

# High-Performance Polymer Systems for Drilling and Completing Challenging Formations

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## Abstract

Oil-based mud (OBM) has been used extensively to drill problematic and producing formations due to its robust performance and thermal stability. The growing environmental concerns and the high cost of synthetic OBM drove the industry towards a search for high-performance water-based mud (HPWBM). However, using conventional WBM to drill problematic formations, such as shale formations, is still challenging. Long laterals are required to maximize production and reduce drilling costs. Borehole instability, higher torque and drag, and a lower rate of penetration are encountered when drilling with WBMs, affecting drilling time and cost. This study evaluates new high-performance polymers (HPPs) developed to drill challenging formations, where salinity and temperature limit the use of natural polymers and conventional partially hydrolyzed polyacrylamide (PHPA) products.

The mud systems were formulated in the laboratory with various densities (8.5-16 ppg) to account for flexibility of drilling envelopes. The systems comprise of saturated brines with unique polymeric additives (HPPs) to improve the fluid performance, particularly suspension, stability, rheological, and filtration properties. The developed systems were evaluated by measuring rheological and suspension properties, thermal stability, fluid loss, shear degradation, and clay inhibition. The new polymers were challenged by increasing the testing temperature up to 350°F, and thermal stability was evaluated for extended drilling time.

The HPPs showed excellent thermal stability at up to 350°F for 5 days, low fluid losses (7-14 mL), good suspension properties (LSYP = 8-12 & VSST < 1.0), and high shear resistance and salt tolerance. Low shale dispersion rates were observed with reactive clay samples for extended drilling time (16 hrs). More than 95% of clay cuttings were recovered with the introduced mud systems, while less than 1% was recovered with fresh water.

## Introduction

Historically, OBM systems, composed of diesel or mineral oil alongside weighing agents, clay viscosifiers, and emulsifiers, have served to alleviate drilling complications such as wellbore instability and productive formations damage (Friedheim and Conn, 1996). Additionally, OBM furnishes

lubricity and temperature stability. Nonetheless, the application of OBM is constrained by its excessive cost and environmental implications related to treatment, handling, and disposal. These limitations have diminished OBM's appeal as the preferred system for operators.

In recent times, a notable shift has occurred toward the Water-Based Mud (WBM) systems, propelled by operators' growing demand for cost-effective and environmentally benign drilling solutions for more challenging geological formations. Unlike OBM, WBM diminishes the necessity for expensive cuttings treatment and waste disposal, while presenting a more economical mud system. Significant advancements in WBM systems and additives have been made to mitigate issues with wellbore stability (Patel et al., 2007). These advanced HPWBM systems have alleviated common drilling issues such as wellbore instability, cuttings settling, and fluid loss. They can utilize various locally available waters, enhance the rate of penetration (ROP), and reduce drilling time, costs, and emissions. For instance, Mahrous et al. (2023) reported the utilization of an HPWBM system for drilling the top hole and lower sections, resulting in significant cost savings through reduced drilling time, more than 11 days ahead of schedule, and 20% under budget. However, HPWBM systems are still limited by temperature stability.

The HPWBM systems discussed in this paper formulated with a blend of water, HPPs, and other additives, affording them properties akin to OBM. One significant advantage of these systems is their enhanced thermal stability and filtration performance. In deep and extended-reach wells, where temperatures and pressures can be extreme, conventional WBM may deteriorate and lose performance. These systems, on the other hand, withstand harsh conditions and maintain consistent performance throughout the drilling process. This paper will detail the materials and methods employed in the experiments, followed by a comprehensive description of rheology and thermal stability tests. A discussion on sag tendency will demonstrate the system's exceptional performance in cutting carrying and suspension. The fluid loss tests revealed the additives' excellent filtration performance at elevated temperatures. The developed system emerges as an environmentally friendly and cost-effective drilling fluid system, offering exceptional performance and representing an

ideal option for various drilling and completion applications in challenging formations. The paper also highlights the potential applications for the developed polymers and addresses the gaps and next steps to increase the readiness of such technologies.

## Materials and Methods

Several mud systems were designed and evaluated in the laboratory under different testing conditions. These systems comprised of saturated brines as base fluid, and high-performance polymers (SNF HPP-1 and SNF HPP-2) to serve as viscosifiers with additional fluid-loss-control function. The saturated brines were formulated in the laboratory in various densities (8.5 to 16 ppg) to account for flexibility in drilling operations. Sodium chloride, sodium bromide, calcium bromide, zinc bromide, or a mixture of these salts was used to prepare the brine for the various mud systems.

SNF HPP-1 system is initially designed for drilling intermediate casing, where sodium chloride brine (10-20%) is used, and barite, calcium carbonate, or any other weighting agents can be used to adjust the mud weight. The targeted temperature for this system can reach up to 250°F. On the other hand, SNF HPP-2 is intended for solid-free mud systems prepared using sodium bromide, calcium bromide, zinc bromide, or a combination of these salts, depending on the targeted density. The primary use of this mud system is to drill producing formations (Drill-in mud), with very low mud losses, where downhole temperatures could reach up to 350°F. This system can also be designed to complete oil and gas wells or as a high-viscosity pill.

