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Innovative drilling fluid containing sand grafted with a cationic surfactant capable of drilling high pressure and high temperature geothermal and petroleum wells

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ABSTRACT

Maintaining the rheology and filtration properties of a drilling fluid plays a vital role during a drilling operation. With the current challenges of high pressure and high temperature environments, there is an urgent need to design thermally stable water-based mud systems (WBM) which are environmentally clean and economically cheap.

High pressure and high temperature (HPHT) environments affect drilling fluid systems leading to degradation of additives hence reducing the efficiency of the drilling fluid. Nanotechnology has been widely used to answer questions about additive degradation, and many studies are currently being conducted on how to use nanotechnology to design smart drilling fluids. However, nanotechnology comes at a high cost, resulting in an increase in the overall drilling operation costs and the project as a all. Therefore, the effectiveness of sand particles as a replacement of commercial nanoparticles is investigated in this study as an additive for designing effective-performance water-based drilling fluids. Effective-performance drilling fluids are environmentally friendly, stable at high temperatures, and help to avoid well damage during drilling operations.

The research compared sand particles, which are widely available and inexpensive to silica nanoparticles at 0.5 wt% concentration. The samples were tested at different aging temperatures. Rheological properties were measured at room temperature up to 232 °C. The performance of sand and silica nanoparticles was studied by comparing each of the nanoparticle muds with the reference mud sample, taking filtration and rheological properties as the benchmark parameters. Experimental data showed that sand particles enhanced almost all the rheological and filtration properties of the WBM compared to the reference mud. When compared to silica nanoparticles, the results showed neither statistically significant variance in plastic viscosity and yield point among the samples, with muds containing sand particles performing similarly or better. Formulation S2 (35–70 μm) demonstrated the ability to improve the rheology of WBM. At 204 °C and 232 °C, Formulation S2 (35–70 μm) filtrate loss decreased by 16.35% and 29.52%, respectively, compared to 5.66% and 11.32% by mud containing nano silica. The same mud sample decreased the mud cake thickness at the same temperatures conditions by 54.74% and 45.45%, respectively, as opposed to 36.84% and 11.81%. The new innovative mud system can be used to drill in HPHT conditions.

1. Introduction

Geothermal wells are the key to unlocking and harnessing the earth's heat for the production of clean environmental and sustainable energy. The growing concern about environmental pollution caused by drilling operations as well as the global increasing demand for energy and the challenge of ensuring that the world achieves the energy trilemma of energy sustainability, energy affordability and energy security has led to an increase in geothermal exploration and drilling activities over the years. However, unfriendly downhole conditions and drilling fluid systems used have had an impact on drilling operation activities posing serious challenges to drilling companies. These challenges are related to equipment and downhole failure, drilling fluid degradation and failure, difficult cementing and casing jobs and many more. As a result, the

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drilling industry has been pushed to its limits in terms of additive selection, with an increase in the demand for highly developed technologies and equipment (Finger and Blankenship, 2010a,b). Moreso, a drilling fluid exhibits neither Newtonian fluid behaviour nor Bingham plastic behaviour therefore, achieving accurate predictions for parameters like plastic viscosity (PV), yield point (YP), and apparent viscosity (AV) in high-pressure, high-temperature (HPHT) conditions is essential. However, the scarcity of sensors capable of measuring elevated pressure and temperature in downhole environments poses a challenge. Traditional sensors may not withstand extreme temperatures, pressures, and corrosive environments, limiting the availability of direct measurements. In the case of drilling fluids, engineers depend on the use of soft sensors to predict rheological parameters in situations where direct measurements are challenging (Gautam et al., 2021). The current oil and gas drilling technologies are widely adopted in geothermal drilling operations even though the characteristics of the geothermal wells may led to significant increase in cost and time required (Allahvirdizadeh, 2020; Carson, 1982). Geothermal drilling is similar to oil and gas drilling in concept, but what distinguishes it from oil and gas drilling is the manner the well is designed. (Sumardi et al.). The petroleum industry is no stranger to well construction in unfriendly environments and it has become a benchmark in drilling high pressure and high temperature (HPHT) wells. Different definitions for HPHT wells have been proposed. The American Petroleum Institute (API) defines it as a well with a pressure above 15,000 psi and temperature greater than 177 °C, Whereas NORSOK defines it as a well with a shut-in pressure above than 10,000 psi and bottomhole temperature above than 150 °C. Whoever, these definitions are different in geothermal operations as reservoir temperatures get as high as 300 °C with plans to venture into wells with 500 °C in the coming years. This therefore presents a completely different technological challenge from the HPHT environment operated in by oil and gas industries. Drilling geothermal wells has been found to be more costly compared to drilling oil and gas wells (Bavadiya et al., 2019; Vollmar et al., 2013). Further to the temperature differences, there are other differences in constructing geothermal wells and oil and gas wells. These include, risks of losses when highly fractured formations are drilled, usually large hole sizes in order to facilitate flow when producing heat, geothermal wells tend to need the drilling of harder and more abrasive formations: rigid sedimentary formations and volcanic (Vollmar et al., 2013). The presence of very high pressures and temperatures creates a serious challenge for the design of drilling fluids and application of completion equipment (Clegg and Krase, 2022). Thermal stability is a critical property for geothermal drilling fluid additives. The high temperatures found in geothermal wells promote thermal degradation of polymeric additives used in drilling fluids. Degradation can reduce the performance of drilling fluid, reducing drilling fluid efficiency and increasing drilling time and cost (Hamad et al., 2020). Bentonite drilling fluids are frequently used in drilling geothermal wells. However, at high temperatures, clay flocculation induces an undesired shift in mud viscosity. (Martin et al., 2022a).

A drilling fluid system is a crucial factor for a well's success or failure while drilling wells. A drilling fluid system also plays a vital role in reducing the cost of the overall budget of the project. Therefore, selecting a drilling fluid system which is thermally stable, environmentally friendly, and cheap is a key preference to most drilling companies. Geothermal wells utilize the earths heat to generate energy therefore, high temperatures and pressures are encountered which sometimes are extremely very high. Geothermal drilling fluid systems can be easily adapted to drilling oil and gas wells. As a result, when selecting mud additives, the rheological behaviour and thermal stability of the mud system are critical factors to consider, especially when drilling in HPHT conditions. The drilling fluid system should be able to lift and transport the cuttings to the surface, control the well pressure, prevent a kick, lubricate, and cool the bit etc. It is known that HPHT conditions promote thermal breakdown of polymers used in the drilling fluid. The breakdown leads to poor performance of the mud system which directly reduces drilling fluid efficiency and results to increase in cost and time (Martin et al., 2022b). Therefore, environmentally friendly but equally or better performing additives are needed. Currently, companies are investing heavily in research that can come up with cheap but efficient additives. Nanotechnology has been adopted widely in the drilling industry as a replacement to polymer additives. This is because nanoparticles have been found to be thermally stable with efficient plugging and loss of circulation abilities but the technology is expensive and costly (Kulkarni et al., 2013). Due to the limited number of drilled wells in the geothermal industry in comparison to the petroleum industry, and the luck and uncertainty of operational and drilling data in geothermal projects, the geothermal industry has been reluctant in researching HPHT well conditions which is another problem in the geothermal industry (Kruszewski and Wittig, 2018). In the United States, for example, fewer than 100 geothermal projects were drilled in 2008, but thousands of oil and gas wells were drilled in the same year (Bavadiya et al., 2019). This unpredictability requires the transfer of experience and technology from the oil and gas industry to fill gaps and improve drilling efficiency.

1.1. *Associated problems with geothermal drilling fluid rheological stability*

Drilling operations are greatly impacted by chemical and physical stability of drilling fluid. Physical stability of drilling fluid refers to its ability to withstand downhole physical conditions encountered during drilling and circulation, such as HPHTs and excessive shear forces. (Basfar et al., 2019). In contrast, chemical stability refers to the resistance of the drilling fluid to the chemical interactions caused by the contaminants and components of the drilling fluid. (Bageri et al., 2020; Mahmoud et al., 2019). The existence of high temperatures in geothermal wells poses a significant barrier to drilling fluid. It accelerates the heat decomposition of polymeric additives and deteriorates the drilling fluid's rheological characteristics (Amani and Al-Jubouri, 2012; Avci and Mert, 2019). Furthermore, bentonite mud flocculation caused by HPHT conditions presents serious challenges to geothermal drilling fluids. High temperatures accelerate the thermal breakdown of polymer additives and reduces the rheology of the slurry liquid. This change is frequently noticed at temperatures exceeding 121 °C (Zilch et al., 1991). These challenges still exit during geothermal drilling operations hence need addressing.

1.2. *Drilling fluid advancements in geothermal wells*

Most of the drilling fluid used in the early stages of geothermal drilling consists of water and bentonite clay. (Erge et al., 2020). Other additives have been added such as polymeric additives to maintain and improve the mud rheology and filtrating characteristics (Chemwotei, 2011; Finger and Blankenship, 2010a,b). Though Oil-based drilling fluid fluids (OBMs) have performed better compared to water-based muds (WBMs) in regard to thermal stability and mud efficiency, WBMs are still preferred and are more commonly found in geothermal drilling operations due to environmental concerns, stringent restrictions and high costs associated with OBM (Amani and Al-Jubouri, 2012).

