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# Novel Biopolymer Decreases Formation Damage for Water-Based Drill-In Fluids

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## Abstract

Drilling operations using water-based fluids (WBF) is environmentally convenient for certain fields around the world. However, for very reactive formations, WBF could be detrimental due to incompatibilities, creating challenging drilling operations and negatively influence production. WBF must be inhibited for clay/shale interaction and corrosion, very lubricious, with minimal filtrate invasion. If a WBF is used to drill reservoirs, the design complexity increases aiming negligeable reservoir damage and compatible with formation fluids.

Polymers such as xanthan gum (XG) are used to formulate WBF; it provides viscosity and carrying capacity. The damage caused by the XG could be removed using breakers, but extra steps aren't always desirable by operators. Therefore, a new biopolymer was created to replace the XG aiming to decrease damage and remove the need for a breaker.

WBF were formulated using XG or the novel biopolymer. The fluids were subjected to several tests including rheology, fluid loss, accretion, shale-particle disintegration, and return permeability. All with the goal of predicting compatibility with the reservoir and behavior while drilling the reservoir section.

The two WBF were tested side by side. The novel biopolymer is capable of creating viscosity and carrying capacity similar to XG. When the novel biopolymer is used to formulate the fluid, return permeability in limestone cores for producers increases from 55.7% to 89.7% and the filtrate invasion inside the core decreases from 79% to 29%. Lift off pressures were below 10 psi for both fluids and no differences were observed when accretion (<1%) and shale-particle disintegration (>90%) tests were performed using London and Nahr Umr clay.

Nevertheless, the interaction between all WBF components must be studied carefully. Synergistic effects must be considered when formulating the fluid. Inhibitors such as clay, oxygen, and corrosion could impact the filtrate interaction with the near wellbore in the reservoir and change the return permeability results. Novel biopolymers used to formulate WBF decreases damage to the formation while maintaining synergistic effects with other components. The result is a less damaging fluid to reservoir with improved capacities.

## Introduction

Increased demand for hydrocarbon causes the wells to be drilled extended reach horizontal (>20,000 ft) to have more hydrocarbon recovery with limited drilling of new wells to save money and time. Due to such extended reach horizontal section, possibility of breakers usage will become a challenge particularly in limestone reservoirs as the breakers cannot remediate the damage caused. To this reason, the key objective of the components used in the drill-in fluid formulation should help in minimizing the formation damage cause to the wellbore and limit the fluid invasion to help maintain the wellbore stability. The damage caused to the formation can be of different types that include filtrate invasion, filter cake (internal and external), and wettability change of the reservoir due to the drilling fluid type used. Formation damage and native fluids production impediment depends on the mineral reservoir composition, its sensitivity to filtration ratio and filtrate composition depending on drill-in fluid water base fluid salinity and alkalinity, and its interaction with other components such as lubricants (Pietrangeli 2024).

In addition to the type of bridging material, the size is important to ensure minimal filtrate invasion into the reservoir. It has been well established that the particle size distribution (PSD) must be carefully targeted for the pore size and permeability of the reservoir (Abrams, 1977 and Vickers et al., 2006). Micronized materials skew the PSD much smaller, so it was important for this project to adjust with larger size particles in these fluids.

The damage caused by the drill-in fluid could be quantified through oil return permeability measurements and flow-initiation pressures performed to an analogue core at relevant flow rates for oil producer wells (Ding et al. 2002). Productivity losses are especially critical for long horizontal wells which are often completed as an open hole. If damage is produced, it cannot be bypassed by perforations and may lead to large skin factors.

Over the past several decades, typical water-based drill-in fluid formulations have relied on a minimal set of products: brine as the base fluid, dispersed xanthan gum as the viscosifier, regular or cross-linked starch as the fluid-loss control agent, and calcium carbonate as the bridging material, along with additives for alkalinity and hardness. Very limited research has focused on finding alternatives for these components —particularly xanthan gum and starch—because of their highly versatile nature. These polymers are compatible with most, if not all, completion brines, offer long viscosity life, require practical concentrations, are widely available, naturally degradable, thermally stable, environmentally friendly, and cost-effective.

Xanthan gum is a widely used viscosifier in drill-in fluids due to its exceptional rheological properties, environmental compatibility, and biodegradability. Despite its known potential to cause minor formation damage primarily through filter cake buildup and temporary permeability reduction, its impact is significantly less severe than that of many synthetic polymers. The extent of this damage is generally less significant compared to other commonly used fluid additives. Despite ongoing efforts, numerous studies have explored alternatives such as guar gum, hydrophobically associating polymers (HAPAM), and nanoparticle-enhanced composites, yet none have consistently matched xanthan gum's performance. No developed alternative products such as modified xanthan derivatives, starch-based agents, and other biopolymers have consistently matched xanthan gum's performance across diverse drilling environment reservoir conditions. This unmatched versatility makes xanthan gum a dominant in the market, effectively maintaining a monopoly in its application within the oilfield services sector. Market forecasts project the oil drilling grade xanthan gum sector to grow by 20% in the next 5 to 10 years driven by offshore exploration, enhanced oil recovery (EOR) techniques, and regulatory shifts favoring biodegradable additives. Consequently, while the search for viable substitutes continues, xanthan gum remains the industry standard for drill-in fluid formulations.