A blend of sized calcium carbonate, depending on the formation pore size, is used as a bridging agent to improve, along with HPP, the filtration properties and minimize the fluid invasion into the drilled formations. Oxygen scavenger is also added to both systems to remove dissolved oxygen, reduce corrosion, and further protect the polymeric additives from accelerated hydrolysis, especially at elevated temperatures (Thomas, 2019). The developed mud systems were then tested in the lab by evaluating rheological, suspension, and filtration properties. We evaluated the long-term performance by testing thermal stability, fluid loss, and shear degradation over an extended drilling time. We also studied the clay-fluid interaction by conducting a series of clay dispersion tests. Figure 1 summarizes the experimental workflow of this study.

### Rheology and Thermal Stability

Rheological performance affects the drilling efficiency and drilling time significantly. Optimized rheological properties help control many drilling parameters such as torque and drag, hole cleaning and solid suspension, mud losses, rate of penetration, and wellbore hydraulics (Mohamed et al., 2021). For instance, the high rheological properties increase the frictional pressure drops and equivalent circulating density in the annulus, which may induce some fractures into the drilled formation and increase the risk of lost circulation events (Magzoub et al., 2021; Sun and Huang, 2015). Low rheological properties, at the same time, result in poor hole cleaning where

solid particles accumulate in the wellbore, leading to unoptimized wellbore hydraulics and lower rates of penetration. In severe cases, poor suspension properties may also lead to the settlement of weighting agents, causing significant density variations and well control incidents (Bern et al., 2000; Mohamed et al., 2020; Omland et al., 2007). Thus, optimizing rheological properties is vital in cost-effective, efficient, safe drilling operations.

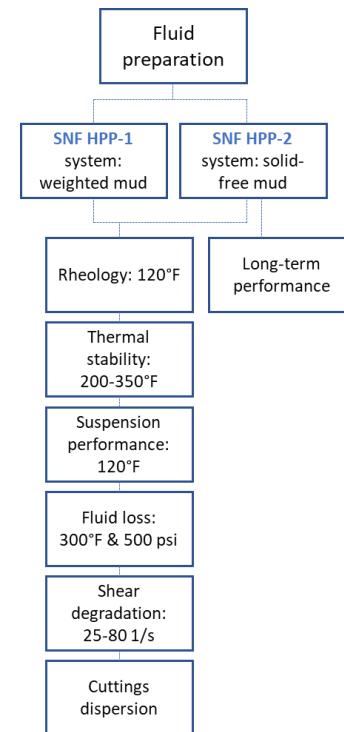


Figure 1 – Workflow of the experimental evaluation of the developed HPPs.

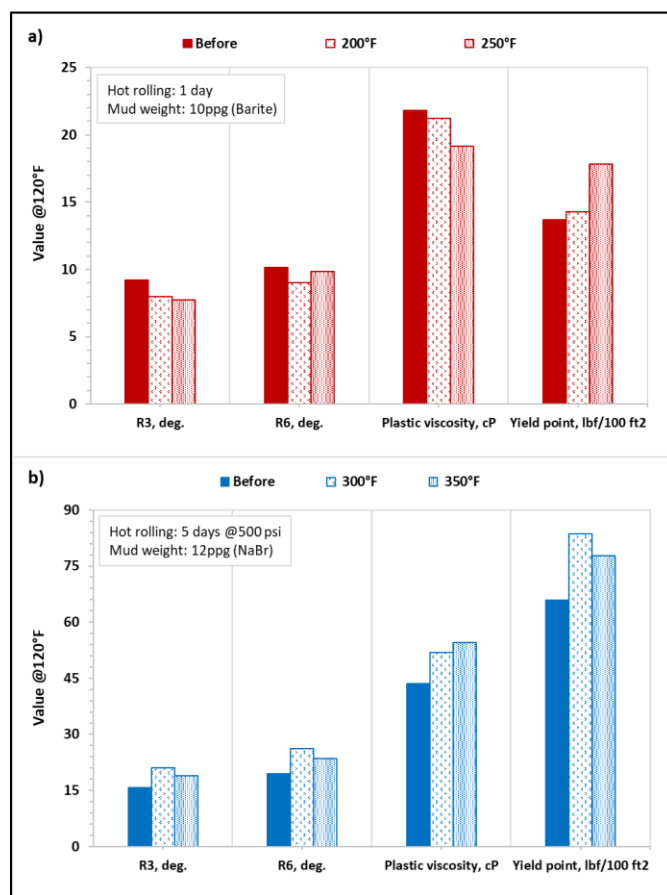
Mud viscosity and cuttings suspension are achieved by adding clay and polymeric additives to the drilling fluid system, such as bentonite, natural polymers, and synthetic polymers. These products are referred to in the industry as viscosifiers, and their performance is highly impacted by downhole conditions. Selecting the best viscosifier is bounded by salinity, downhole temperature, intended application, and drilling cost. Clay suspensions are inexpensive and suitable to drill conductors and surface casings sections. Introducing polymeric additives to the clay systems is essential when drilling deeper to improve the filtration properties (Finger and Blankenship, 2010). It is recommended to avoid clay systems when drilling producing formations as fine clay particles are damaging to the formation and difficult to remove. Natural polymers are also extensively used in drilling such as xanthan gum and cellulosic products. These products are very resilient to high salinity; however, they are restricted by downhole temperature (Mohamed et al., 2023). The oil and gas industry has also seen great advancement in synthetic polymers for various

