02 SG KCl.

Hydraulics

The drilling fluids hydraulics report and associated graphics (**Figures 1-3**) illustrate accurate hydraulics modeling. This tool is designed to help the user to simulate proposed drilling conditions, allowing optimization of not only the fluid properties but also the drilling parameters. Accurate modeling allows the user to look ahead of the bit, avoid future problems and reduce NPT. In deviated wells, cuttings transport mechanisms are significantly different from vertical wells. In an inclined well, two kinds of transport mechanisms have been identified for the efficient removal of cuttings:

- minimum fluid velocity that needed for cuttings removal
- fluid rheology for cuttings suspension

Accordingly, drilling fluids hydraulic simulation software is designed to describe the minimum fluid velocity required to effectively clean the hole and incorporates fluid rheology into the hydraulics calculation. Output from drilling simulations focuses on annular cuttings concentrations, including average cuttings concentration as well as localized cuttings distribution in the annulus, and equivalent circulating density (ECD). Only actual field data was used for inputs for the software simulation. Input data for hydraulic software simulation are presented in **Tables 8-10.**

Table 8. Hole Geometry

Hole ID	Depth	TVD	Description
mm	m	m	
227.9	300	300	Conductor
215.9	940	905	Open Hole

Table 9. Pipe Geometry

OD	ID	Length	Description
mm	mm	m	
127	90	890	Drill Pipe
178	80	50	Drill Collars

Table 10. Drilling Properties

Flow Rate	1860 l/min
Suction Temperature	27 C
Flow Line Temperature	30 C
ROP	4 m/hr
RPM	70 m/hr
Cutting Diameter	5 cm
Running Speed	80 m/min

Typical recommended maximum cutting concentration in the wellbore is 4 percent. According to hydraulic simulation, the cutting load increased to 0.21 percent in the deviated portion of the well (**Figure 2**) when compared to 0.15 percent in open hole section and 0.14 percent in the conductor (vertical section of the well). Cuttings transport efficiency was 75 percent in the open hole section and reduced to the 60 % in the deviated critical section. Software algorithm incorporates average fluid velocity (AV) in the simulation. As expected, the maximum AV was 159 m/min in the open hole section, reduced gradually to 79 m/min in the deviated section, and 60 m/min in conductor. The differences in the annular fluid velocity are based to the wellbore geometry.

The results of hydraulic software modeling were critical to the operator in order to overcome the field challenges with very narrow margins between pore pressure (PP) and fracture gradient (FG). Using the Polymer A system effective hole cleaning was achieved at critical thirty degree hole angle.

Cementing

In the past, the operator suffered with insufficient cement bond. Cement bond quality is imperative for all phases in the life of a well. Achieving a superior cement bond can be an engineering challenge in areas with naturally fractured formations. Crossflows behind casing reduced the cost effectiveness of the well. The crossflows resulted in fluid and gas migrations behind casing and between zones. Analysis of all cement bond logs is based on “known” cement compressive strength using a nomograph that measures cement compressive strength on a sheath thickness of ¾ inches of uncontaminated cement.

The cement bond log presented in **Figure 4** illustrates the production interval of the well. The significant improvement in ability of the casing-cement system to maintain a seal at the cement-to-formation interface was achieved due to inhibitive properties and excellent acid degradability of Polymer A. Polymer A was able to enhance fluid-loss control, create a stable gauge hole, allow for resistance to bacteria and create an acid degradable filter-cake that was easily removed from the wellbore face with a cement acid pre-flush. This resulted in an improved displacement of drilling muds by cement slurries. Cement placements in the region were historically done by pumping acid pre-flush ahead of the cement slurry. No adjustments have been made in cementing practices on the trial well.

Conclusions

The trial well was drilled successfully to TD and subsequently cased and cemented. The Polymer A system minimized problems associated with hole cleaning and bit balling, and maintained good wellbore stability. The Polymer A system provided a thin filter cake, gauge hole, resistance to bacteria, and improved rate of penetration over previously drilled wells. The optimized fluid system helped the client to overcome the greatest operational challenge of the field which is poor cement bond. Polymer A was helped to build thin low permeable fitercake that was easily removed with the breaker treatment at low reservoir temperature. Drilling fluid system maintenance was not complicated and was easily managed. Production of the trial well was increased by 30% compared to the offset wells.

References

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6. Poindexter, M., Kuhlman, R., Mohler, C., and Collins, N.: “Extending the Application of Biopolymers for Water-Based Muds.” [Pending Article]. - 2011.