This paper presents a laboratory investigation into a newly developed biopolymer designed for drill-in fluid (DIF) applications. The biopolymer was engineered to integrate the advantageous properties of both xanthan gum and starch commonly used as viscosifiers and fluid loss control agents without compromising their individual performance. The formulation aims to enhance rheological stability while significantly reducing formation damage typically associated with conventional biopolymer systems. Notably, the new biopolymer demonstrates improved cleanup characteristics, and in certain reservoir conditions, it eliminates the need for enzymatic or chemical breakers, thereby simplifying the completion process and reducing operational costs.

## Fluids Designing Parameters

To address the operational challenges associated with drilling the 12.25 in. and 8.5 in. hole sections, the customer requested the development of a versatile drilling fluid system with specific capabilities. For the 12.25 in. section, the fluid must provide strong inhibition against problematic shales to ensure wellbore stability and minimize issues related to reactive shales. For the 8.5 in. reservoir section, the same fluid system —after dilution—should be suitable for drilling through a fractured carbonate and dolomite reservoir, with a focus on minimizing formation damage and achieving high return permeability. To validate performance, the selected fluid system must undergo laboratory testing to confirm its suitability for both sections. The most important tests for the customer were shale interaction, fluid loss using permeability plugging apparatus, and return permeability, which aim to demonstrate the fluid's ability to maintain formation integrity while optimizing reservoir productivity. The fluid design requirements specified by the customer are presented in Table 1.

**Table 1—Fluids specification per customer request.**

| Test Parameter | Units | Value |
|---|---|---|
| Mud Weight | lbm/gal | 10.6 |
| pH | - | 10.0 – 10.5 |
| Plastic Viscosity (PV) | cP | As low as possible |
| 6 RPM | Dial reading | 12 – 15 |
| API Fluid Loss – 30 min | $cm^3$ | ≤ 5.0 |
| HTHP fluid loss @250°F, 500 psi, 30 min on paper | $cm^3$ | ≤ 15.0 |
| PPA fluid loss @150°F, 500 psi, 4 hours on disc | $cm^3$ | ≤ 15.0 |
| Shale-particle disintegration | % | > 95.0 |
| Accretion tests | % | < 2.0 |
| Return permeability @140°F | % | > 80.0 |

## Laboratory Test Procedures

The fluids were formulated and characterized following the API-13B-1 and API-13I standards. Some of the testing included density, pH, fluid loss, rheological profile, lubricity, shale-particle disintegration test, shale accretion tests, and return permeability test.

***Fluid blending and preparation.*** All fluids were prepared following the API 13B-1 and 13I recommended practice. The fluids were mixed under control temperature baths to avoid evaporation of fluids, using a Silverson mixer L5 at 5,000 RPM for a total of one hour, and aged for 16 hour at 130°F and 100 psi.

***Rheology Profile.*** The rheology profile was determined by using an OFITE 900 viscometer at 120°F. Plastic viscosity (PV), yield point (YP), and gels were determined for all the fluids.

***Fluid Loss.*** Several techniques were used to determine the fluid loss of each fluid: (1) API filtrate as described in API 13B-1 at room temperature and 100 psi for 30 min, (2) HPHT filtrate on paper as described in API 13B-1 at 250°F and 500 psi differential pressure, and (3) permeability plugging apparatus (PPA) test to determine the fluid loss on aloxite disc of 10 µm after 30 minutes and four hours at 150°F and 500 psi differential pressure.

***Metal-to-Metal coefficient of friction - Lubricity.*** OFITE lubricity tester was used to determine metal-to-metal coefficient of friction (CoF) at room temperature.

***Shale-Particle Disintegration Test.*** Shale dispersion tests were conducted to evaluate the inhibition performance of the drilling fluids using shale cuttings sourced from Nahr Umr clay and London clay following API-13I recommended practice. Composition of the shale samples used during testing was determined using X-Ray Diffraction technique and shown in Table 2. Each shale sample is very reactive and sensitive.

**Table 2—Nahr Umr shale and London clay characterization by X-Ray Diffraction.**

| Mineralogy | Nahr Umr Shale | London Clay |
|---|---|---|
| Quartz | 12 | 58 |
| Plagioclase | - | 9 |
| Dolomite | - | 4 |
| Siderite | - | 3 |
| Feldspars | - | 7 |
| Calcite | 8 | - |
| Halite | 1 | - |
| Hematite | 13 | - |
| Illite | 8 | 9 |
| Mixed Layer* | 2 | 5 |
| Kaolinite | 55 | 2 |
| Chlorite | 1 | 3 |
| *Percent Expandable in Mixed Layer | 10 – 30 | 25 – 50 |

Each test utilized 20 grams of shale cuttings, sized between 5–10 mesh, which were mixed with the respective drilling fluid and subjected to hot-rolling in a roller oven at 130°F for 16 hours to simulate downhole conditions. After the hot-rolling period, the samples were cooled and screened through a 35-mesh sieve to separate undispersed shale from the fluid. The retained shale was thoroughly washed to remove residual drilling fluid solids, then dried and weighed. The percentage of shale retained was calculated to quantify the dispersion resistance of each fluid system. Su et al in 2025 defined Nahr Umr shale as a Class 2 - plastic shale highly laminated, anisotropic, clay-rich unit primarily composed of kaolinite, illite-smectite, and chlorite, and high reactivity to water-based mud.