applications. Synthetic polymers are flexible and can be manufactured using different processes and monomers to target specific downhole conditions. However, conventional synthetic polymers are prone to chemical and physical degradation imposed by elevated temperatures, high salinity, divalent ions, and continuous shearing (Ma et al., 2019). Incorporating special monomers such as sulfonated monomers has helped increase the salt, temperature, and shear resistance of synthetic polymers (Thomas, 2019), making them good options for drilling and completion operations.

The drilling fluid systems, formulated with SNF HPP-1 and SNF HPP-2 polymers, were evaluated in the lab by measuring the rheological properties before and after hot rolling at different temperatures (200-350°F). All measurements were conducted at 120°F and atmospheric pressure. As shown in Figure 2, both polymer systems exhibited good rheological and suspension properties. SNF HPP-1 system showed a yield point between 13-18 lbf/100 ft<sup>2</sup>, while the low-end rheology (R3 & R6) ranged between 8-10 deg. at 120°F. The R3 and R6 of SNF HPP-2 system varied between 15-26, while the yield point and plastic viscosity was ranging between 65-80 lbf/100 ft<sup>2</sup> and 40-55 cP, respectively. As per field practice, maintaining sufficient low-end rheology ensures good hole cleaning and solid suspension in the annular space where low shear rates are encountered, especially in highly inclined and horizontal sections (Thomas et al., 2013). Since maintaining the rheological properties downhole is as crucial as optimizing them, fluid stability under downhole conditions should also be evaluated before field implementations. The mud systems were hot rolled at various temperatures, 200-350°F, to account for broad downhole conditions. SNF HPP-1 polymer was thermally stable at up to 250°F, and no notable change in rheological properties was seen after hot rolling for 24 hrs. On the other hand, SNF HPP-2 polymer was primarily manufactured using different chemistry to target high-temperature applications. Therefore, SNF HPP-2 polymer was found more resistant to temperature and showed excellent thermal stability at up to 350°F for an extended period (up to 5 days). A slight increase in the rheological properties was observed after hot rolling due to the complete polymer hydration in the saturated brine over time.

### Sag Tendency (VSST)

Carrying and transporting drilled cuttings to the surface is one of the main drilling fluid functions (Fink, 2015). Inefficient wellbore cleaning or poor suspension of solid particles and drilled cuttings when mud circulation is stopped cause many complications to the drilling process. These challenges can vary from lowering the ROP and drilling efficiency, pipe sticking, unoptimized wellbore hydraulics, increased equivalent circulating density (ECD), mud losses, and in severe cases well-control incidents might occur (Boyoun et al., 2019). Hole cleaning and solid suspension are dependent on cutting



**Figure 2 – Rheological properties and thermal stability of a) SNF HPP-1, and b) SNF HPP-2 systems at various temperatures.**

properties, mud properties, wellbore geometry, and other operational parameters such as circulation rate and pipe rotation (Werner, 2018). In this paper, our focus is on mud properties and how the developed polymer systems can improve mud capability in hole cleaning and solid suspension, especially with low circulation velocities.

As shown in the previous section, the new HPPs exhibited excellent low-end rheology (>8) and yield point (>12), which can be great indicators of suspension capability. Additionally, sag tendency was studied with a high-density weighting agent to evaluate the mud suspension properties. Barite is one of the common weighting agents used with drilling fluids due to its high density ( $\geq 4.1$  g/cc), low cost, and availability. However, solid sag is likely with barite, where solid particles tend to settle at the bottom, causing density variations and well-control issues (Bern et al., 2010). Therefore, barite was added to both polymer systems to formulate various mud densities, 10-19 ppg. Sag tendency was measured using the viscometer sag shoe test (VSST) which is well known in the industry to evaluate sag tendency in dynamic conditions. The standard procedure of the test is well documented in the literature (Zamora and Bell, 2004).