The earliest geothermal well in California's Imperial Valley was drilled with clay mud. At temperatures exceeding 121 °C. Clay flocculation caused an unwanted change in rheological characteristics. Eventually, the sludge system was treated with lignosulfonate, but the treatment failed. (Zilch et al., 1991). As a result, the industry began to look for alternate ways of replacing bentonite fluids. Initially, sepiolite clay was used instead of bentonite since it has higher thermal stability. Despite this, sepiolite clay was unable to manage the drilling fluid's filtration characteristics. Low bentonite concentrations and Several polymers were added to sepiolite mud to solve the filtration problem. (Altun et al., 2010). To retain the rheology and filtration characteristics, a variety of treatments were carried out with increased lignite and bentonite concentrations. Due to the degradation of lignite caused by high temperatures and pollution, this overtreatment resulted in a high viscosity rise (Zilch et al., 1991). A mixture of bentonite and polymer was proposed as an option for geothermal drilling to reduce the cost of polymer-based drilling fluids while enhancing the effectiveness of bentonite muds (Chemwotei, 2011). Furthermore, because traditional deflocculants, thinners and viscosifiers degrade at elevated temperatures above 176.6 °C, several research projects are presently focusing on developing the next generation of drilling rheology control additives that are more thermally robust, environmentally friendly, and cheap. (Thaemlitz et al., 1999; Tuttle, 2005). Various nanoparticles have been added to drilling fluid systems in numerous attempts aimed at enhancing the properties of muds. These experiments demonstrated that nanoparticles (NPs) could considerably enhance the filtration and rheological properties of drilling fluid fluids, as well as assist reduce issues like, fluid instability, hole cleaning and lost circulation that are linked with drilling fluid rheology (Boyou et al., 2019; Hajiabadi et al., 2019; Pakdaman et al., 2019). Nanotechnology as mentioned earlier comes with a high cost therefore, other alternatives need to be introduced in order to keep drilling costs under control.

1.3. *Challenges of nanotechnology in geothermal drilling*

Though the use of nanoparticles can give considerable technical benefits, there are several drawbacks to using nanomaterials in drilling fluids. The price of nanoparticles is an important consideration before starting a project. Overall, the production process and synthesis of nanoparticles can be quite costly, and a large volume must be used in the drilling operation, which increases drilling costs. Other major challenges include the different well conditions and unique features of each well, and the compatibility of nano drilling fluids and nanomaterials in them. High temperatures, chemical changes, and salinity can all be detrimental to nanomaterial structure in specific formations. Furthermore, the unknown safety hazards and health risks associated with nanomaterials should be of concern to the industrial users of nanomaterials (Bianchi et al., 2019; Hoet et al., 2004). Recent research has shown that some nanomaterials can cause cancer and fibrosis (Bianchi et al., 2019; Martin et al., 2023; Tsuda and Alexander, 2019). As a result, application of conventional industrial hygiene practices during drilling operations may greatly improve safety and protection when using nanoparticles in drilling operations. Because nanotechnology is a newer technology for developing new drilling fluids, there are fewer experimental and field testing, analyses, knowledge, and experience on its long-term performance and health effects. (Cheraghian and Afrand, 2021). Therefore, more studies are still needed to establish the toxicity, effects of nanomaterials to human health and the ecosystem.

1.4. *Other geothermal drilling fluid additives*

Wellbore strengthening involves adding particles to a drilling fluid in order to seal induced cracks, allowing for a higher wellbore pressure to be maintained. Most models show that larger solids are required to achieve a stronger strengthening effect (e.g., as depletion worsens), this has led to the use of 1 mm or larger particles in several applications. These big solids can cause problems in the field (Chellappah et al., 2015). Other problems include particle attrition, settling, tool plugging, and erosion, in addition to the difficulties of retaining material owing to screen-out at the shakers. The wellbore strengthening material's tendency to agglomerate or swell in the drilling fluid, thereby increasing its particle size, should also be taken into account.

Several researchers have studied material type E.g., (Grant et al., 2016; Growcock et al., 2012; A. Kumar et al., 2010; Valsecchi, 2014) with an interest on particle degradation. They study's main conclusion was that marble commonly used as a strengthening wellbore material easily degrades by shear. Also, large particles have a higher tendency to grind down than smaller ones (this is connected to the Archimedes number, which is related to particle size and density differential between particles and fluid) (Chellappah et al., 2018). Because of the increased degradation with size, maintaining marble larger than roughly 400 μm in a circulating system can be difficult, necessitating addition rates of over 100 bags per hr. (Chellappah et al., 2015) conducted a laboratory experiment testing two different types of materials: marble and walnut shell. Walnut shell was found to have a substantially better attrition resistance and less erosive than marble. It had a lower density and hence was less prone to settle, as well as performed better in fracture sealing tests (Chellappah et al., 2015). PAC- grafted copolymers were investigated in water-based mud (WBM) by (Gautam and Guria, 2020b). The authors determined that, when subjected to high-pressure, high-temperature (HPHT) conditions, the effectiveness of mud could be significantly enhanced by manipulating the molecular weight of PAC-grafted copolymer. The mud was also found to be environmentally friendly. The rheology and filtration properties of functionalized fly ash in aqueous suspension involving tamarind gum and polyanionic cellulose were studied and compared with API-grade drilling bentonite. The thermal stability, cuttings transportation ability was evaluated under downhole condition at 75 °C and 100 psi. The authors concluded that functionalized fly ash was found to be cost effective over API-grade bentonite. Furthermore, the investigation indicated that both functionalized ash and bentonite muds displayed similar filtrate properties. The rheological characteristics were noted to enhance as the concentration of functionalized fly ash increased (Gautam et al., 2018). Therefore, this study intends to evaluate the thermal stability and rheological behaviour of a different environmentally friendly, cheap additive grafted with a surfactant to ascertain its performance in HPHT conditions.

1.5. *Bentonite clays in drilling fluids*

Clay materials in drilling fluids such as bentonite as shown in Fig. 2 always have their platelets arranged in a face-to-face (F– F) association when in reaction with moisture or water or in their dry state without applying any shearing or agitation to them, forming a structure that resembles a deck of cards. This state is referred to as aggregation. When high shear rates are applied, the hydrated and swollen packets are broken apart into individual platelets, which are then disoriented and evenly distributed within the suspension, a process known as dispersion. This state will be maintained and improved as long as the shearing force exists. In the meantime, once the shearing force is removed, the colloidal suspension of clay platelets will be slowly attracted to each other forming an edge-to-edge (E– E) or edge-to-face (E– F) association or a combination of both resulting in a structure resembling a house of cards (Benna et al., 1999; Edalatfar et al., 2021). This state is referred to as flocculation. Edge-to-Face (E– F) interactions are caused by electrostatic attractions between the opposite charges of the edges (+) and faces (−) of the particles. Oftentimes, a chemical thinner known as a deflocculating agent is sometimes applied to neutralise the positive edge charges on the clay platelets and the colloidal suspension will then be in a deflocculated state. When strong electrolytes are existent in the clay suspension, the cations are adsorbed on the clay surface, reducing the hydration bond with the water molecules and promoting a higher degree of flocculation or even the formation of stronger aggregates when water is completely dispersed from the interlayer surfaces of the platelets (Caenn et al., 2011; Garrison, 1939; Garrison and Ten Brink, 1940). Therefore, the dispersion of bentonite clays is explained by two mechanisms: (I) the strong electrostatic attraction between positively charged edges and negatively charged faces (E– F) and (II) the E-E and F-E interactions via long range electrostatic double-layer repulsion (Callaghan and Ottewill, 1974). These interactions and associations may be responsible for the customization of bentonite clay dispersions, effective rheological properties, and they are significantly influenced by temperature.

2. Materials and methodology

In the experimental research, the following materials were used mainly: Distilled water Polyanionic-Cellulose (Pac) for controlling filtrate loss was obtained from Fisher scientific UK, cetyltrimethylammonium (CTAB) which is a cationic surfactant, barite for viscosity modification, bentonite which is the most commonly used clay in drilling fluids, sand (149–420 μm) and (35–70 micro), silica NPs (67.45 nm) and (149 nm) for rheological improvement were used to design the mud samples. Details of the materials are listed in Table 1. The rheological and filtration properties were analysed by the M1100 viscometer and HPHT filter press. Equipment used are shown in Fig. 3.

2.1. The reaction processes

The pH value was maintained at 10 by adding 0.1 M NaOH to enable enough hydroxyl groups to occur on the sand surface. The charge polarity observed in sand has been found to be influenced not only by particle size but also by the particle size distribution (Yu and Xie, 2017; Zheng et al., 2003). This suggests that the distribution of particle sizes within sand plays a significant role in determining the charges it carries. Furthermore, It was observed by (Gu et al., 2013; Zheng et al., 2003) that sand particles with a diameter exceeding 500 μm tend to carry positive charges, whereas those with a diameter less than 250 μm carry negative charges. Since sand surface charge was negative (Stenkamp and Benjamin, 1994), addition of CTAB to the system led to formation of the organic chain of CTAB array around sand due to the ionic interaction between the negative and positive charges on the surface of sand. Lastly, cation reacts with the hydroxyl groups on the sand surface resulting in the surfactant being grafted on the sand surface and thus lowering the surface energy of sand. On the other hand, after the organic chain of CTAB grafting on the surface of sand, the steric among the sand surface increases resulting in a more mono-dispersed colloidal solution. As a result of these factors, the stability of sand increases and the dispersed state improves (Ma et al., 2010).