***Shale Accretion Test.*** Shale accretion tests were conducted to evaluate the tendency of drilling fluids to promote shale adhesion under dynamic conditions. The tests utilized 20 grams of shale cuttings, sourced from Nahr Umr shale and London clay, and sized between 2–4 mm. Please see Table 2 for shale composition. The shale cuttings, along with a steel bar, were placed in a hot rolling cell containing the drilling fluid and subjected to hot-rolling at 130°F for 30 minutes to simulate downhole mechanical interaction. After cooling, the steel bar was removed, cleaned, and weighed to determine the amount of shale accreted.

***Return Permeability Test (testing methodology 1 and testing methodology 2).*** Indiana limestone was selected as the analogue core plug material for return permeability testing due to its consistent petrophysical properties, including a relative permeability to brine ranging from 15 to 20 md and a porosity between 15% and 18%. Synthetic formation brine was used as the saturating fluid, while LVT-200 served as the permeating fluid throughout the tests. Prior to testing, all core plug samples were evacuated of air and pressure-saturated with synthetic brine. Initial water saturation was achieved by spinning the samples in an air-displacing brine centrifuge at 200 psi capillary pressure for four hours. Following centrifugation, the samples were briefly vacuum-saturated with the permeating fluid.

Each core plug was subjected to a net confining stress of 3,000 psi and a pore pressure of 500 psi using the permeating fluid. The system temperature was elevated to 140°F, and effective permeability to the permeating fluid at initial water saturation was determined using two flow rate protocols:

- Testing methodology 1 ❼ Flow rates of permeating fluid 2, 4, 6, and 2 $cm^3$/min
- Testing methodology 2 ❼ Flow rates of permeating fluid 2, 1.5, 1, 0.75, and/or 0.5 $cm^3$/min.

After baseline permeability was established, the drill-in fluid was circulated across the core face at an overbalance pressure of 500 psi and a flow rate of 10 $cm^3$/min for 10 minutes. This was followed by a reduced flow of 4 $cm^3$/min for 50 minutes and a final soak at 0.5 $cm^3$/min for three hours. Leak-off volumes were monitored throughout the process, and the fluid was left to statically soak overnight for 12 hours under the same overbalance pressure.

To simulate cleanup, permeating fluid was circulated across the core inlet face at 30 $cm^3$/min for 30 minutes. Subsequently, liftoff pressure was determined by injecting permeating fluid from the reservoir side at a low flow rate of 0.25 $cm^3$/min in the production direction. Once flow equilibrium was reached, regain effective permeability at residual fluid saturation was measured using the same flow rates as in the initial permeability test. To assess the impact of filter cake on permeability, the core plug was removed from the permeameter, and the filter cake was manually removed. The coreholder and system were re-pressurized to previous conditions, and permeating fluid was re-injected at the same rates to determine post-cleanup permeability performance.

## Test Results

### Fluid Formulations

Three different fluids were formulated with a final density of 10.6 lb/gal using sodium chloride brine as a base fluid. General fluid's formulations are shown in Table 3. All the fluids were hot-rolled at 130°F for 16 hours. pH of the fluid was adjusted as required (9 – 10) using caustic soda/soda ash. Fluids were formulated with a specify clay control packaged requested by customer due to high reactivity of the formation. Wellbore stabilizer is a nanoparticle (NP) The NP is a deformable polymeric molecule with particle size lower than 1 micron. The polymer plays a key role in the packing by filling all void effectively when filter cake is deposited. The NP is placed between other solid particles changing the packing structure, filling all the voids, and conferring flexibility (Pietrangeli 2024 and Addagalla 2024). Lubricant is an ester based component required by the customer and widely used in the region.

The fluids were required to meet the shale inhibition – proven through shale-particle disintegration tests and accretion test, low fluid loss – focused on PPA testing, and return permeability in order to create a fluid capable to drill through the reservoir and generate minimal formation damage.

Table 3—Fluid 1A, Fluid 1B, and Fluid 2: Formulation.

| Product name and function | Units | Fluid 1A | Fluid 1B | Fluid 2 |
|---|---|---|---|---|
| Sodium chloride base brine (9.96 lb/gal) | bbl/bbl | 0.819 | 0.819 | - |
| Sodium chloride base brine (9.60 lb/gal) | bbl/bbl | - | - | 0.801 |
| Wellbore Stabilizer | lb/bbl | 2.0 | 2.0 | 3.0 |
| Optimized bridging agent – Calcium carbonate | lb/bbl | 53.0 | - | 75.0 |
| Coarse bridging agent – Calcium carbonate | lb/bbl | - | 53.0 | - |
| Biopolymer and rheological modifier (Viscosifier & Fluid loss additive) | lb/bbl | 8 – 12 | 8 – 12 | - |
| Xanthan gum | lb/bbl | - | - | 0.7 – 0.9 |
| Starch fluid loss additive | lb/bbl | - | - | 6 – 8 |
| Shale inhibitor package | lb/bbl | 23.0 | | |
| $H_2S$ Scavenger | lb/bbl | 1.0 | | |
| Corrosion inhibitor/Biocide/Oxygen scavenger | lb/bbl | 2.0 | | |
| Lubricant | vol % | 3.0 | | |

A new biopolymer was used to formulate the fluid in order to minimize the need of breakers or additional intervention, was as requested by the customer. A second fluid with traditional products was also formulated to compare the possible damage created by the xanthan gum. Fluid 1A and Fluid 1B were formulated using the new biopolymer as a viscosifier and fluid loss control agent. The difference between Fluid 1A and Fluid 1B is the size of calcium carbonate used as a bridging agent. Fluid 1A had an optimized bridging agent package. Fluid 2 uses xanthan gum as a viscosifier and a regular starch as a fluid loss control agent. Fluid 1A and Fluid 2 used the same optimized bridging agent package.

