Petroleum Science 18 (2021) 1709–1728

Contents lists available at ScienceDirect

Petroleum Science

journal homepage: www.keaipublishing.com/en/journals/petroleum-science

Original Paper

Performance of water-based drilling fluids for deepwater and hydrate reservoirs: Designing and modelling studies

Moumita Maiti [a], Ajoy Kumar Bhaumik [b], Ajay Mandal [a, *]

[a] *Department of Petroleum Engineering, Indian Institute of Technology (Indian School of Mines), Dhanbad, India*
[b] *Department of Applied Geology, Indian Institute of Technology (Indian School of Mines), Dhanbad, India*

ARTICLE INFO

Article history:
Received 17 July 2020
Accepted 30 April 2021
Available online 8 September 2021

Edited by Yan-Hua Sun

Keywords:
Deepwater drilling fluid
Filtrate loss
Gas hydrate
Rheology
Nanoparticle-based drilling fluid

ABSTRACT

In deepwater drilling, the properties of water-based drilling fluids change remarkably due to low temperature and high pressure, which have a significant effect on lost circulation, wellbore instability and the window between pore pressure and fracturing pressure. The present work investigates the influence of low temperature and high pressure on polymer and nanoparticle (boron nitride (BN)) based drilling fluids with an aim to improve their rheological properties and fluid loss control. The amplitude and frequency sweep tests were conducted to understand the viscoelastic nature of the samples. The amplitude sweep tests confirmed the structural stability of the designed fluid within the studied sweep frequency. The study reveals that storage modulus (G') and loss modulus (G'') of the samples are enhanced with increasing concentration of BN nanoparticles. Their viscoelastic range also increases due to the intermolecular interaction within the structure of the fluid in the presence of the nanoparticles. Within the linear viscoelastic range (LVER), all the samples show the dominance of elastic modulus than viscous modulus which delineates the solid-like behaviour. The results of rheological tests of drilling fluid containing BN nanoparticles indicate a significant reduction in plastic viscosity (PV), yield point (YP) and apparent viscosity (AV). The rheological studies conducted at different temperatures (from 10 °C to −5 °C) and pressures (from 7.8 MPa to11 MPa) reveal the minimum effect of pressure and temperature on the rheology of samples, which are desirable for their applications in hydrate and deepwater drilling. The filtration loss experiments conducted at 30 °C and 0.69 MPa show a large reduction in fluid loss volume (60.6%) and filter cake thickness (90%) for the sample with 0.4 wt% BN nanoparticles compared to that of the sample without nanoparticles. The filter cake permeability is also in the favourable range with 0.008 mD which shows a 94% reduction compared to the sample without nanoparticles. A regression model was developed to mathematically describe the experimental results, which demonstrates a good fitting with the statistical data of fluid loss volume, thickness and permeability of the filter cake.

1. Introduction

Increasing demand for petroleum and petroleum products worldwide has led to the exploration and production of oil from complicated reservoirs, and deep offshore is one of those. Formation of gas hydrates is also a severe problem associated with the production from deepwater reservoirs at low temperature and high pressure. Suitable formulation of drilling fluid is one of the most important parameters for a successful drilling operation for such type of reservoirs. The main functions of the drilling fluids are to maintain wellbore stability, carry cuttings from the bottom of the hole to the surface, cool and lubricate drill bits, reduce formation damage, control subsurface pressure, allow adequate formation evaluation, seal permeable formations, prevent well control issues, convey hydraulic power and to gain data from the formation (Chu and Lin, 2019; Jensen et al., 2004). The properties of a drilling fluid include physical, chemical and rheological characteristics. While investigating these properties, it is very important to formulate the drilling fluid which will be environmentally friendly and low cost. In the drilling industry, water and clay formulates a simplest type of drilling fluid. Bentonite is a popularly used clay in the drilling industry because it can easily get hydrated by water and

* Corresponding author.
E-mail address: ajay@iitism.ac.in (A. Mandal).

https://doi.org/10.1016/j.petsci.2021.09.001
1995-8226/

also act as a viscosifier. In addition, it has the capability to enhance hole cleaning ability when added to the drilling fluid (Wang, 2006).