2.2. Preparation of drilling fluid samples

The drilling fluid samples were prepared following the API RP 13B-1 2009 standard (RP, 2009). As presented in Fig. 1, 350 mL of distilled water was mixed with 22.5 g of bentonite clay and 20.3 g of barite for 20 min. After, 0.5 g of PAC was added to the mixture and stirred for 10 min. After, 0.5 g of silica nanoparticles and 0.5 g of sand particle with 2 g of CTAB were added and stirred for another 10 min. The solution was finally stirred for 5 min to create a homogeneous solution. The mixing of the mud took a total of 45 min. The Hamilton-Beach mixer was tasked for mixing the drilling fluid. The pH was kept at 9.5 for each formulation for better chemical reaction and stability of the colloidal solution. The pH was also adjusted back to 9.5 after aging. Table 1 presents the materials used for mud formulation.

The same procedure was followed for all the drilling fluid samples prepared. The mud samples were labelled S1, S2, S3, S4, and S5. Water based mud (WBM) without nanoparticles was labelled the reference mud (S1), S2 formulation contained modified sand particles (35–70 μm), S3 formulation contained modified sand particles (149–420 μm), S4 formulation contained nano silica (67.45 nm) and S5 formulation contained nano silica (149 nm). The samples were analysed under two conditions: low pressure and low temperature (LPLT) and high pressure and high temperature (HPHT). The samples were dynamically aged in the roller over for 16 h and measurements of yield point, plastic viscosity, gel strength and filtrate loss were taken respectively after aging. Table 2 below presents the different formulations designed for this study.

2.3. Rheological properties measurement

The experimental study was carried out in compliance with the API Recommended Practise 13 B (API, 2004) as the standard for drilling fluids testing procedure. The automated viscometer M1100 was tasked to evaluate the different rheological properties of drilling fluids at a temperature of 25 °C. Operated with ORCADA software, the fully automated Model 1100 pressurized viscometer shown in Fig. 3 d was used to measure the yield point (YP), plastic viscometer and gel strength. Fluid samples underwent testing both before and after being aged for 16 h at elevated temperatures. Following the elevated temperature aging, all samples were subsequently cooled down to room temperature. They were then re-mixed for 5 min at 400 rpm using a propeller mixer, pH adjusted, and the rheological properties were determined. To ensure the reliability and consistency of the results, the tests were repeated three times. Plastic viscosity, yield point, as well as gel strength, were determined as parameters of the Herschel-Bulkley model. From the values of the best fit model parameters, the Bingham plastic and Power law models give wildly different predictions at particularly low shear rates meaning very high yield point in Bigham plastic, very high k value and low n value in Power law. This data fits the Herschel-Bulkley model better which contains Bigham plastic and Power law. The gel strength was tested after shearing for 10 s at 600 rpm. Prior to testing, the samples were agitated for 5 min at 11,500 rpm, giving them the same preshearing history. Filtrate loss analysis was conducted at both room temperatures and at elevated conditions using the HPHT filter press at 100 °C and 500 psi. The weighing scale was used to measure the filtrate collected, and a Vernier-type calliper was used to evaluate the filter cake thickness.

Table 1
Drilling fluid preparation materials.

Components	Composition	Purity	Molecular weight (g/mol)	Density (kg/m^3)	Brand	Purpose
Bentonite	22.5 g	80–90%	180.1	600–1100	Fisher scientific UK	Filtrate loss preventer, Viscosifier
Barite	20.3 g	98%	233.4	4500	Fisher scientific UK	weight material
polyanionic cellulose	0.5 g	>98%	1.146	0.7–2.85	Fisher scientific UK	Filtrate loss preventer,
Hydrochloric acid (HCl)	0.1 g	37%	36.46	1200		pH modifier
Sodium Hydroxide (NaOH)	0.1 g	99%	39.997	2130	Fisher scientific UK	pH modifier
Flash water	350 mL	–99.96%	18.015	1000	–	Base fluid
Hexadecyltrimethylammonium bromide (CTAB)	2.g	>95%	364.45	500	SLS-Sigma-Aldrich	Surface charge modifier
Sand	0.5 g	>95%	60.08	–	Fisher scientific UK	Rheology enhancer

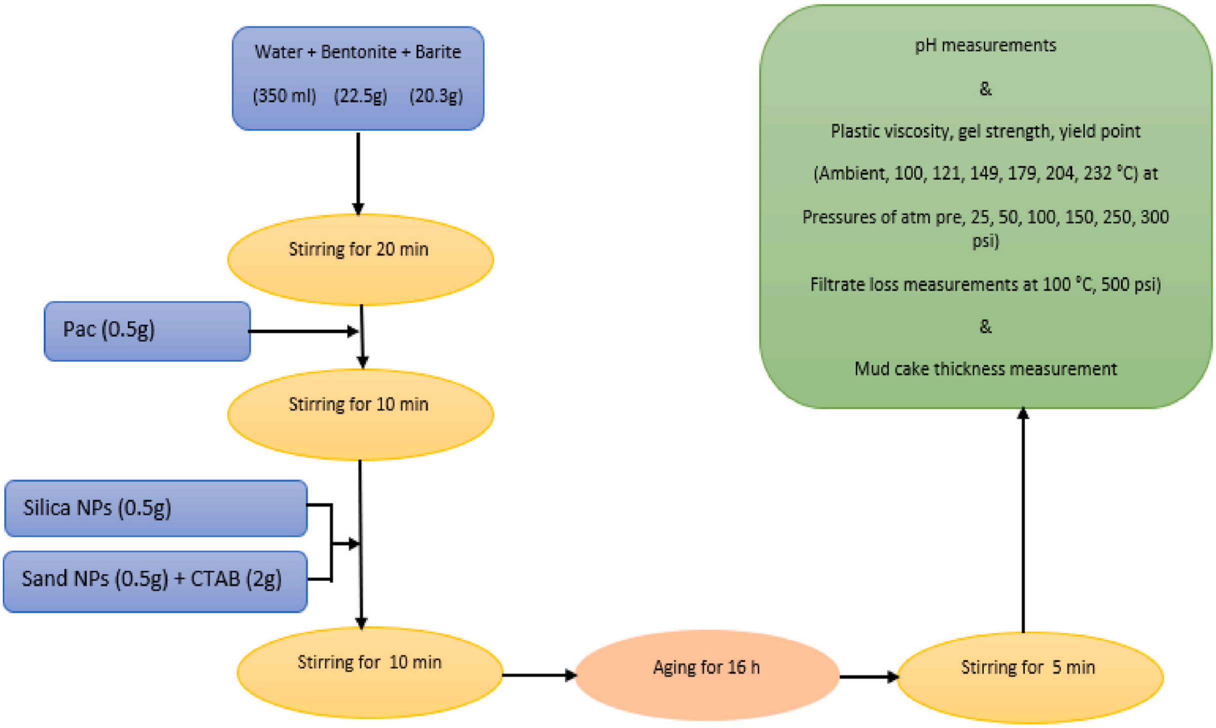


Fig. 1. Experimental methodology procedure.

3. Results and discussion

Table 3 presents the measured data at both room temperature and elevated conditions. It is evident that mud samples with sand particles had the lowest PV compared to other mud samples. Hexadecyltrimethylammonium bromide (CTAB) which is a Cationic surfactant was attached on the surface of sand to invoke Steric Stabilization. The attachment of long chain-molecules can be achieved by chemical synthesis also referred to chemical grafting or by adsorption (Chhabra and Shankar, 2017; Napper, 1977). In this case, steric stabilization was achieved due to adsorption of surfactant molecules on the surface of sand particles. The aim was to increase the surface area of sand and improve its chemical reactivity. The cationic surfactant attached increased the positive charge on the surface of sand particles. This then improved the colloidal stability leading to improved rheology. Maintaining a consistent viscosity under elevated temperatures suggests that sand particles have the capacity to impede a reduction in viscosity, thereby exhibiting uniform rheological behaviour across different temperature ranges. This phenomenon is attributed to the interaction between negatively charged bentonite and positively charged sand, resulting in the formation of larger particles within the mud system. Consequently, as the particle size increases, the viscosity decreases, indicating an inverse relationship between particle size and viscosity in this context (AR Ismail et al., 2016).

This means that sand particles caused a reduction in bentonite swelling abilities compared to silica nanoparticle muds and the reference mud. Temperature effects were evident, as increasing temperature increased the PV of all mud samples, though there was a steady increase in PV with muds containing sand particles.

With increasing temperature, yield point of all mud samples varied significantly. When compared to a mud with a lower yield point, one with a higher yield point will have stronger cutting carrying abilities and will suspend the cuttings better. Mud samples containing silica NPs or sand particles displayed high yield point than the reference mud at almost all tested temperatures although at room temperature, the reference mud had a higher yield point. Gel strength of almost all muds improved as temperature increased though mud samples containing silica nanoparticles had greater gel profiles after a temperature of 121 °C. Both the control mud and muds containing sand particles showed a non-monotonic pattern when temperature increased above 121 °C, with muds containing sand particles exhibiting stable gel profiles at temperatures over 149 °C. On average, drilling fluid containing sand particles reduced filtrate loss when compared to other mud samples, with the control mud performing better or similarly to mud formulations containing silica nanoparticles. On average, mud formulation S2, with sand particles sized between 35 and 70 μm, consistently displayed the lowest filtration loss compared to other mud formulations as temperature increased. However, there were exceptions at temperatures of 26.3 °C and 176 °C, where it exhibited slightly higher filtrate loss. A thinner filter cake was produced by sand particle muds than that produced by silica nanoparticle mud and bentonite mud samples, particularly mud S2 with sand particles of size (35–70 micro) exhibited a thinner filtrate cake.