Drill-in fluids must be tailored to the required challenges of the formation, especially to pore throat size. During drilling operations, the formation is first exposed to the drill-in fluid, no barriers are in place, the drill-in fluid solids start building a low permeability filter cake on the near-wellbore area. The solids start invading the formation while the filter cake is formed. If these solids are too small, they migrate in high concentrations plugging the pore throats. In parallel, the filtrate start to invade the near-wellbore (spurt) altering the wettability of the formation. Low filtrate and minimal solids invasion are the main goal of drill-in fluids to help minimizing formation impediment. Outmans (1963) defines the three stages of filter cake buildup as (1) spurt loss during initiation of the filter cake, (2) buildup of filter cake thickness during which time leak off is proportional to the square root of time, (3) and limitation of filtercake growth by erosion. Best drill-in fluids offer excellent carrying capacities, lubricity, low interaction with reactive shales, and minimal formation damage while the filter cake is built up to guarantee wellbore stability. It is considered a best-in-class fluid when the filter cake is flexible and easily removable.

In order to create a fluid with all the required characteristics by the customer, a new biopolymer was tested for achieving better return permeability values compared to the conventional xanthan gum/starch package.

## Rheological Properties

Rheology profile for all the fluids were determined before and after hot-rolling at 120°F. Plastic viscosity of Fluid 2 formulated with xanthan gum was lower (27 cP) than the fluids formulated with the new biopolymer (41 – 49 cP). The 6 RPM dial reading met the requirements for all the fluids, between 12 and 15, giving a good indication about minimizing possible dynamic sagging while drilling horizontal wells and good hole cleaning (Visinescu and Bouguetta 2013). The 10 second and 10 minute gels for all the fluids were similar to the 3 RPM and 6 RPM dial readings, supporting the claim of minimal dynamic sagging. Low shear rates measurements can be used to simulate complex phenomena such as solids sag or pressure peak due to transient gel breaking on restart (Herzhaft et al 2006).

### Lubricity Test

Coefficient of friction was determined for fluid 1A and Fluid 2 after hot-rolling. The values were very similar (~0.17). No differences in lubricity were observed when using xanthan gum or the new biopolymer as viscosifier.

### Fluid Loss Test

All fluids showed comparable fluid loss results and lower than required when tested on paper while using the API filtration tests (room temperature and 100 psi) and HPHT filtration test (250°F and 500 psi).

PPA fluid loss testing was conducted on the three fluid systems at 150°F and 500 psi differential pressure using a 10 μm aloxite disc to simulate the expected formation pore throat size. Fluids 1A and Fluid 2 incorporated the same optimized bridging package tailored for the target formation, while Fluid 1B utilized a coarser blend of calcium carbonates. Fluids 1A and Fluid 2 exhibited comparable spurt loss values of 0.40 $cm^3$ and 0.20 $cm^3$ respectively, indicating that the bridging package was appropriately matched to the pore throat sizing. Spurt loss is one the most important characteristics of a drill-in fluid. Spurt loss refers to the initial fluid loss of the drilling fluid into the permeable formation before a filter cake is fully formed which can helps to predict formation damage, lower the value implies lower invasion and lower formation impediment. Fluid 1B showed a significantly higher spurt loss of 1.62 $cm^3$and elevated total fluid loss, highlighting the adverse impact of using a coarser bridging blend. These results underscore the importance of selecting a bridging package that aligns with the expected pore throat size and of using an appropriate aloxite disc to accurately represent the formation during laboratory testing. Improper selection of the particle size for plugging the pores of the formation can lead to more fluid invasion causing higher formation damage and potential instability issues (Kumar 2010).

Detailed PPA fluid loss data for all three systems is presented in Table 4, which summarizes spurt loss, 30 minutes, and four hours cumulative fluid loss values. All the fluid loss values obtained after four hours testing were lower than 15 $cm^3$. Fluid 1A demonstrated lower total fluid loss over a four hour period, followed by Fluid 2, and then Fluid 1B.

**Table 4—Fluid 1A, Fluid 1B, and Fluid 2: PPA fluid loss test results.**

| Fluid | Spurt loss, $cm^3$ | Fluid loss after 30 minutes, $cm^3$ | Fluid loss after 4 hours, $cm^3$ |
|---|---|---|---|
| 1A | 0.40 | 1.80 | 9.35 |
| 1B | 1.62 | 6.01 | 12.04 |
| 2 | 0.20 | 5.77 | 11.4 |

### Drill-In fluid and Shale Interaction

Idially return permeability and shale interaction tests are performed using core and/or cutting samples from the field where the fluid will be used. Whole and undamaged Core samples can be difficult to obtain for return permeability tests. Therefore, synthetic cores can be used for the testing helping to understand the basic damaged to the formation by the fluid. However, when the formation is knows to be problematic, the best practice is to test at least the interaction of the shale with the drilling fluid as a whole. Small samples of the formation, cuttings, or "broken" core pieces are easier to obtained. Testing such as shale-particle disintegration and accretion are widely recommended to predict negative interactions with the fluids.