As the development of deepwater (offshore) drilling is rapidly increasing, the complexity associated with this type of drilling such as wellbore instability, lost circulation, hole cleaning capacity becomes a major issue (Zhao et al., 2019). The temperature of deepwater reservoirs varies widely and hence, the drilling is highly challenging as the rheological properties of drilling fluids are significantly affected by temperature (Hu et al., 2011). One of these challenges is that, used drilling fluids should have suitable rheological properties at low-temperature and high-pressure conditions. Temperature and pressure vary in the deepwater drilling operation which largely affects the rheological properties of the drilling fluid and therefore it becomes very much difficult to control the yield point, plastic viscosity and gel strength of the drilling fluid which leads to lost circulation, high equivalent circulating density (ECD) (Cameron and Baroid, 2005; Alcázar-Vara and Cortés-Monroy, 2018). With decreasing temperature, the yield point and viscosity of the drilling fluid increase which leads to downhole lost circulation during drilling (Xie et al., 2018). In this study, the addition of different suitable additives to drilling fluids helps in reducing the effect of temperature on rheological properties of drilling fluids. So, with decreasing temperature in deepwater drilling operation, the drilling fluid shows almost constant rheological properties which is desirable for deepwater drilling.

In the deepwater offshore environment, the temperature of the formation could be 4 °C or even less (Zhao et al., 2015b). Gas hydrate is one of the most hazardous problem in deepwater drilling because it can cause severe threats to the safe and effective drilling. In deepwater environment, the extreme conditions of temperature and pressure mean that hydrates may form during the drilling process if the fluids containing water come into contact with the reservoir fluids. Formation of solid hydrates can plug up subsea risers, choke and kill lines, and blowout preventers (BOPs) (Liang et al., 2014). Conditions during well shut-in are particularly favourable for hydrate formation if high pressures are combined with falling temperatures and there is sufficient time for equilibrium to be reached. Natural gas hydrate is an ice-like crystalline solid structure, where water molecules form a cage-like structure within which gas molecules are trapped at low-temperature and high-pressure conditions (Sloan and Koh, 2000). These are considered as a huge source of energy. Gas hydrates are generally available under low-temperature (<26 °C) and high-pressure (>3.5 MPa at 3 °C) conditions (Sloan and Koh, 2000). In deepwater offshore conditions, drilling operation experiences the lowest temperature of around 2–4 °C. In Gulf of Mexico and South China sea (at a water depth of 3000 m) where the temperature is around 2–4 °C and the pressure is about 30 MPa, the drilling operations often face hydrate formation (Zhao et al., 2015a). Cold seawater can easily drop the temperature of the sample which in result increases the viscosity of the sample and affects surge pressure and equivalent circulating densities (ECD) (Young et al., 2012). Therefore, rheological properties of drilling fluids at low temperature are important to know.

There are different types of drilling fluids such as water based, oil based, synthetic based and pneumatic drilling fluids (Katende et al., 2019). Choice of the base of the drilling fluid is vital as it affects the behaviour of the drilling fluid during drilling.

Oil based drilling fluid is considered best mud system for better lubricating properties. Oil based drilling fluids have a very significant effect on filtration properties which makes them very useful in numerous drilling fluid operation (Herzhaft et al., 2002; Wegner et al., 2006). This system affords better hole cleaning capacity, wellbore stability, filter cake quality, less torque and drag force (Friedheim and Patel, 1999). But there are some drawbacks like non-environmentally friendly, high cost, safety issues (Karen et al., 2014). Vapours and mists extracted from oil-based drilling fluids are hazardous to personnel of uncontrolled exposure which includes negative impact on central nervous system causing dizziness, tiredness, headaches and it can even cause pneumonia, bronchial asma and possibly cancer (James et al., 2000).

Synthetic based drilling fluids (SBDFs) are one of the preferable choices in deepwater drilling due to their ability to achieve high penetration rate and can maintain required wellbore stability. SBDFs are environmentally friendly as the additives used in this type of drilling fluids are low in toxicity (Li et al., 2016a, b). Synthetic based drilling fluids have a great ability to form thin filter cake. This implies that the synthetic based drilling fluids have the capability of holding the fluid much longer in the reservoir without damaging the formation (Adesina et al., 2017). However, lost circulation is one of the drawbacks for synthetic based drilling fluids which is caused by their adverse elevation of viscosity and increase in equivalent circulation density (ECD) and hydrolysis (van Oort et al., 2004). Synthetic based drilling fluids are comparatively more toxic and more cost effective than nano-water based drilling fluids.