3.1. *Rheological curves at different temperatures*

Shear stress values of the mud formulations are presented in Fig. 4 at both ambient and higher temperatures. From shear stress verses shear rate curves, the mud formulations behaved as plastic fluids at 26–232 °C. According to Fig. 4, shear stress and shear rate relationship is nonlinear between 0 and 300 rpm, however linearity increases up to 600 rpm; hence, the two-parameter Bingham plastic model, that assumes a linear relationship between shear stress and shear rate, can partially represent the behaviour of these mud samples. However, this model does not accurately represent the behaviour of the drilling fluids at low shear rates. Unlike the Bingham plastic model, the power-law model assumes a non-linear relationship between shear stress and shear rate. The Herschel-Bulkley fluid model fits the behaviour of the mud samples after aging because it assumes the fluid stress to be related to the strain in a nonlinear way. It is the desirable model for predicting shear thinning behaviour of the formulations. The model gives a more accurate mathematical explanation of viscosity than the power law, which excludes the drilling fluid's yield stress. The Herschel-Bulkley model is represented as:

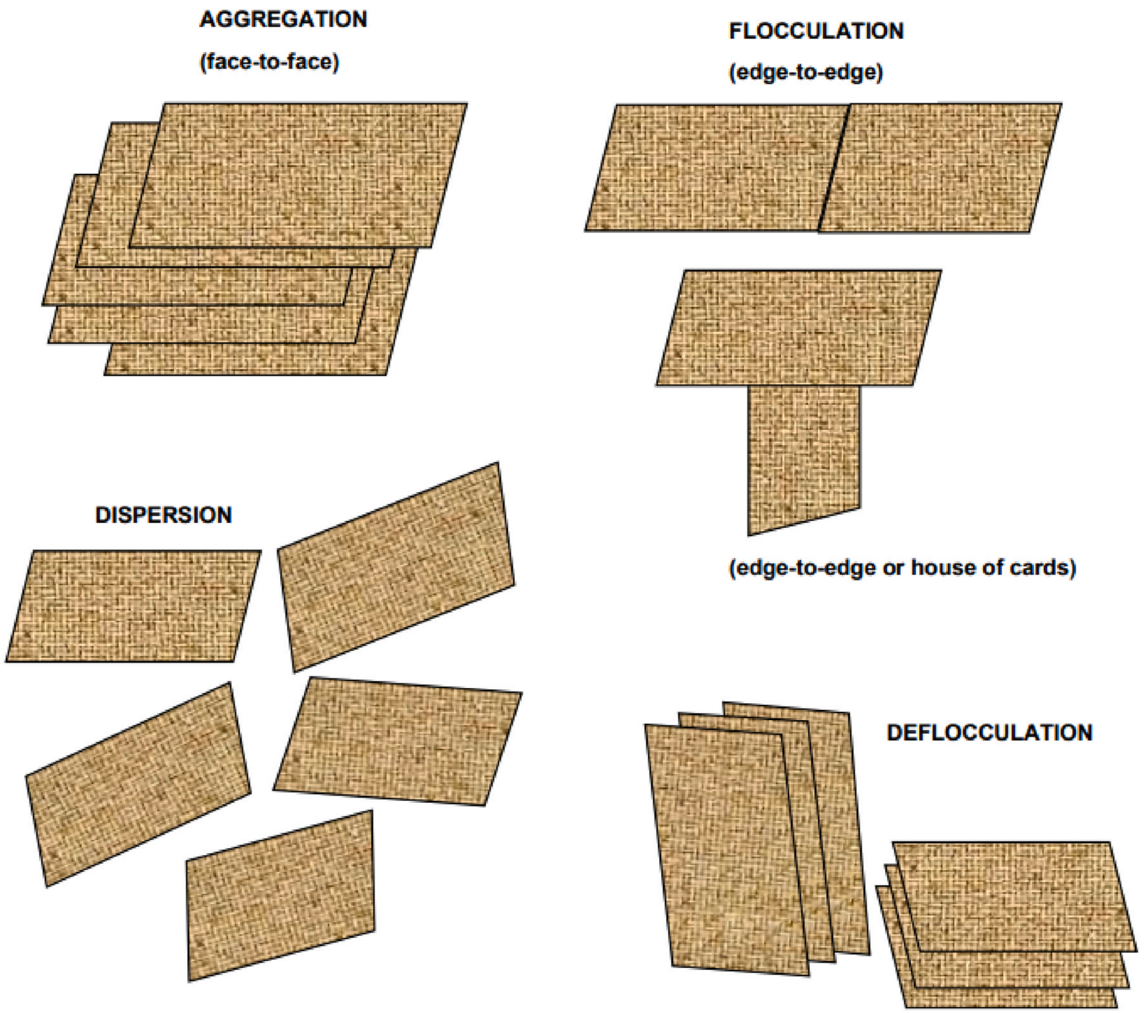


Fig. 2. Simplified illustration on the types of platelets associations.

$$\tau = \tau_o + k\gamma^n. \tag{1}$$

Where τ = shear stress, τ_o = yield stress, k = constant factor, γ = shear rate and,

n = flow index, a power law exponent.

The Bingham plastic model is ideal for continuous drilling fluid monitoring and treatment. A fluid that displays Bingham plastic behaviour remains stationary until the shear stress exceeds a critical number known as the yield point. Once the critical point is reached, changes in shear stress and shear rate will be proportional. This proportionality constant, or the slope of the curve, is known as plastic viscosity. Fig. 4 shows a non-monotonic pattern in the behaviour of the mud samples with changes in the temperature. Temperature increase affected mud formulations differently with some mud formulations exhibiting a shear thinning effect while other samples showed a shear thickening effect. Shear thinning behaviour is desired because it reduces pumping pressure and increases the rate of penetration when the viscosity in the pipes is low and shear rate of the drilling fluid is high.

From Fig. 4, higher temperatures led to higher shear stresses especially when nanoparticles were added at high shear rates. Nanoparticles acted as chain joiners by reinforcing the bonds between the polymer matrix. Effective hole cleaning is attained once the yield point and gel strength are as low as possible. A lower yield point indicates reduced gel strength, making the fluid more conducive to initial flow and facilitating the efficient transport of drilled cuttings to the surface. (Saasen and Løklingholm, 2002). Increase in YP with temperature was due to bentonite flocculation in the presence of nanoparticles. At low shear rates, shear stress rose when temperature increased and there was divergence of shear stresses towards different values for formulations in Fig. 4 (b), (c), (d) and (e). On the contrary, Fig. 4 (a) showed that, there was a convergence of the shear stress towards similar values at least for the temperature tested. This behaviour suggests stability of the mud formulation. Stable viscosity profiles with increase in temperature indicates sand's ability to suppress viscosity reduction thereby yielding identical rheological behaviour with varying temperatures.

3.2. Initial conditions (time-dependence) and wall slip effects

To prevent the settling of particles when drilling operations are temporarily halted, most drilling fluids undergo a gelling process, forming a microstructure over time when left undisturbed. In the field, drilling fluid gel strength is measure by a viscometer first by breaking down the structure of the fluid at high shear rate then letting the fluid rest for a specific period typically 10 s or 10 min. Following this period of quiescent, the fluid is subjected to a shear rate step from 0 s^{-1} to 5.1 s^{-1}. The gel strength is recorded as the maximum shear stress during start-up for flow.

However, even though it is well accepted that API procedures should be followed for industrial purposes, there are still scientific questions regarding to gel strength measurement rest period. It is true that drilling fluid is time - dependent yield stress material therefore its ability to yield or flow under stress is influenced by time. Research has concluded that there might be limitations with the 10 s rest period as a time for microstructure rebuilding. From the research done by (Maxey, 2011),

Fig. 3. (a) Hamilton beach mixer (b) Aging roller oven (c) API HPHT filter press and (d): M1100 viscometer set up for rheological measurement.

Table 2
Drilling fluid formulations.

Sample	Abbreviated Name
350 mL water + 22.5 g Bentonite +20.3 g Barite + 0.5 g PAC	S1
350 mL water +22.5 g Bentonite +20.3 g Barite + 0.5 g PAC + 0.5 g Sand (35–70 micro) + 2.0 wt% CTAB	S2
350 mL water + 22.5 g Bentonite +20.3 g Barite + 0.5 g PAC + 0.5 g Sand (149–420 μm) + 2.0 wt% CTAB	S3
350 mL water + 22.5 g Bentonite + 20.3 g Barite + 0.5 g PAC+ 0.5 g Silica (67.45 nm)	S4
350 mL water + 22.5 g Bentonite + 20.3 g Barite + 0.5 g PAC + 0.5 g Silica (149 nm)	S5

the author attempted to answer the issue of validity of the gel strength as measured by the standard API procedure by carrying out a simple test. They tested the gel strength of mud samples on a Model 35-type viscometer. They repeated a similar test on a MCR501 rheometer, where the sample was sheared, allowed to rest for 10-s, 10-min, or 30-min and then a shear rate of 0.1 s^{-1} was applied in the API test and the maximum overshoot recorded as measured gel strength. From the study, the authors observed that the gel strength calculated from experiments (after 30 min gel time) was close to the 10-s API gel strength, but less than half the 30-min API gel strength. However, the findings raised serious questions about the reliability of employing the API gel strength measurement technique for estimating downhole pressure drops during gel breaking and flow initiation. While the outcome is not unexpected, it does raise concerns about the validity of this particular measurement approach (Maxey, 2011). Furthermore, (Abedi et al., 2019) in their work examined the destruction-construction of a time-dependent yield stress material, to establish a constant initial condition. From the experiment, the authors stated that for a time-dependant yield-stress material under investigation, the minimum time for parallel storage and loss moduli, G′ and G" (time for microstructure rebuilding) was over 20 min. Therefore, for this material, it took longer than 20 min to construct the microstructure, while for another one it might take less than 10 min to do so. This could affect API testing procedure though the industry still uses API standards to estimate gel strength readings take at 10 s and 10 min. This might present a limitation to the industry's utilization of the API testing procedure.