Nahr Umr shale is well known for its reactiveness to water-based drilling fluids. Some authors report that the fractured shale exposed to water-based drilling fluids is the most unstable because it absorbs the combined weakening effects of chemical reactivity and fracture flow and deformation. The poorly consolidated shale is classified as a typical viscoplastic material. It creeps under deviatoric stress, and the boreholes tend to shrink after drilling, which can lead to stuck pipe incidents when open hole duration is long. Others report severe wellbore instability problems in 12.25 in. sections shale, resulting in stuck pipe, partial and total losses, sidetrack, hole pack off, and caving. These problems have caused the significant increase of non-productive time, in some cases, several sidetracks (Su et al 2025).

The following testing shows the interaction of the Nahr Umr shale with the proposed drill-ng fluids. Results showed favorable outcome during shale-particle disintegration and accretion tests; suggesting that both fluids are well-suited for drilling through the Nahr Umr formations. Specifically at reducing the risk of bit-balling and improving hole cleaning efficiency, supporting stable and effective drilling operations in this geological interval.

***Shale-Particle Disintegration Test.*** Fluid 1A and Fluid 2 were formulated with the same inhibition package specifically designed for the very reactive Nahr Umr shale. Dispersion testing conducted on these fluids demonstrated strong shale recovery performance, Fluid 1A retained over 98% of the shale integrity while Fluid 2 retaining over 94% of the tested shale material. This high level of recovery indicates effective inhibition and minimal shale dispersion, suggesting that both fluids are well-suited for maintaining wellbore stability and ensuring efficient hole cleaning while drilling through the Nahr Umr formation. London clay was also tested to establish a reference over Nahr Umr shale when using Fluid 1A. The shale recovery was 98.3%. Fig. 1 shows the shale before and after testing. Shale inhibition package chosen is compatible with the different viscosifiers and provides the required inhibition for the reactive formation.


**Figure 1—Fluid 1A and Fluid 2: Shale-particle disintegration test results using Nahr Umr shale and London clay.**

***Accretion Test.*** In alignment with the shale-particle disintegration test, both fluids demonstrated strong performance in accretion testing with Nahr Umr shale and London clay. Accretion levels for both fluids were measured at less than 2%, indicating effective inhibition and minimal interaction with the shale surface. Fluid 1A shower an accretion lower than 1% when using Nahr Umr shale and 0.75% when using London clay. Fluid 2 showed an accretion of 1.3% when using Nahr Umr shale for the testing. Fig. 2 shows the metal rod appearance after the accretion test using different fluids and shales.

| Fluid 1A and Nahr Umr Shale | Fluid 1A and London Clay | Fluid 2 and Nahr Umr Shale |
|---|---|---|
|  |  |  |

Figure 2—Fluid 1A and Fluid 2: Metal rod after shale accretion test.

## Return Permeability Test

Return permeability testing was conducted on Fluid 1A, Fluid 1B, and Fluid 2 to assess formation compatibility and fluid-induced damage, with flow rate being the only variable across tests.

Fluid 1A, formulated with an optimized bridging package and the new biopolymer, delivered the most favorable results, achieving 89.7% regain permeability after mud-off without requiring filter cake removal. This performance was accompanied by minimal filtrate invasion (2.17 $cm^3$, 29%), indicating excellent sealing efficiency and low formation damage. Fig. 3 shows the results of the return permeability tests for Fluid 1A using testing methodology 2. The liftoff pressure was 9.31 psi. Filter cake was thin (< 2 mm) and flexible. No further testing was conducted for the sample due to the high initial return permeability value. Some damage can be attributed to filtrate invasion.