Figure 3 shows the sag tendency with the two developed

polymers at the standard test conditions (100 RPM at 120°F for 30 min). The VSST with SNF HPP-1 ranged between 0.57-1.25 lbm/gal, while SNF HPP-2 yielded a VSST factor of 0.5-0.6 lbm/gal. The sag tendency with both systems was within the acceptable range and sag is less likely. According to Bern et al. (2010), when VSST is 1.6 lbm/gal or above, sag problem is anticipated. The bed pickup percentage (BPU) is another parameter that can be obtained from the dynamic sag test, which reflects the percentage of the formed solid bed that can be removed by mud circulation. BPU is measured after rotating the viscometer at 600 RPM for 20 minutes right after the VSST measurement is completed. The higher the BPU %, the easier it is to remove the accumulated solids and clean the well. As shown in Figure 3, between 73-92% of the formed bed can be removed with both mud systems in only 20 minutes of rotation.

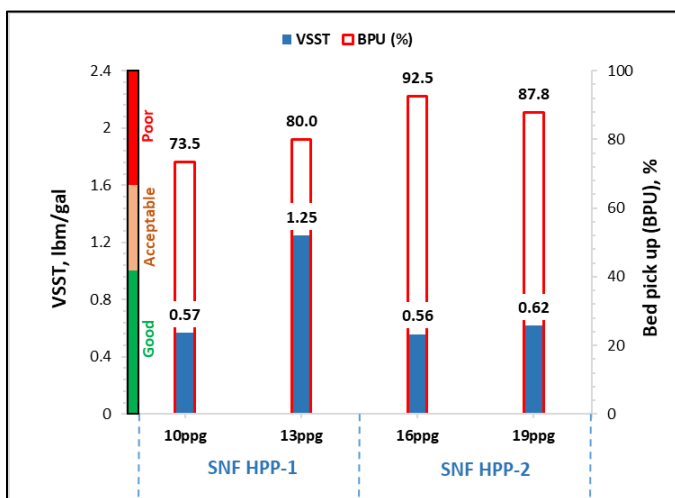


Figure 3 – Sag tendency of SNF HPP systems at 120°F.

### Fluid Loss and Filter Cake Removal

Mud losses are one of the inevitable issues faced during drilling operations, particularly in overbalanced drilling. Depending on the loss severity, mud losses can be a root cause for several drilling problems such as wellbore instability, differential sticking, poor wellbore cleaning, casing and cementing placement, formation damage, and well control incidents (Magzoub, 2021). Therefore, fluid loss phenomenon has been given great attention in the industry. Many theoretical, laboratory, and field studies were performed to fully understand the mechanisms and affecting factors of fluid loss, and many more fluid loss control additives were introduced. Fluid loss control additives are incorporated in the drilling mud and cement formulations to minimize mud loss and mitigate its consequences. Fluid loss is one of the main differences between WBMs and OBMs, where the latter yields extremely low fluid filtrate compared to the first. Thus, special fluid loss control products should be added to the mud formulation when introducing and designing HPWBM as a replacement for OBMs.

In this study, the fluid loss with both HPP mud systems was measured at high-temperature conditions using a HTHP filter press. We conducted the tests at 500 psi differential pressure (800/300 psi), and a temperature of 250°F for SNF HPP-1 and 300°F for SNF HPP-2. SNF HPP-1 polymer was mixed with 10% NaCl brine and barite as a weighting agent. Since SNF HPP-2 is introduced as a high-performance polymer to work with HPWBM and drill-in fluids, the fluid loss control performance was evaluated with three different brine systems, sodium bromide, calcium bromide, and a combination of sodium and zinc bromide, to account for a broad mud weight range (12-16 ppg). Without any fluid loss control agent, SNF HPP-1 polymer exhibited good filtration control at 250°F, with an API fluid loss of 23 mL/30 min, compared to ~30 mL/30 min for regular viscosifiers used in the industry such as xanthan. Therefore, SNF HPP-1 also provides fluid loss control in addition to the viscosity control.

On the other hand, Figure 4 compares the filtration performance of SNF HPP-2 polymer with the three different drill-in systems (12, 13, and 16ppg). SNF HPP-2 showed excellent fluid loss control without adding any fluid loss control agent to the drill-in systems. The API fluid loss ranged between 7 and 14 mL/30 min for the three fluid systems and the lower range was recorded with the higher-density fluid (16 ppg). These low filtrate volumes are attributed to the robust filter cake that the polymer molecules form on the filtration medium. This filter cake forms a vigorous seal on the face of the drilled formation and minimizes the drill-in invasion into the wellbore. However, in ideal situations, this formed filter cake should be thin, impermeable, and easy to remove after drilling operations.

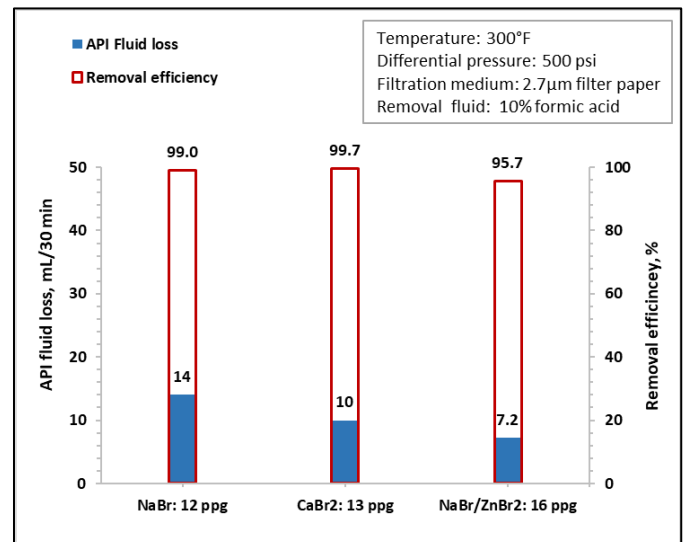


Figure 4 – Fluid loss and filter cake removal efficiency of SNF HPP-2 systems.