(Abedi et al., 2019) conducted research to explore the connection between the minimum axial pressure gradient necessary to initiate flow startup and the rheological properties of materials, with a particular focus on the yield stress. The author stated that although the use of model materials offered valuable insights into the startup problem, it was essential to note that the microstructures of these model systems

Table 3
Rheological properties of drilling fluid samples at elevated condition.

Drilling fluid	Temp. (^{o}C)	Pressure (psi)	Plastic Viscosity (cP)	Yield Point (lb/100 ft^2)	10 s Gel (lb/100 ft^2)	30 min Filtrate loss (mm)	Cake thickness (mm)
S1	26	14.7	11.5	16.5	9.5	9	0.35
	100	25	18.02	14.99	11.75	9.7	0.4
	121	50	19.5	12.58	6	16.7	0.5
	149	100	25.9	5.66	6.2	17.5	0.55
	176	150	26.20	6.3	3	19.6	0.89
	204	250	27.30	7.1	4.5	20.85	0.95
	232	300	26.82	7.3	37.37	25	1.1
S2	26	14.7	9	12	7	9.83	0.38
	100	25	9.7	14	7.6	8.45	0.32
	121	50	12.7	14.3	5	10.18	0.35
	149	100	13	6.5	6	14	0.4
	176	150	15.8	19.4	6	19.68	0.55
	204	250	17.7	11.3	6	17.44	0.43
	232	300	18.8	12.25	6	17.62	0.6
S3	26	14.7	10.6	8.6	24.8	9.6	0.35
	100	25	11.5	25	12	14.1	0.5
	121	50	14.8	19.3	15.3	12.3	0.58
	149	100	19.6	28.5	19.8	16.5	0.56
	176	150	20.9	35.6	13	15.1	0.72
	204	250	22.7	11.1	8.8	19.9	1.1
	232	300	19.7	11	7.5	24.3	1.32
S4	26	14.7	14.69	8.19	5.3	9	0.2
	100	25	30.65	10	8	13	0.6
	121	50	26.10	13.2	5	14.5	0.6
	149	100	26.20	13.5	22.5	19.06	0.65
	176	150	28.50	11.3	22.65	17.4	0.67
	204	250	30.90	10.2	24.5	20.22	0.72
	232	300	32.60	9.2	27.7	22.95	0.85
S5	26	14.7	10.79	7.86	5	8.67	0.3
	100	25	25.10	16.94	4	10.06	0.4
	121	50	22.42	33.76	11.67	13.43	0.63
	149	100	21.89	46.25	25.67	21.81	0.8
	176	150	16.23	23.79	27	23.87	0.5
	204	250	14.33	34.15	35.23	19.67	0.6
	232	300	13.12	59.74	41.25	22.17	1.23

generally did not capture all the complexities present in waxy crude oils. Therefore, it may not be appropriate to extend the results and conclusions obtained from these studies directly to field applications. Yield stress materials can fall into either the non-thixotropic or thixotropic category. In the context of non-thixotropic yield stress materials, the microstructure rapidly returns to equilibrium after a stress change, achieving a new state where the structuring level remains constant. In the case of thixotropic yield stress materials however, they display a time delay between the stress change and the achievement of the appropriate structure level (de Souza Mendes, 2009, 2011; de Souza Mendes and Thompson, 2013). According to (Gautam and Guria, 2020a), the authors stated that real-life drilling fluids often deviate from Newtonian behavior, commonly having a finite yield stress. The reliability of the commonly used simple shear-rate equation for monitoring drilling-fluid rheology becomes questionable in such cases. The presence of a fluid with a sufficiently high yield stress and an unsheared plug flow region near the cup further complicates the estimation of shear rate. Additionally, inaccurate values of true yield stress can lead to poor estimates of shear rates at various rotor rotations (Gautam and Guria, 2020a).

Numerous techniques have been developed for assessing yield stress, each possessing its own advantages and drawbacks. However, there is no universally accepted standard procedure for determining yield stress (Dzuy and Boger, 1983; Nguyen and Boger, 1992; Pashias et al., 1996). The central challenge lies in the fact that, as per its definition, yield stress is dependent on the duration one is willing to wait for a potential initiation of flow following a stress change. This dependency remains consistent irrespective of the employed measurement method (Abedi et al., 2019). In practical terms, the waiting time should ideally be at least equivalent to the time characteristic of the process under consideration (de Souza Mendes and Thompson, 2013).

Another limitation is the apparent wall slip which is a common phenomenon in the flow of yield stress materials. If not mitigated, it can give rise to substantial errors, adding complexity to experiments and presenting notable practical challenges (V. Kumar and Guria, 2013; Magnin and Piau, 1990; Plucinski et al., 1998; Sochi, 2011; Westover, 1966). Various signatures indicate the presence of apparent slip in diverse rheological and flow systems. One such indicator is the dependence of rheological properties on the specific flow geometry (Chen et al., 2009; Maciel et al., 2002; Meeker et al., 2004; Sochi, 2011), along with the dependence of measured quantities on surface characteristics such as roughness (Larson, 1999; Walls et al., 2003).

When apparent slip is present, there is relative motion to the solid surface even when the applied stress is below the yield stress. This reduces the actual yield stress behaviour of the material, introducing complexity in accurately understanding its flow characteristics (Kalyon et al., 1993; Russel and Grant, 2000; Sochi, 2011; Walls et al., 2003). To minimize or eliminate slip artifacts, the typical approach involves increasing the roughness of the solid surface in contact with the sample. This can be achieved through methods such as grinding, sanding, coating, or chemical treatment, introducing irregularities to enhance friction (Barnes, 1995; Meeten, 2004; Song et al., 2003). This agrees with (Abedi et al., 2021) study who confirmed that the implementation of smooth concentric cylinder geometry is another problem. The authors showed that because of wall slip, the values of dynamic yield stress measurements and static yield stress measurements were at least 30% lower than the true values when wall slip was present. The authors reported that utilizing geometries featuring smooth surfaces, as opposed to grooved or serrated ones, does not alleviate wall slip and results in inaccuracies in measurements, especially at low shear rates. Hence, it is important to bear these limitations in mind.

Plastic viscosity (PV). Drilling fluids are typically made up of

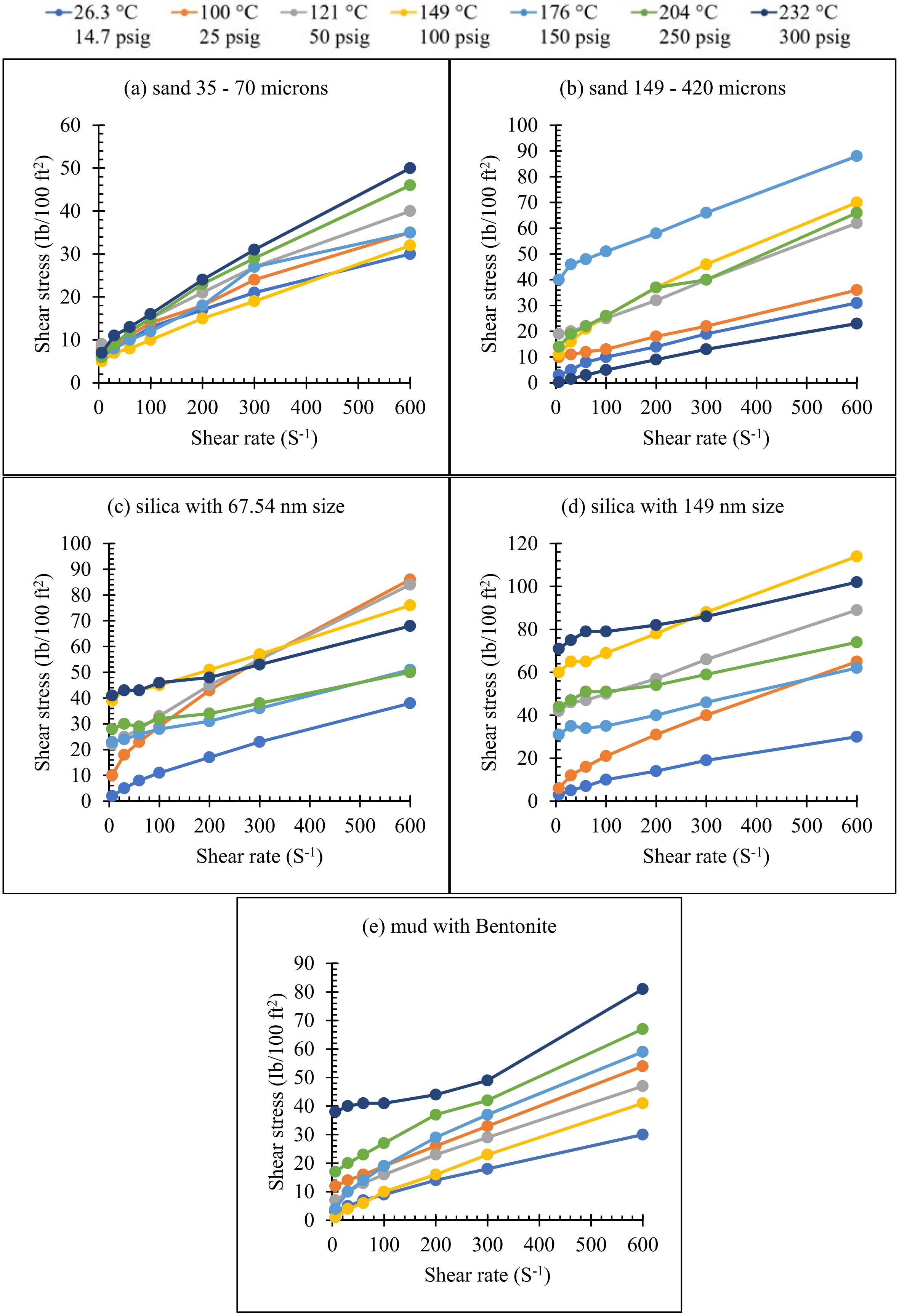


Fig. 4. Rheological curves of drilling fluid at different shear rates.