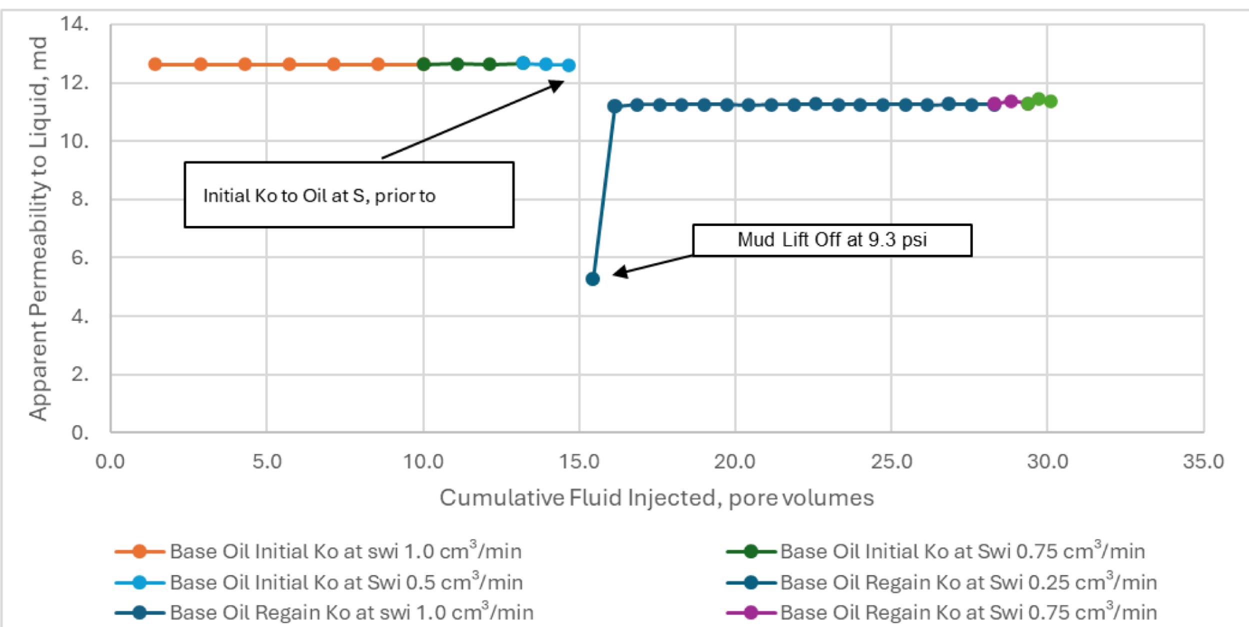


Figure 3—Fluid 1A: Return permeability test results using testing methodology 2.

Fluid 1B, which incorporated a coarser bridging blend, exhibited higher filtrate invasion (4.00 $cm^3$, 59%) and a lower initial regain permeability of 71.1% as it can be seen in Fig. 4. Due to the extensive damaged the core underwent further evaluation to determine the cause of the damage. The return permeability improved to 78.9% following mechanical filter cake removal, demonstrating that part of the damaged was caused by solids invasion. Trimming of the core was conducted and return permeability did not increase suggesting more than one damage mechanisms. After trimming and centrifugation, the return permeability improved further to 91.6% suggesting that the damaged was exacerbated by the high filtrated invasion, altering the wettability of the core and increasing its capillary pressure. The liftoff pressure was 15 psi. Thickness of the filter cake was close to 4 mm. Filter cake was flexible and easily removed from core face.

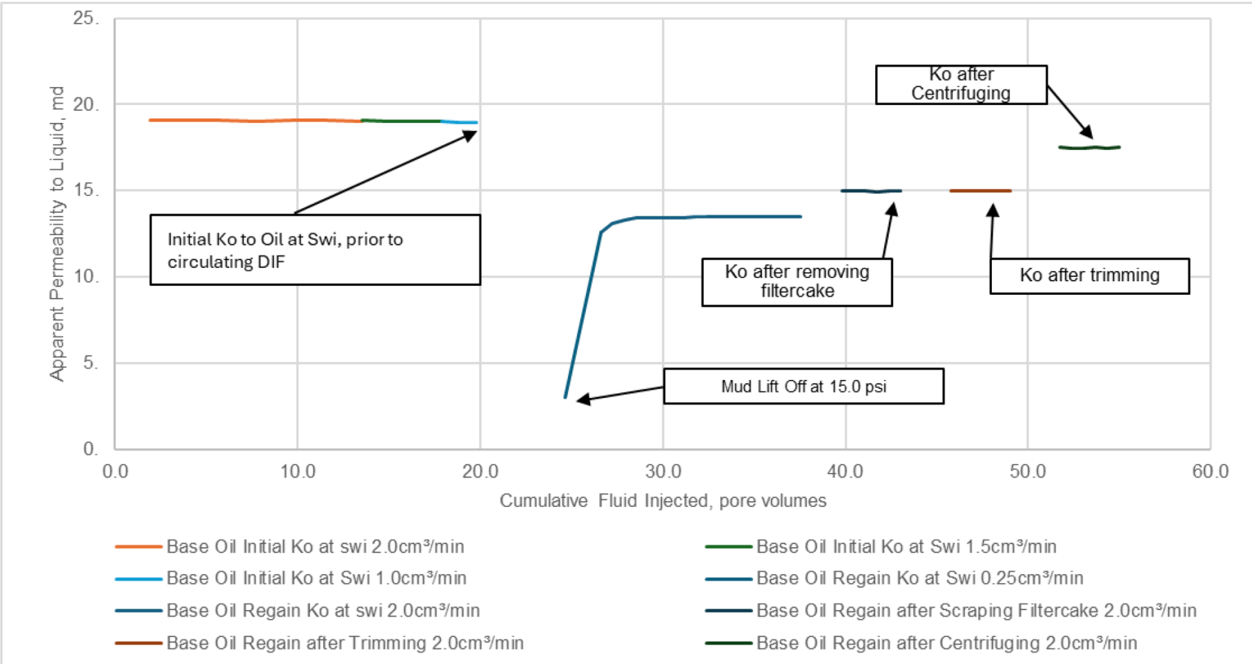


**Figure 4—Fluid 1B: Return permeability test results using testing methodology 2.**

Fluid 2 was tested using testing methodology 1 and 2. The main difference between the methodologies is the high permeating oil flow rates used for testing, methodology 1 up to 6 $cm^3$/min compared to methodology 2 up to 2 $cm^3$/min.