Filter cake removal is required for proper casing and cement placement, and before the production phase to remove all

hydrocarbon flow restrictions around the wellbore and maximize well productivity (Mohamed et al., 2020). Removal jobs can be challenging if the polymer and solid particles are not soluble in acids. For this reason, the filter cake removal efficiency of the developed polymer was tested in the lab using a mild acid (10% formic acid). The removal tests were performed at the same fluid loss conditions (300°F), using the HTHP filter press setup. Removal fluid consists of 10% formic acid, 1-2% corrosion inhibitor, and 88-89% water. The formed filter cake was statically soaked in the acid solution for 6 hrs, and the removal efficiency was quantified by measuring the filter cake weight before and after removal tests. As shown in Figure 4, above 95% of the formed filter cake could be dissolved with 10% formic acid in one stage, which reflects the ease of cleaning the deposited polymers on the face of the drilled formation. The exceptional fluid loss control performance of SNF HPP-2 polymer and the high removal efficiency with mild acids make this polymer a great candidate to serve as both a viscosifier and fluid loss control agent with HPWBMs and drill-in fluids.

### Long-Term Performance

The increasing energy demand has pushed the industry towards continuous development in exploration, drilling, production, and stimulation technologies. Taping into unconventional shale plays has made a great shift in drilling operations, where drilling horizontal wells with laterals of thousands of feet has become possible and more feasible. For instance, in 2004, the drilling program in the Marcellus shale started with vertical wells, and in the period between 2006 and 2016, over 800 horizontal wells were drilled with an average lateral length of ~4,000 ft. Two years later, the average lateral length reached to almost 9,500 ft with a maximum lateral length of 18,000 ft (Doak et al., 2018). This great advancement required an integrated drilling program to improve the drilling efficiency, considering drilling rigs, directional tools, drilling fluids, and drilling practices. Fluid selection and performance play a significant role in drilling time and cost, especially in long horizontal laterals where efficient hole cleaning, good lubricity, and shale inhibition are required. As we mentioned earlier, maintaining good fluid performance throughout the drilling operation is vital. Therefore, the long-term performance of the newly developed HPPs was investigated to ensure that the polymer can withstand the harsh drilling conditions for an extended time that can reach several days while drilling the lateral sections.

SNF HPP-2 polymer was added to different brine systems with various densities, 8.5-16 ppg, to account for the flexibility of the drilling envelope. All these systems were exposed to elevated temperature (300°F) for up to 5 days. Rheological properties were measured before and after hot rolling to evaluate the thermal stability for a prolonged drilling time. As shown in Figure 5, SNF HPP-2 yielded good rheological and suspension properties with the low and high salinity brine

systems. Low-end rheology (R3 & R6) ranged between 8 and 15 deg., and the yield point varied between 35-65 lbf/100 ft<sup>2</sup>. Despite the elevated temperature, high salt concentration, and prolonged exposure, all the drill-in fluid systems were very stable and no significant deterioration in the rheological performance was recorded. However, a slight increase in the rheological properties was observed after hot rolling due to the complete polymer hydration over time.

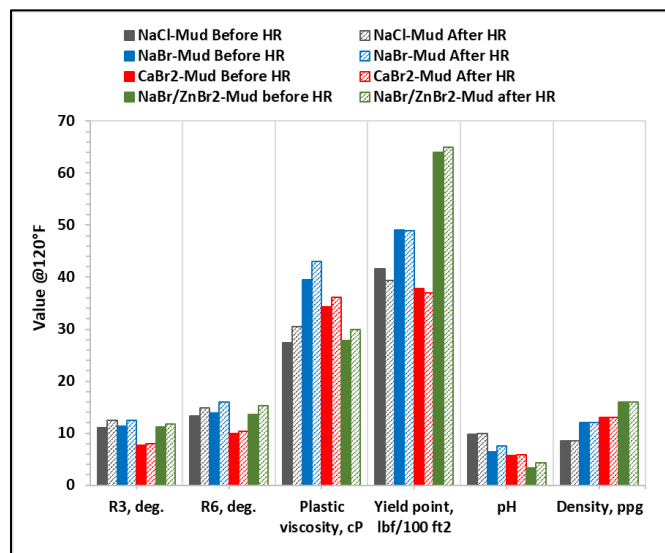


Figure 5 – Rheological properties and thermal stability of SNF HPP-2 mud systems after 5 days of hot rolling at 300°F.