scattered particles in a continuous phase. Plastic viscosity is caused by Solid-to-solid mechanical friction, which is responsible for the entire flow resistance. Fig. 5 presents the PV of the mud samples after aging. It was observed that PV increased with increasing temperature for all mud samples. Except for sample S5, there was a decrease in PV following the addition of NPs at room temperature. This reduction was because of the repulsive forces between silica nanoparticles and bentonite which prevented coagulation. Coagulation is the process by which particles come together to form larger aggregates or clumps. This is undesirable where particle stability is crucial. Therefore, the repulsive forces keep suspended particles apart and dispersed as single particles hence maintaining stability and resulting in reduced PV. The drilling fluid with the lowest viscosity is always preferred because it increases rate of penetration (ROP), provides better cooling and lubrication functions to borehole equipment, decreases pump pressure needed to facilitate circulation, and also reduces fluid loss to the formation. (Parizad et al., 2018; Salih and Bilgesu, 2017). As temperature increased, higher PV profiles were witnessed. Increase in PV was due to the kinetic activity of the particles in the drilling fluid caused by temperature increase. This leads to increased shear inside the mud system. (Ismail and Paramasivam, 2016) hence resulting in increased PV with increasing temperature. High temperature environments degrade the original texture of the mud by changing the physiochemical structure of the mud. Mud sample S4 displayed the highest PV readings followed by the reference mud as temperature increased above 121 °C. Temperature exerted a high temperature thickening effect were the mud experienced an increase in viscosity (Bland et al., 2006). All mud samples showed the same trend of increasing PV after a temperature of 121 °C. It should be noted that mud PV should not uncontrollably increase as when that happens, flocculation might occur leading to high YP hence resulting in loss of pump pressure, surge, and swap pressure increase, decreased ROP and increased pump pressure costs. A low or excessive YP may lead to sagging of barite which is undesirable too (Li et al., 2015; Salih and Bilgesu, 2017). Mud samples S2 maintain a stable PV profile up to 176 °C and thereafter, a steady increase was observed. This was due to the interaction of negatively charged bentonite and cationic modified sand particles in the mud system, which resulted in the formation of bigger size particles resulting in the formation of larger particle size and low the viscosity (Ismail et al., 2016). Addition of NPs and sand particles led to a more stable viscosity profile at higher elevated conditions indicating both sand and nanoparticle's ability to suppress viscosity reduction hence resulting to similar rheological behaviour at changing temperatures except for S5 sample.

Yield point. Fluid resistance to flow produced by electrochemical attractive forces between the particles in the mud is known as the yield point. Negative, neutral, or positive charge can be found on the surface of scattered particles in drilling fluids. These charges generate electrochemical attractive or repulsive forces under dynamic conditions, causing the YP to rise or fall. (Afolabi et al., 2017; Gbadamosi et al., 2019). Fig. 6 above shows temperature effects on the yield point of the mud samples. YP is the critical value that must be surpassed by a shear stress to initiate fluid flow, and it shows the cutting carrying or suspending capacity of the mud. (C. Martin et al., 2022a,b). Fig. 6 shows that as temperature increased, the effects of temperature on the mud varied non-monotonically. Nanoparticle muds demonstrated increased Yield Point (YP) values above 121 °C compared to the reference mud, except at ambient conditions and at 100 °C, where S1 without nanoparticles exhibits slightly higher YP profiles than S4. Bentonite water-based muds maintain stability up to a temperature of 121 °C and display shear thickening behaviour beyond this temperature. This behaviour leads to gelling and solidification, causing filtration challenges in the borehole, especially at higher temperatures. (J. R. Smith, 2001). Increase in YP is because of the electrostatic attractive forces in the colloidal dispersion. Sample S5 displayed a high YP from 121 °C. Increase in YP is attributed to the higher attractive forces between the positive edge of bentonite and negative surface of silica nanoparticle. The high attractive forces were linked also to nano silica's large surface area which promotes excellent chemical reactivity leading to increase in YP (Gbadamosi et al., 2019; Vipulanandan et al., 2018). S3 sample performed better than other drilling fluid samples except for S5 formulation. This novel additive demonstrated improved cutting carrying abilities up to a temperature 176 °C and thereafter, all NP drilling fluid samples showed similarly the same YP profile apart from S5 formulation. The performance of S3 is attributed to the interaction between negatively charged bentonite and modified sand which yielded larger fragments in the dispersion resulting in reduced viscosity and increased yield point (Ramos-Tejada et al., 2001). Muds containing sand particles and nanoparticles exhibited enhanced Yield Point (YP) profiles as the temperature increased, surpassing the performance of the reference mud. S3 sample was better than S2 and S5 better than S4 respectively. Samples S3 and S5 both had a slightly bigger size than S2 and S4. Complex formulation with a wider range of distribution of particle sizes, such as a reduction in nanoparticle size less than 1000 nm and larger nanoparticles with a particle size distribution of 10–100 nm, is more likely to provide the desired effects. (S. R. Smith et al., 2018). Bigger particles acted as balls in the dispersion, avoiding coagulation and

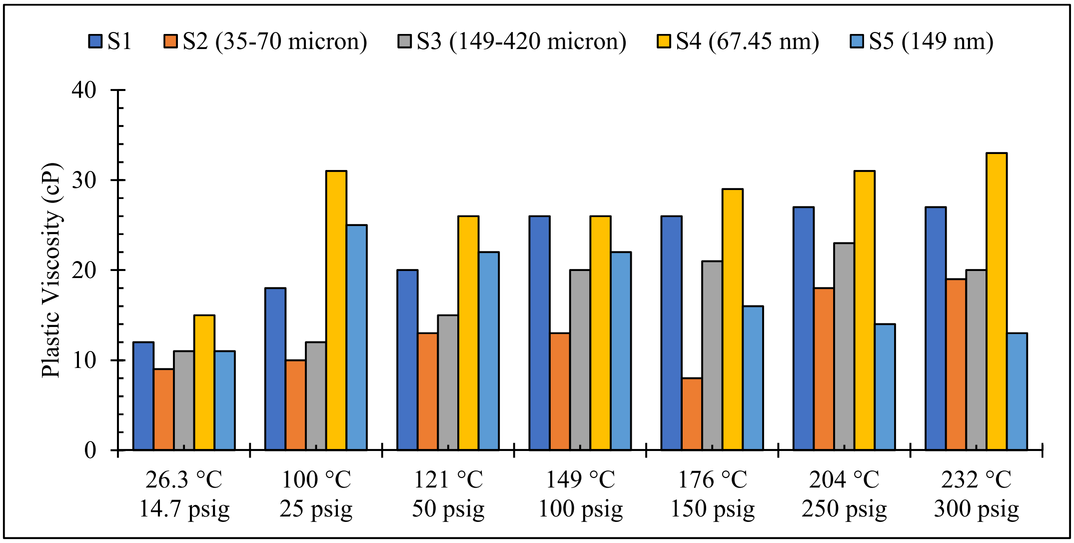


Fig. 5. Temperature effects on the plastic viscosity of mud formulations.

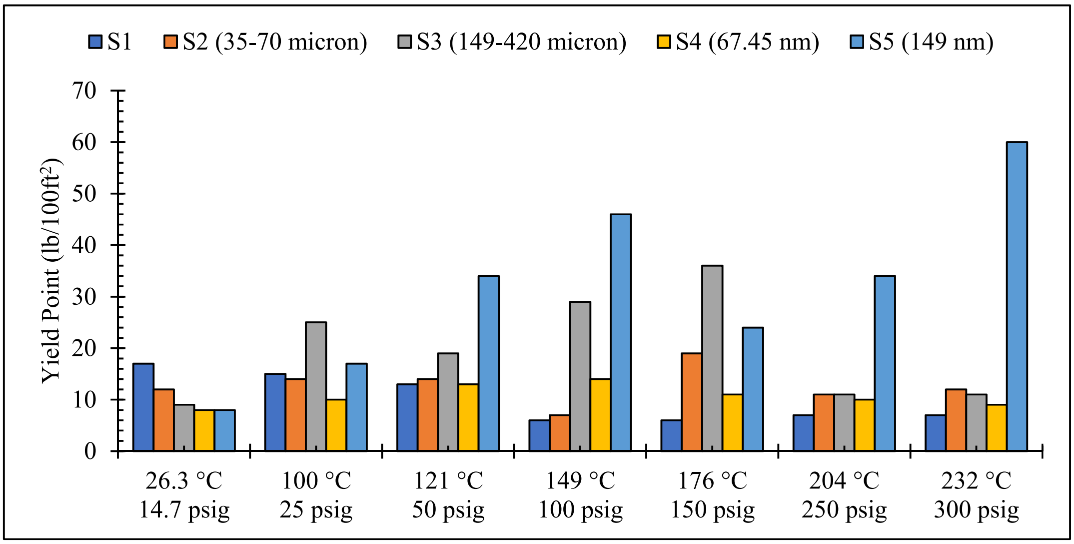


Fig. 6. Temperature effects on the yield point of mud formulations.

resulting in a greater yield point. Nevertheless, the maximum YP within the range is always preferable since it supports efficient cuttings lifting abilities of a drilling fluid, whereas a lower value may induce barite sagging, which is a difficult problem to solve. From a temperature of 121 °C, the reference mud YP started decreasing symbolising a decline in the drilling fluid cutting carrying abilities indicating start of fluid failure. Yield point decrease is related to bentonite breakdown prompted by HPHT conditions. Temperature increases cause bentonite to hydrate and passivate, affecting clay characteristics. Bentonite is a type of clay that undergoes a process called hydration when exposed to water. Absorption of water molecules into the clay structure, causes it to swell and change its properties.