The fluid test results showed the highest filtrate invasion (up to 4.24 $cm^3$, 79%) when using testing methodology 2 and the lowest regain permeability (55.7%) after mud-off. Higher returns were observed using the new biopolymer with and without the optimized bridging package and same testing methodology. Due to the extensive damage to the core, the core plug underwent further evaluation. The return permeability improved to approximately 7% after mechanical filter cake removal. No trimming was performed to the core. After centrifugation the return permeability increased to 84%. Therefore, the damage was a combination of polymer and filtrate invasion. Fig. 5 shows the return permeability test results for Fluid 2 when using testing methodology 1.

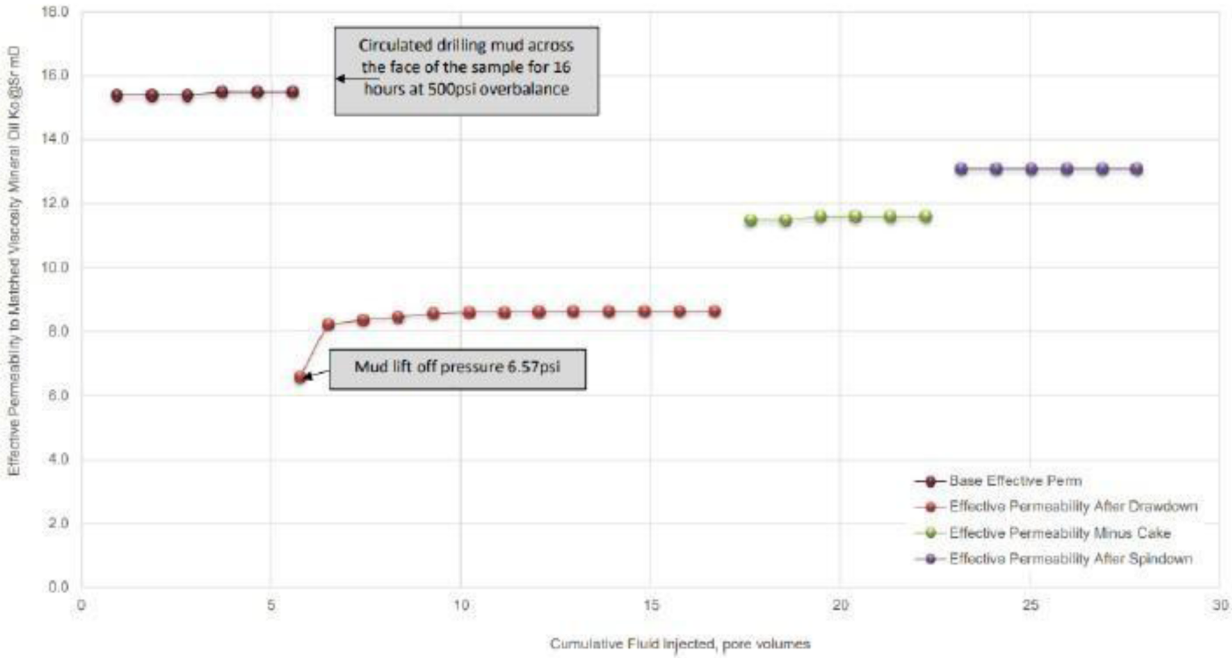


**Figure 5—Fluid 2: Return permeability test results using testing methodology 1.**

Results using test methodology 1 are very similar to the values obtained using test methodology 2. The regain permeability after mud-off was close to 5%. It increased to 7% after mechanical removal of the filter cake and increased further to 8% after centrifugation. The damage created by the xanthan gum cannot be removed by increasing the flow rate of the permeating oil as seen in Table 5 comparing the two methodologies for Fluid 2.

**Table 5—Return Permeability results.**

| Fluid | Testing methodology | Filtrate invasion | Flow rate ($cm^3$/min) | % Regain after mud-off | % Regain after mechanical filter cake removal |
|---|---|---|---|---|---|
| Fluid 1A | 2 | 2.17 (29%) | 1 | 89.7 | - |
| Fluid 1B | 2 | 4.00 (59%) | 2 | 71.1 | 78.9 |
| Fluid 2 | 2 | 4.24 (79%) | 1 | 55.7 | 74.8 |
| | 1 | 3.65 (68%) | 2 | 57.6 | 75.5 |
| | | | 4 | 59.0 | 76.0 |
| | | | 6 | 59.4 | 76.0 |
| | | | 2 | 58.1 | 75.5 |

Liftoff pressure for the fluid was 6.47 psi when using methodology 1 and the liftoff pressure was 6.57 psi when using testing methodology 2. Filter cake thickness was close to 2 mm in both cases. It was also flexible and easy to remove.

Elmgerbi in 2021 concluded that lift-off pressure has an inverse relation to the permeability of the filter media. In this case, the low permeability of the outcrops will generate high lift off pressures. They also concluded that cleaning efficiency is reduced by filtration time, especially for low permeability media. Therefore, if a filter cake with optimal packing is deposited on top of the core, the lift off pressure decreases, and the cleaning efficiency of the well is easily achievable. Additionally, he use of the NP into the fluids formulations as a wellbore straightening agent confers flexibility to the filter cake and contributes to the lower liftoff pressure as seen by Pietrangeli et all 2024.