Some advantages of pneumatic drilling fluids include excellent rate of penetration in dry competent formations, low cost drilling fluid, minimum damage to water-sensitive pay zones, long life of drill bit, little or no fluid disposal problem (Malloy et al., 2007). However, some disadvantages are also reported in literature, for instance, this drilling fluid does not have the ability to tolerate water, it can cause downhole fire when hydrocarbons are encountered, can cause excessive erosion near the top of the hole where expansions results in high annular velocity and the disposal of waste gas can also be a hazardous situation (Mahasneh, 2013; Cooper et al., 1997). On the other hand, nano-water-based drilling fluids are widely used in the oil and gas industry due to their superior rheological properties and low filtrate volume which helps in stabilizing the wellbore. They are not toxic for environment and are cost effective. Thus, water-based drilling fluids with nanoparticles are further developed to achieve superior performance and maintaining their less harmful environmental credentials. Therefore, in spite of slower drilling process, water-based drilling fluids are very common. Mechanical friction while drilling with water based drilling fluids is significantly higher than that of oil based drilling fluids (Alvi et al., 2018). To minimize the drag force, boron nitride (BN) nanoparticles are being used which behaves as a lubricant agent. It is to be believed that the use of nanoparticles in drilling fluids is the first potential large scale application of nanoparticles in the oil and gas industry (Cheraghian, 2017). Nanoparticles are fundamentally made to have 1–100 nm in diameter. Nanoparticles are very applicable in formulating suitable drilling fluids because of their unique physico-chemical properties. This is due to their very small size as well as their remarkable high surface to volume ratio (Zakaria et al., 2012). Due to their significantly unique properties, nanoparticles have the ability to enhance the function of additives used in drilling fluids. Nanoparticles also have the capability to maintain their characteristics even under different environmental conditions (Vryzas and Kelessidis, 2017). Nanoparticles used in this study are hexagonal boron nitride (h-BN) nanoparticles which possess very similar structures to that of carbon materials. In hexagonal form of BN, alternate boron and nitrogen atoms form an interlocking hexagonal structure. Each layers of the BN nanoparticles are held together by weak van der Waal forces (Tran et al., 2016). However, it is very difficult to choose proper additives to formulate proper drilling fluids (Razi et al., 2013). BN is a high thermal conductive nanoparticle. Guar gum is a natural, carbohydrate, non-ionic polymer which has the capability to enhance the viscosity of water-based drilling fluid and has good thermal stability (Hasan et al., 2018).

Control of filtrate loss is a vital property of drilling fluid because it influences the drilling operation in various ways such as hindrance of variance sticking, avoid formation damage and maintain wellbore stability (Razi et al., 2013). Overall filtrate loss has a significant effect on the performance of the drilling fluid, well production and drilling cost. Drilling fluid creates a filter cake which forms a bridge of formation face under an overbalance condition (Yao et al., 2014). Modelling the rheological and filtrate loss behaviour of nano-enhanced drilling fluids are significant when designing and planning for economical drilling operations which involves nanoparticles. The properties of the improved drilling fluids attained during drilling condition were investigated at various downhole conditions. The known characteristics of drilling fluids such as rheology, wellbore strengthening, fluid loss control and cuttings carrying capacity can be altered with the addition of nanoparticles (Vryzas and Kelessidis, 2017). Gerogiorgis and Reilly (2017) reported an encouraging endeavour on modified rheology and fluid loss control of nano-enhanced drilling fluid. The model used in the characterisation of bentonite based drilling fluid only permits a generalised explanation of mud behaviour (Gerogiorgis and Reilly, 2017). In such cases, e.g., viscosity and shear stress described by rheological model is only stated by data driven correlation of shear rate. This does not have the ability to customize the model to express the above mentioned shear stress and viscosity as a function of multiple independent variables such as the influence of nanoparticles to the overall model. Similar condition is applicable in the case of fluid loss behaviour of nano-enhanced drilling fluid. API fluid loss model is a function of time and parametrised method has been selected to better describe the influence of nanoparticle-enhanced drilling fluid on fluid loss control.

This article discusses the behavioural investigation of drilling fluids with varying composition including nanoparticles through some rheological properties like plastic viscosity, apparent viscosity and viscoelastic properties. The filtrate loss is examined before and after the addition of nanoparticles. Experimental and statistical analysis of the fluid loss volume, and the thickness and permeability of the filter cake have been conducted. The API filtration model is a function of time. The approach of different parameters is discussed when defining the nano-enhanced drilling fluid (Afolabi et al., 2018). The contribution of bentonite, guar gum and BN nanoparticles to a reduction of fluid loss is apprehended in the regression model. Statistical tools regarding regression modelling such as coefficient of correlation (R^2), Fischer's ratio (*F* value) and probability value (*P* value) are the main indication of approval of this model.