Moreover, the filtration control capability was also evaluated for an extended drilling time to ensure a stable performance over time. The fluid loss experiments were run at 250-300°F temperature and 500 psi differential pressure for up to 24 hrs, and SNF HPPs were compared with a regular viscosifiers used with conventional WBMs. The conventional mud yielded an API fluid loss of 35 and 48 mL/30 min at 250°F and 300°F, respectively. As shown in Figure 6, conventional mud started with low filtrate volumes at 300°F then increased progressively over time to reach 150 mL in one hour, and the experiment was then stopped. Despite the good control for the standard fluid loss experiment duration (30 min), conventional mud failed to maintain the filtration control for an extended time due to the thermal degradation of the polymer at 300°F. Even at 250°F, removing the fluid loss from the conventional mud resulted in a progressive filtration that reached 98 mL in around 6 hrs at 250°F. We reported this data just to highlight how essential are the fluid loss agents with conventional viscosifiers, especially for extended drilling time. In contrast, without adding any fluid loss control additive, SNF HPPs maintained low fluid loss for up to 24 hrs. After 24 hrs, SNF HPP-1 yielded a total fluid loss of 82 mL at 250°F, while 61.5 mL filtrate volume resulted with SNF HPP-2 at 300°F.

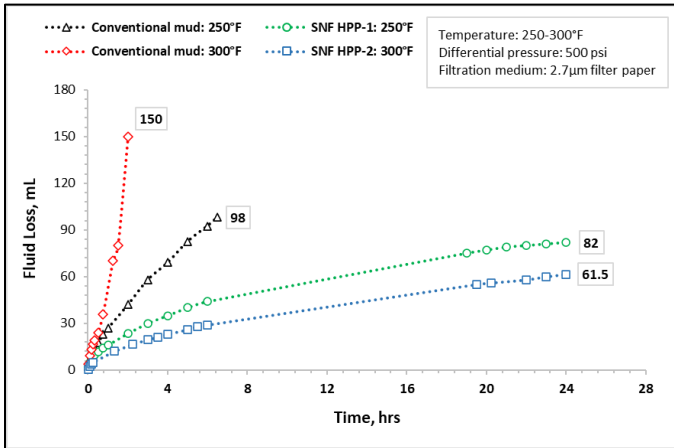


Figure 6 – Long-term HTHP fluid loss of SNF HPPs.

Shear degradation is another factor to consider when evaluating the physical stability of polymeric additives. Continuous shearing is another physical threat to polymeric additives since the fluid is circulated through mud pumps, mud lines, drill pipes, bit nozzles, and back to the solid removal equipment (Thomas, 2019). The highest shearing takes place through mud pumps and drill bit nozzles. Thus, a shear degradation study was also conducted to evaluate the shear resistance of the new polymer systems. A shear bomb setup (Figure 7) was used in this study, where the polymer solution is exposed to extreme shear rates through a 1/8”-tube (4” long).

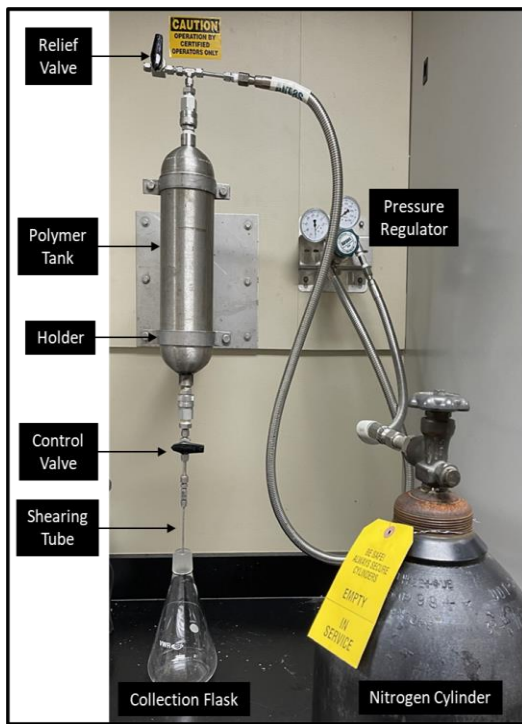


Figure 7 – Shear bomb setup.

Figure 8 compares the rheological properties of SNF HPP systems after each cycle of shearing. The polymer solutions (with 10% NaCl) were continuously sheared at 28,000 s<sup>-1</sup> for five cycles to simulate the mud circulation through the bit nozzles, and one last cycle was done at 100,000 s<sup>-1</sup>. Both polymers (SNF HPP-1 & 2) were very resistant to shearing and no reduction in the rheological properties was recorded after shearing. Unlike conventional PHPAs, SNF HPP unique chemistry provided high tolerance to shearing, salinity, and temperature, making them more resilient under a broad range of drilling conditions.