All the results, summarized in Table 7, highlight the improved performance of using the new biopolymer over xanthan gum, particularly Fluid 1A, in minimizing formation damage and enhancing permeability recovery, emphasizing the importance of optimized bridging design, and fluid composition in a drill-in fluid system.

Fig 6 shows the wellbore face of the Indiana core before and after mud-off when exposed to Fluid 1A or Fluid 2. Reservoir characteristics and properties including porosity, absolute and relative permeability, pore pressure, pore size distribution, shale chemistry, capillary pressure, and residual fluid saturations, play important roles in controlling both the dynamic formation of filter cake and the time evolution of the invasion process. Particle size distribution, cake compressibility, cake lubricity, state of flocculation, and cake thickness are cited as the most important properties of the filter cake. The drill-in fluid leak off rate into the reservoir is one of the critical parameters that need to be controlled carefully during drilling and completion operations. With increasing open hole completion operations, the problem gets exacerbated because the fluid remains in the well for a longer time. Excessive fluid invasion can give rise to a number of problems: (1) differential sticking of the drill string, (2) invasion of whole DIF or filtrate into pay zones increasing the probability of the formation damage by connate filtrate or emulsion damage, (3) filtrate cake invasion changing the properties of the formation surrounding the borehole (Outmans, 1963), and (4) propagation of micro-fractures by invasion of fine rigid solids.

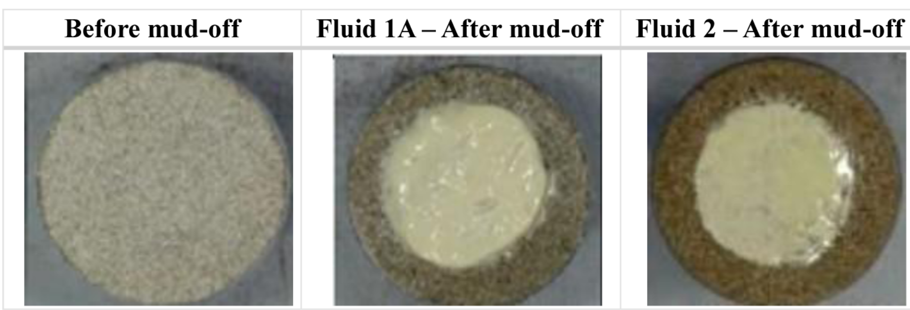


**Figure 6—Fluid 1A and Fluid 2: Wellbore core face before and after mud-off.**

## Conclusions

- Fluid 1A demonstrated improved performance across all key evaluation criteria, confirming its suitability for drilling through the Nahr Umr formation.
- Fluid 1A, formulated with an optimized bridging package and optimized base fluid, achieved a low spurt loss and total fluid loss, along with the highest regain permeability (89.7%) without requiring filter cake removal. These results indicate excellent formation compatibility and minimal damage.
- Fluid 1B, although designed with a coarser bridging blend, still delivered solid performance, achieving 79% regain permeability after filter cake removal, which underscores the robustness of using the new biopolymer as a viscosifier and fluid loss control agent in the base formulation.
- Fluid 2 met all the requirements but the return permeability showing deep damage to the core by polymer and filtrate invasion.
- Both variants of Fluid 1 (A and B) also exhibited strong shale inhibition, with dispersion recoveries exceeding 94% and accretion values below 1.3%, minimizing the risk of bit-balling and ensuring effective hole cleaning.

- Lubricity testing further confirmed no differences using the new biopolymer or xanthan gum as a viscosifier and its capability in high-temperature environments, with low lubricity coefficients supporting reduced torque and drag.
- Overall, the data clearly supports that the fluid formulated with the new biopolymer, especially optimized Fluid 1A, as the preferred fluid system for maximizing drilling efficiency, maintaining wellbore stability, and minimizing formation damage in highly reactive shales like Nahr Umr and London Clay.

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## Nomenclature

API = American petroleum institute
CoF = Coefficient of friction
DIF = Drill-in fluid
EOR = Enhanced oil recovery
HAPAM = Hydrophobically associating polymers
HPHT = High pressure high temperature
NP = Nanoparticle
PPA = Permeability plugging apparatus
PSD = Particle size distribution
PV = Plastic viscosity
RPM = Revolutions per minute
WBF = Water-based fluid
XG = Xanthan gum
YP = Yield point

## SI Metric Conversion Factors

| | | | | | |
|---|---|---|---|---|---|
| (°F – 32)/1.8 | | | | = | °C |
| $cm^3$/min | × | 6 | E+07 | = | $m^3$/s |
| cP | × | 1 | E-03 | = | Pa·s |
| ft | × | 0.3048 | | = | m |
| hours | × | 360 | | = | s |
| in. | × | 2.54 | E-02 | = | m |
| lbm/100$ft^2$ | × | 4.788026 | E-01 | = | Pa |
| lbm/bbl | × | 0.35 | | = | kg/$m^3$ |
| lbm/gal | × | 1.198264 | E+02 | = | kg/$m^3$ |
| minutes | × | 1.7 E-02 | | = | s |
| psi | × | 6.894757 | E-03 | = | MPa |

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