The electrochemical effect due to temperature changes accelerate the ionic activity of the electrolyte and the solubility of any partially soluble salts available in the mud. This alters the balance of repulsive and attractive interaction between particles hence affecting the level of dispersion and flocculation of the mud system (Ibeh, 2010). Therefore, NP and sand particle muds stabilized the yield point at elevated temperatures better than the reference mud with sample S5 exhibiting effective dispersion abilities than S4. This occurred because of the well-dispersed NPs present which resulted in a more uniform distribution of conventional additives in the mud fluid, allowing polymers to experience greater hydration and thereby retaining the base fluid's YP. By dispersing the clay at high temperature, NPs worked as joiner and retained the mud characteristics. When dissolved in water, the polymers uncoiled and formed a straight chain due to repulsion of the same charged groups (Martin et al., 2022b). Moreso, a complex formulation, incorporating a diverse range of particle sizes, including smaller particles under 1000 nm and larger nanoparticles within the 10–100 nm range, is more likely to achieve the desired effects (S. R. Smith et al., 2018).

HPHT Filtration loss. Different additives to include polymers, clay and dispersants are utilised to enhance the filtration properties of the mud. The mud samples' filtration capabilities were investigated and are shown in Fig. 7 below. The resultant pressure is essentially directed outwards or toward the formation at any point in the wellbore. This is attributed to the overbalance that exists throughout the drilling operation to keep the formation from experiencing a kick or influx of uncontrolled formation fluids. The mud is forced to infiltrate the formation structure by this pressure. The filtrate goes further in the formation while the solid part of the mud develops a thin plaster around the wellbore. If this filtrate loss occurs in shale formations, it can promote

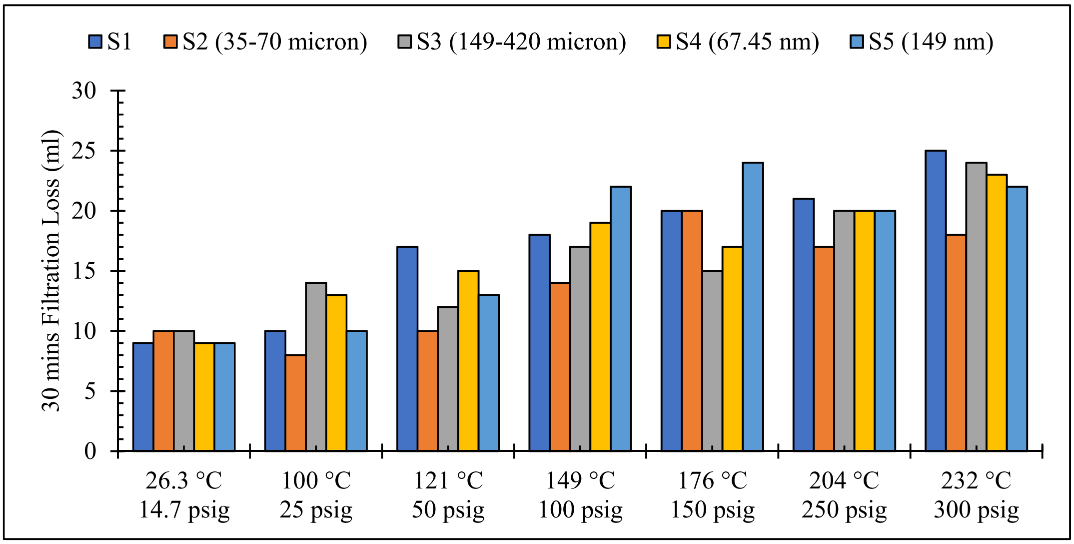


Fig. 7. Temperature effects on the filtration loss of mud formulations.

clay swelling, and if it occurs in the production zone, it can change the pay zone's wettability and relative permeability. All of this adds to the difficulties and deterioration of the shale formation's integrity in the initial stage and, in the later stage affect production from the well (Mahto and Sharma, 2004). Therefore, reducing filtrate loss to the formation is very vital in order to avoid production problems and facilitate smooth drilling operations.

From Fig. 7 below filtrate loss increased as temperature increased for all mud samples. The control mud performed similarly or better than NP muds at LPLT conditions as all drilling fluid lost similarly the same filtrate. This trend changed as temperature increased further with the reference mud registering the highest filtrate loss at 121, 204 and 232 °C.

The rise in filtrate loss is attributable to bentonite WBMs' capacity to preserve stability up to 121 °C and exhibit shear thickening behaviour at elevated temperatures. This will result in borehole gelling and filtration issues (S. R. Smith et al., 2018). Also, in HPHT conditions bentonite tends to flocculate and aggregate which decreases mud rheology and fluid loss control abilities. However, the introduction of silica NPs did not totally fix the problem because filtrate loss increased with the addition of silica NPs. This is because of bentonite particle deflocculation caused by the repulsive electrostatic forces between the negatively charged bentonite surface and negatively charged silica surface interaction leading to failure to form strong linked structures to strengthen the chains between bentonite and NPs (Bourgoyne et al., 1986; Elochukwu et al., 2017; C. Martin et al., 2022a,b). Compared to the control mud and the mud samples with Silica NPs, drilling fluids with sand particles lost the least amount of filtrate overall. Mud sample S2 registered the least filtrate loss. This is partially attributable to the NPs' size, which made it easier to block and seal the nanopore throats of the clay, hence minimising filtrate loss. Additionally, the edge-to-face (positive edge bentonite-negative face bentonite) and face-to-face electrostatic attraction between (modified nano sand and bentonite) enabled the formation of clusters that trapped sand particles between clay particles, creating heterocoagulated formation that traps the fluid within the structure and thus reduces fluid loss. (Daswani and Van Herk, 2014; Kickelbick, 2007). In addition, when two particles with different features, like size, charge or chemical compositions interact, a cluster forms, accompanied by a gel-like structure, which is commonly referred to as heterocoagulation (Kickelbick, 2007). Except for mud sample S2, whose filtrate loss stayed constant at increasing temperatures of 204 °C and 232 °C, the filtrate loss of other mud samples increased. At the same temperatures, the reference mud lost the highest filtrate compared to all other mud samples. S2 sample performed better than sample S3 and this is because the bigger size of S3 failed to plug the pores hence losing more filtrated than the S2 with a smaller size. Other dynamics still need to be investigated in relation to different sizes of sand NPs than those tested in this work.

Mud cake. When filtrate is lost from the wellbore into the formation via the permeable zone, a mud cake forms at the wellbore across the porous zone. The formation can be damaged by excessive filtration loss. When filtration occurs, any successful mud formulation must produce a thin, firm impermeable filter cake to reduce further formation contamination because of filtrate loss and to avoid blocked pipe due to an uneven or overly thick mud cake. (Ismail and Paramasivam, 2016). Fig. 8 presents the filtrate cake thickness created during the filtration test after the mud samples were aged at various temperatures.

Fig. 8 illustrates that the thickness of the filter cake formed is closely related to the fluid loss, if not directly proportional. Higher ageing temperature resulted in higher filtrate loss volume, which led to the formation of a thicker mud cake. The control mud produced a slightly thinner mud cake up to a temperature of 149 °C compared to all other muds apart from sample S2 and thereafter, the mud cake started to increase. The thickness of the filter cake increased with increase in temperature for all mud samples with sample S3 exhibiting a thicker mud cake compered to all other mud samples including the reference mud at temperatures of 204 °C and 232 °C. The problem previously described is made more worse by the thermal degradation of filtrate control additives and viscosifers. This is because, at 149 °C, starch undergoes a process known as hydrolysis and depolymerization of thinners, or irreversible chemical processes, which results in the drilling fluid's full degradation (Chesser and Enright, 1980). Mud formulation S2 formed a thinner mud cake when compared to other drilling fluid formulations which explains why this sample had the least amount of filtrate loss compared to other samples at practically all temperatures. According to the findings shown in Fig. 9, the mud cake permeability of muds with sand particles was lower than that of muds with silica NPs and the control mud. In addition to the above, drilling fluids containing sand particles result in a thinner and non-erodible filter cake. On the other hand, drilling fluids with silica nanoparticles and the reference mud sample lead to the formation of soft filter cakes with higher permeability. In light with these observations, the theoretical idea of the formation of the rigid structure network between bentonite and sand NPs because of electrostatic attraction is supported by these findings. According to this analysis, sand particles were the best option for minimising fluid loss, but a lesser percentage may be selected if a lower