Figures

Figure 1. Wellbore Geometry

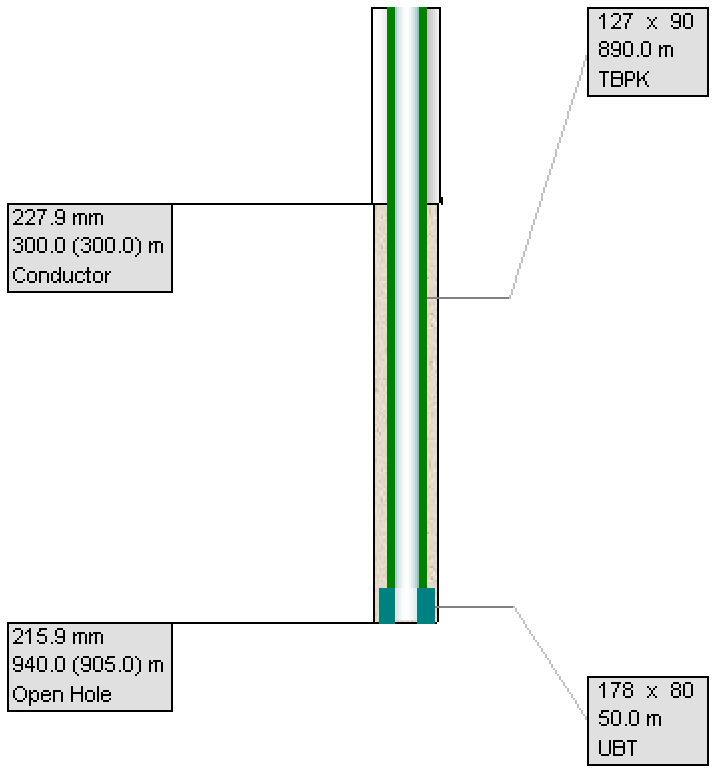

Figure 2. Wellbore Inclination

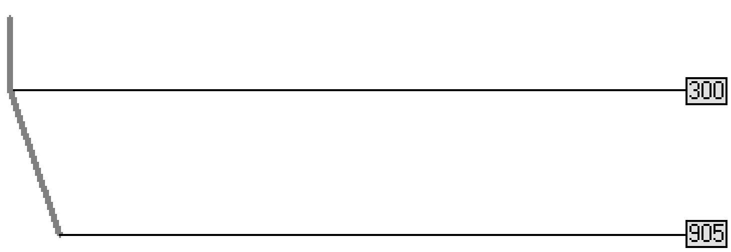

Figure 3. Hydraulics Modeling Results

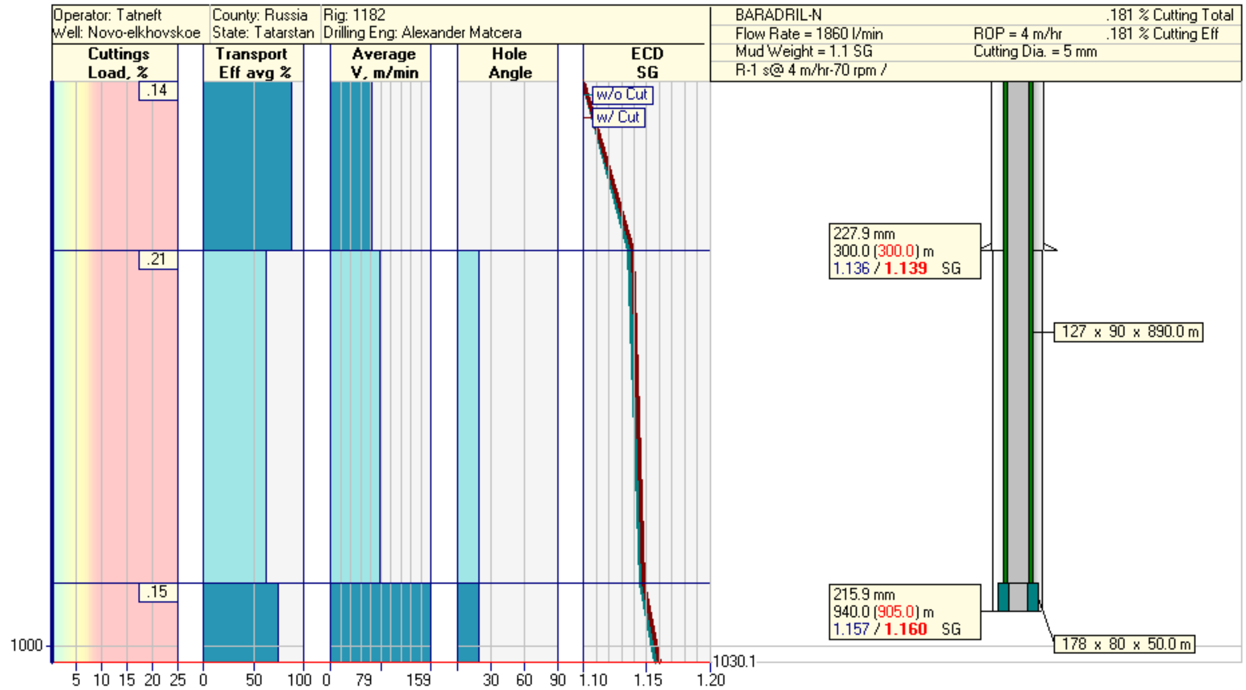
Operator: Tatneft
Well: Novo-elkhovskoe
County: Russia
State: Tatarstan
Rig: 1182
Drilling Eng: Alexander Matcera
BARADRIL-N
.181 % Cutting Total
Flow Rate = 1860 l/min
ROP = 4 m/hr
.181 % Cutting Eff
Mud Weight = 1.1 SG
Cutting Dia. = 5 mm
R-1 s@ 4 m/hr-70 rpm /
Cuttings Load, %
Transport Eff avg %
Average V, m/min
Hole Angle
ECD SG
.14
.21
.15
w/o Cut
w/ Cut
227.9 mm
300.0 (300.0) m
1.136 / 1.139 SG
127 x 90 x 890.0 m
215.9 mm
940.0 (905.0) m
1.157 / 1.160 SG
178 x 80 x 50.0 m
1000
1030.1
5 10 15 20 25 0 50 100 0 79 159 30 60 90 1.10 1.15 1.20

Figure 4. Cement log illustrating excellent bond below 900 meters.