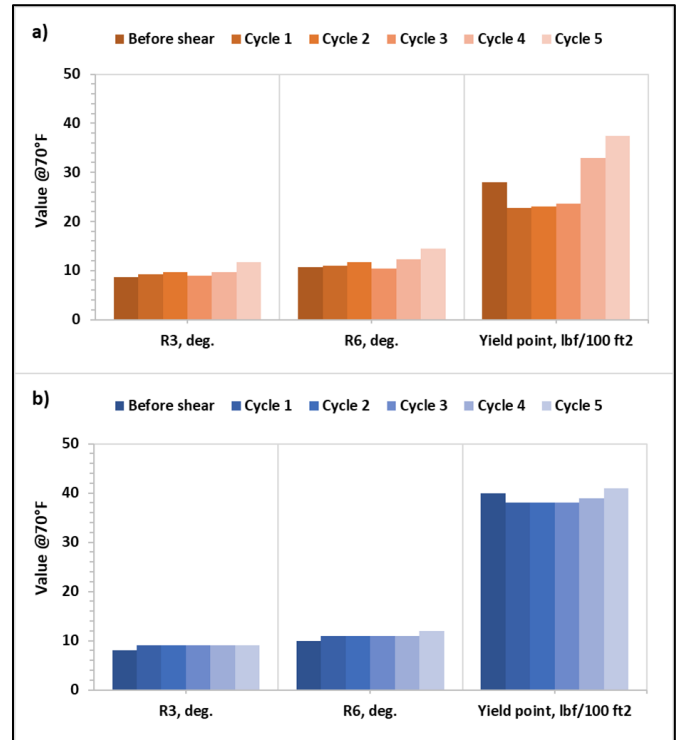
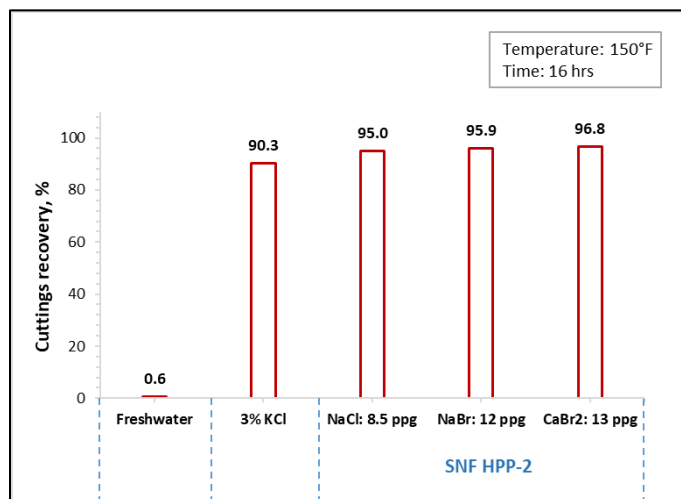


Figure 8 – Shearing effect on a) SNF HPP-1 polymer, and b) SNF HPP-2 polymer, in 10% NaCl.

**Cuttings Dispersion**

Hot rolling dispersion test is a simple useful tool to study the fluid-shale/clay interaction from the cuttings’ integrity aspect rather than from the formation side. It qualitatively evaluates the drilling fluid system capability to stabilize shale and clay cuttings to avoid any complications that might occur from cuttings dispersion into the drilling mud, such as the increased viscosities and ECD. The dispersion tests were performed using sodium bentonite cuttings to represent reactive clays. The sized bentonite cuttings were added to the different fluid samples and hot rolled at 150°F for 16 hrs. The fluid was then cooled and poured over a sized mesh to recover the cuttings. Afterward, the cuttings were washed, dried, and weighed, and the recovery percentage for each fluid was then calculated. SNF HPPs performance was compared to

freshwater and 3% KCl brine, as shown in Figure 9. Clay cuttings were completely dispersed in freshwater and less than 1% of the cuttings were recovered. In contrast, the presence of salts with 3% KCl solution and SNF HPP systems effectively inhibited the clay cuttings and over 90% recovery was recorded. SNF HPP showed a slightly higher recovery rate (~95%) than 3% KCl brine (90%), and this difference might be due to the higher salt concentrations or increased viscosity of SNF HPP muds. The dispersion test results are sensitive to fluid viscosity; the increased viscosity reduces mechanical erosion and therefore increases the recovery rate (Young and Friedheim, 2009). However, the main purpose of this test here is not to quantify the clay inhibition rate, but rather to ensure that the developed polymer system does not impact the clay cutting recovery negatively. Therefore, more in-depth study is required to evaluate the long-term fluid-shale/clay interactions to properly design the drilling mud to target challenging shale formations, where shale stability and formation damage are big threats to drilling, stimulation, and production operations.