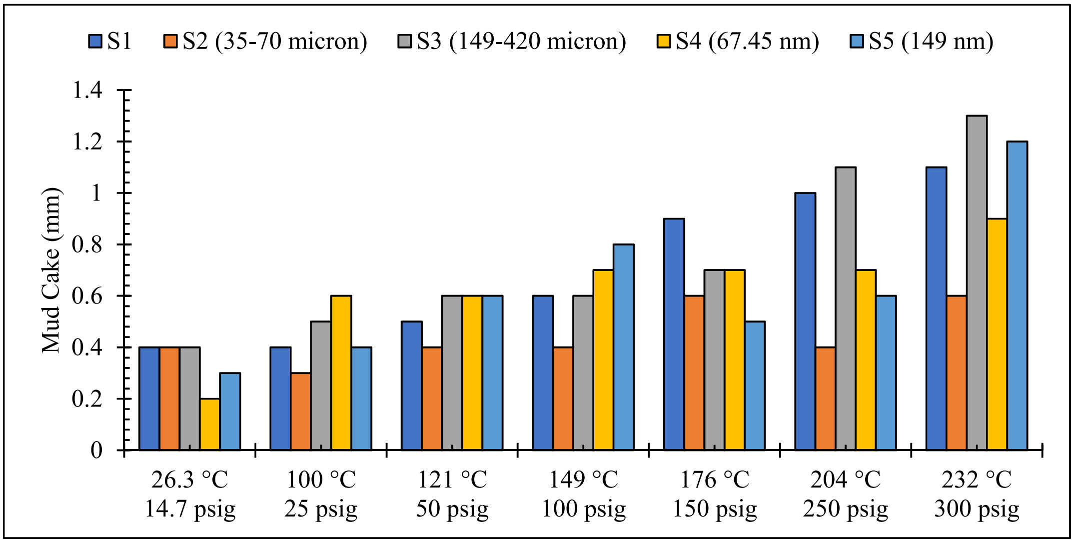
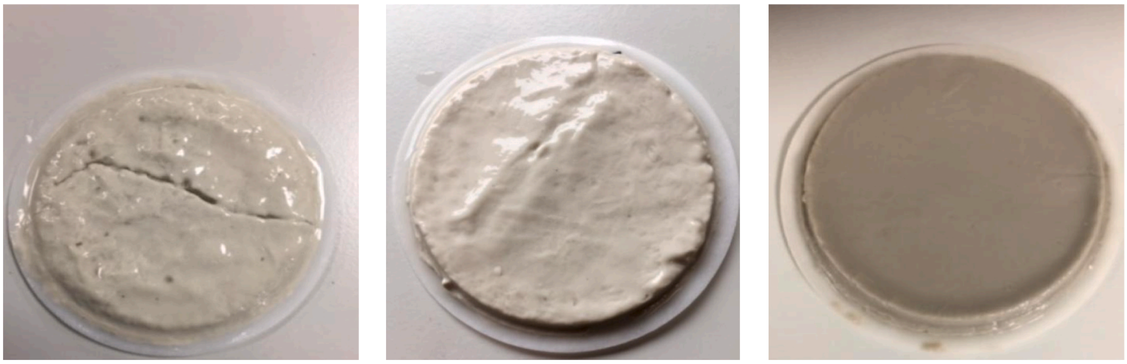


Fig. 8. Temperature effects on the mud cake of mud formulations.



Reference

Silica NPs

Sand

Fig. 9. Mud cakes produced by mud samples containing nano silica and sand under HPHT conditions.

viscosity and yield point are required for WBMs to have a greater drilling efficiency.

Gel strength. The power of attracting forces in drilling fluid when at rest is referred to as gel strength. The ability of a mud system to form and maintain a gel structure when the drilling fluid is static is a vital requirement. A good gel strength is always essential to sustain the high circulation pressure required to resume drilling operations.

It was observed from Fig. 10 above that gel strength fluctuated non-monotonically with temperature changes. Most mud samples displayed similar gel strength as temperature reached up to 121 °C, with the exception of sample S3, whose gel was greater. That was because of the size of the nano sand used. When the temperature rose above 121 °C, the gel strengths of S2, S3, and the control mud remained constant, but this tendency was reversed for samples S4, and S5, which showed higher gel strengths at 149 °C, 176 °C, 204 °C, and 232 °C, respectively. It is possible to conclude that sample S2 maintained a steady gel strength as temperature increased, demonstrating the same gel strength at all temperatures. It should be noted that a very high gel strength is undesirable because it may increase pumpability costs if drilling resumes.

4. Conclusion

The widespread adoption of nanoparticles in drilling fluid systems is evident in the industry, driven by their proven benefits in enhancing stability, rheological properties, and overall drilling efficiency. However, the considerable expense associated with nanoparticles and environmental concerns have underscored the need for more cost-effective and eco-friendly alternatives. The industry is actively pursuing additives that can deliver similar advantages but at a lower cost, while also minimising the environmental footprint of drilling operations. This dual objective reflects a broader industry trend towards sustainability and cost efficiency.

This experimental study investigated the performance of silica nanoparticles and a novel particle that is sand particle grafted with a cationic surfactant to ascertain their performance in a water-based mud. Comparisons were made between silica nanoparticles and sand particles with the bentonite mud as a benchmark. The following conclusions are drawn from this analysis:

1. Addition of a cationic grafted sand particle improved the rheological properties of the drilling fluids by improving the thermal stability and filtration abilities of the mud fluid. Altering the electrostatic forces on the surface of sand particles resulted in an enhancement of both reactivity and dispersion capabilities of sand particles. From our previous work, it was discovered that different dynamics play apart in stabilising colloidal solutions such as zeta potential, repulsive and attractive forces.
2. From the two sizes tested of sand particles, S2 (35–70 micro) performed better than S3 (149–420 μm). The formulation containing sand of size 35–70 μm exhibited better rheological properties because of its increased surface area to volume ratio which resulted to effective interaction and dispersion within the colloidal solution. Therefore, the contact area between CTAB and sand particles of size

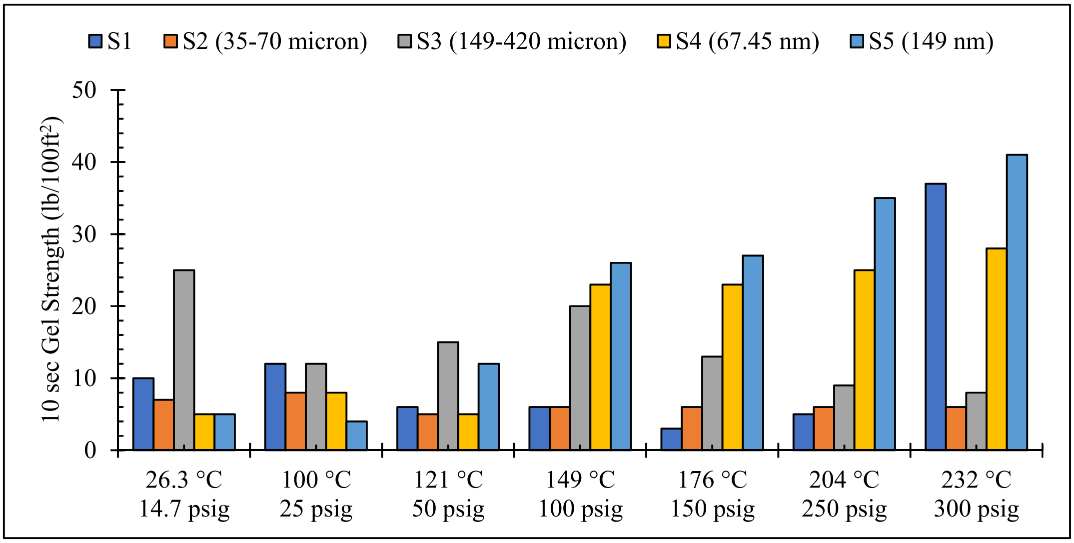


Fig. 10. Temperature effects on the 10 s gel strength of mud formulations.

35–70 μm would be large enough as compared to larger sized sand of 149–420 μm leading to a large surface area for interaction.

3. Sample S2 showed stable thermal stability at all temperatures by exhibiting similarly the same rheological readings with change in temperature.
4. The optimal concentration of NPs and sand particles was maintained at 0.5 wt%, as it demonstrated the most significant improvement in various rheological properties, particularly observed in S2. The authors had previously conducted tests to determine the optimal concentration of silica NPs, and 0.5 wt% was identified as the most suitable concentration, leading to its adoption in the current study.
5. Even though sand particles demonstrated better performance than silica nanoparticles in drilling fluids, it's noteworthy that silica nanoparticles outperformed the control bentonite mud by enhancing rheological properties under high-pressure, high-temperature (HPHT) conditions.

CRediT authorship contribution statement

C. Martin: Conceptualization, Data curation, Formal analysis, Investigation, Methodology, Project administration, Writing – original draft, Writing – review & editing. **A. Nourian:** Project administration, Supervision, Formal analysis. **M. Babaie:** Formal analysis, Project administration, Supervision, Validation. **G.G. Nasr:** Project administration, Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

Nomenclature

WBMs	Water based muds
OBMs	Oil based muds
ATM	Atmospheric pressure
Pac	Polyanionic-Cellulose
HPHT	Hight pressure/High temperature
LPLT	Low pressure/Low temperature
SiO_2	Silica dioxide
SNPs	Silica nanoparticles
NPs	Nanoparticles
API	American Petroleum Institute
YP	Yield point (100 Ib/ft^2)
PV	Plastic viscosity (cP)
BHR	Before hot rolling
AHR	After hot rolling
R	Reference bentonite mud

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