2. Materials, experimental equipment and methods

2.1. Materials used

In the laboratory, the formulation of some drilling fluids was developed for deepwater offshore drilling. The bentonite used in this experiment was purchased from Loba Chemie Pvt. Ltd. and added to increase the viscosity. Fig. 1 exhibits the XRD diffraction of bentonite and it confirms that bentonite used in this drilling fluid is mainly contains montmorillonite mineral with kaolinite in some portion as clay minerals. Montmorillonite is the mineral that contains compounds $Al_2O_34Si{\cdot}H_2O$. Other minerals contained in the bentonite is Mg and Ca occasionally. Sodium chlorite (NaCl) (supplied by Finer Chemicals Limited., Ahmedabad) was used to prepare simulated seawater (Kumar et al., 2020). Calcium carbonate ($CaCO_3$) and boron nitride (BN) nanoparticles were supplied from Sisco Research Laboratories Pvt. Ltd. (where $CaCO_3$ was added as a weighting agent as well it helps to form a filter cake over porous formation and inhibit migration of particles into the reservoir and BN nanoparticles were added to decrease the fluid loss volume. Particle size of $CaCO_3$ is ≤ 50 μm. Guar gum (used as a viscosifier) and polyvinyl pyrrolidone K-90 (PVP K-90) (used as a hydrate inhibitors) were obtained from Sigma-Aldrich Chemie GmbH and Central Drug House (P) Ltd. respectively. Molecular weight of PVP K-90 is 40000.

2.1.1. Description of BN nanoparticles

Nanoparticles used in this study is commercially available boron nitride (BN) nanoparticles. The BN nanoparticles have a tendency of agglomeration. It is hexagonal in morphology with a particles size of 70 nm and molecular weight of 24.82. Powder appearance of BN nanoparticles is shown in Fig. 2.

2.1.2. Fluid loss control agents (FLCA)

Constant or excessive fluid loss is a serious problem in the drilling industry due to their effects on formation instability and rheology of the used drilling samples. Furthermore tolerable amount of fluid loss control is beneficial to control the possibility of damaging and sticking (Li et al., 2016a, b). The FLCA for water based drilling fluid is mainly based on their ability to control both the fluid loss volume and enhancement of rheological properties of the drilling fluid. After the comprehensive laboratory evaluation, two FLCAs were selected. Here, guar gum and BN nanoparticles act as a FLCA. Nanoparticles have the ability to enhance the rheological properties of the drilling fluid using various mechanisms which typically depend on the continuous phase of drilling fluids and characteristics of the nanoparticles. Nanoparticles helps plaster in between the macro-sized particles and seal the permeable formation which effectively reduces fluid loss (Paiaman and Al-Anazi, 2009). Addition of guar gum solution to nanoparticle-enhanced drilling fluid also increases the viscosity of the drilling fluid. The interaction between water molecules and the galactose side chain of the guar molecule is responsible for this enhancing result. Interaction of intermolecular chain is enhanced with increasing guar gum concentration (Mudgil et al., 2014). High viscosity of guar gum solution with nanoparticles is because of the interlink bond formed between them. Thus, it helps in reducing fluid loss. On the other hand, pure bentonite-based drilling fluid can lead to serious problems such as bridging the hole, unable to carry cuttings, reduced penetration rate, stuck pipe, blow out or even borehole enlargement. Due to macro-sized particles of bentonite clay and absence of any nano-sized particles, commonly used bentonite drilling fluid does not help in reducing fluid loss volume or enhancing rheological properties of the drilling fluid. Thus, commonly used bentonite drilling fluid is not considered as drilling fluid in this study. Whereas, bentonite clay is added to the nanoparticle-based drilling fluid as a viscosifier and it also helps in reducing filtrate loss by forming a network structure with BN nanoparticles and guar gum to create a less porous and less impermeable filter cake.

2.2. Experimental instruments

A Hamilton beach mixer was used to mix up all the additives in the drilling fluid. Deadweight hydraulic OFITE filter press (Fann Instrument Company, Houston, Texas) was used to measure the filtrate loss of the drilling fluid. Rheological parameters at high pressure (7.8, 9, and 11 MPa) and low temperature (10, 5, 0, −3, and −5 °C) were evaluated with an Anton Paar Rheometer (MCR 102). Every experiment was repeated twice to check if all the results are showing similar values and their reproducibility was found in considerable range with standards deviation ±0.002.