**Figure 9 – Dispersion of reactive clay (Na-bentonite) in different fluid systems.**

### Field Applications

The performance tests have challenged the developed HPPs by exposing them to harsh conditions of temperature, density, salinity, divalent ions, pH, shear, and differential pressure. These harsh conditions present great limitations on the selection of polymeric additives for most field applications (Kippie et al., 2002). The results of this work confirmed the excellent physical and chemical stability of SNF HPP systems under various testing conditions. This performance allows SNF HPP to work in a broad range of applications. The good thermal stability of SNF HPP-1 makes it primarily suitable for conventional drilling operations where salinity and temperature are in the higher mid-range. The great rheological and suspension properties, especially low-end rheology and yield point, give

this polymer high potential to be used for hole cleaning where high-viscosity pills are circulated downhole to remove accumulated cuttings and solid particles. With these suspension properties, this polymer can also be used to provide viscosity to carry lost circulation materials to treat seepage and severe mud losses efficiently. Other environmental applications also include pumping drilled cuttings into disposal wells.

The high salt tolerance of SNF HPP-2 polymer offers great flexibility in field operations. This HPP can be mixed with high-salinity brines to prepare high-density drilling and completion fluids. For instance, calcium bromide fluids can provide a density of ~15 ppg, while with zinc bromide salts, fluid density can reach up to 21 ppg. This flexibility and high thermal resistance widen the drilling and completion windows to target high and ultra-high formation pressures. The good suspension and rheological properties of SNF HPP-2 allow it to be used for directional and extended-reach drilling, especially with long laterals where hole cleaning is challenging. In addition to providing viscosity, the performance test results also showed that this product provides excellent filtration control, while the formed filter cake can be easily dissolved in mid acids such as formic acid. This feature unlocks another potential for this product to be used with drill-in fluids to efficiently drill producing formations. The minimal fluid loss could reduce the fluid invasion into the drilled formation and minimize the formation damage, especially in reactive shale formations.

All these features make the introduced HPP systems viable candidates for wide drilling and completion applications. However, depending on the targeted application, a preliminary study is always recommended before field implementation to optimize the dosage and investigate the compatibility with other additives, especially with HPWBM systems, to ensure successful results.

### Summary and Conclusions

New high-performance polymer systems were developed for drilling and completing oil and gas wells. The new polymers were introduced as viscosifiers for saturated brine with additional fluid loss control function. SNF HPP-1 is intended for conventional drilling operation at mild salinity and temperatures, while SNF HPP-2 is primarily developed to work with HPWBMs, drill-in, and completion fluids under harsh conditions. A thorough evaluation was done in the lab to test both systems' performance at various conditions. The experimental study involved measuring rheological, suspension, and filtration properties. Additionally, the long-term performance was also evaluated by testing thermal stability, shear resistance, and fluid loss for extended time to simulate drilling in long-lateral horizontal wells. Based on the obtained results, the following conclusions can be drawn.

1. SNF HPP systems showed good rheological and suspension properties. Low-end rheology (R3 & R6) varied between 8 and 20 deg. Which was significantly

- reflected in the good sag performance (VSST: 0.5-1.2 lbm/gal).
- Developed polymers exhibited excellent thermal stability with all brine systems used in this study. SNF HPP-1 polymer was stable at up to 250°F, while SNF HPP-2 could withstand 350°F for up to 5 days of hot rolling.
  - Without using a fluid loss control agent, SNF HPP-2 polymer yielded excellent filtration properties with different brines at elevated temperatures. API fluid loss ranged between 7 and 14 mL/30 min, while extending the fluid loss experiment for up to 24 hrs resulted in only ~60 mL filtrate volume. Moreover, above 95% of the formed filter cake could be removed with mild acid solution (10% formic acid).
  - The new polymers also showed a high resistance to shearing. No significant drop in the rheological properties was observed after shearing the polymer solutions for over 5 cycles at  $\sim 30,000 \text{ s}^{-1}$ .
  - The exceptional performance observed with SNF HPP-2 in terms of rheology, suspension, thermal stability, fluid loss control, solubility in mild acid, shear resistance, and salts tolerance make it an excellent viscosifier and fluid loss control product that can be suitable for various drilling and completion applications, especially for challenging downhole conditions.
  - Additional work is required to study the long-term shale inhibition and stability with these polymer systems to evaluate the applicability of such products in challenging shale formations. Testing the regained permeability near the wellbore after removal jobs would also be an interesting area to investigate prior to field applications. Additionally, we recommend looking into the compatibility of these new polymers with other special additives used to design high-performance drilling and completion fluids such as lubricants or other polymeric products to ensure successful results in the field.

## Nomenclature

API=American Petroleum Institute  
 BPU=Bed pickup percentage, %  
 ECD=Equivalent circulating density, ppg  
 HPP=High-performance polymer  
 HPWBM=High-performance water-based mud  
 HTHP=High-temperature high-pressure  
 LSYP=Low shear yield point (2 R3-R6), lbf/100 ft<sup>2</sup>  
 OBM=Oil-based mud  
 PHPA=Partially hydrolyzed polyacrylamide  
 ROP=Rate of penetration  
 R3 & R6=Fann dial reading at 3 and 6 RPM, deg.  
 VSST=Viscometer sag-shoe test  
 WBM=Water-based mud

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