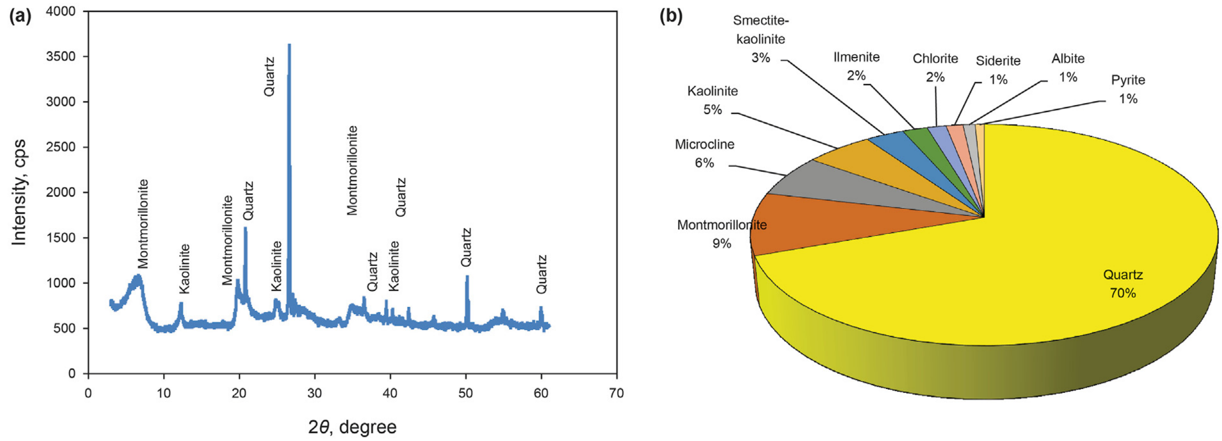

Fig. 1. XRD diffraction analysis of bentonite.

Fig. 2. Powder appearance of BN nanoparticles.

2.3. Experimental procedure

2.3.1. Preparation of conventional drilling fluid

For the formulation of conventional drilling fluid, 4.0 wt% bentonite was added to 400 mL distilled water and then mixed properly. After that, 3.5 wt% of sodium chloride (NaCl) and 6.0 wt% of calcium Carbonate ($CaCO_3$) were gradually added and mixed again properly.

2.3.2. Preparation of nanoparticle-based drilling fluid

2.3.2.1. Preparation of base drilling fluid. Some researchers (Benyounes et al., 2010) reported that with approximately 3.0–4.0 wt% concentration of bentonite, the behaviour of non-Newtonian suspension became more visible. The preparation of the base fluid started with the mixture of bentonite (4.0–5.0 wt%) with distilled water. The additives of these drilling fluids were then combined one by one as mentioned below

NaCl (3.5 wt%)
$CaCO_3$ (6.0 wt%)
PVP K-90 (0.7 wt%)

Before the addition of each additives to the fluid, the mixture was blended for at least 15–20 min with the Hamilton beach mixer to confirm the complete dispersion of all the additives.

Bentonite is generally used to increase the viscosity of the drilling fluid and its functions include lubrication, cooling of the cutting tools and removing of cuttings (Ahmad et al., 2017). $CaCO_3$ was added as a weighting agent as well as it helps to form a filter cake over porous formation and inhibit migration of particles into the reservoir (Iqbal et al., 2019). PVP K-90 was used as a hydrate inhibitor (Liu et al., 2016b). NaCl was used to increase the density of the fluid and reduce the freezing point of the water based drilling fluid (Strømø and Belayneh, 2017). Guar gum is a wildly used polymer which does not have any bad effect on environment. It can be used as a viscosifier in drilling fluids and reduces fluid loss (Razi et al., 2013).

2.3.2.2. Preparation of nanofluid. For the first three samples, guar gum was added to the distilled water to make 0.3 wt% concentration and then mixed it properly. Then, 0.1, 0.2, 0.3, 0.4 and 0.6 wt% of BN nanoparticles were added sequentially to the prepared fluid to formulate nanoparticle-based drilling fluid. After the preparation of the nanofluid, it was ultrasonicated for another 1 h to enhance the stability of the nanofluid and the dispersion of the nanoparticle. Finally, the nanofluid was mixed with base drilling fluid by a Hamilton beach mixer to obtain the nanoparticle-based drilling fluid. Table 1 shows all the drilling fluids with varying concentration of several additives. Here, guar gum and BN nanoparticles were used as a fluid loss controlling agent (FLCA).

2.3.3. Comparison between conventional drilling fluid and nanoparticle-based drilling fluid

It has been portrayed that the nanoparticle-based drilling fluid is more effective and suitable for the drilling industry than the conventional drilling fluid (Ali and Ullah, 2017). Nanoparticles have high reactive surface area which helps them enhance rheological properties and they are even used as a very good fluid loss controller. Conventional drilling fluids show drastic changes in rheology as temperature and pressure changes. This happens due to the effect of temperature and pressure on the viscosity of the drilling fluid. Conventional drilling fluids are unable to resist pressure differential. This behaviour of the conventional drilling fluid leads to some technical problems while drilling in deepwater condition because in these environments, drastic changes in temperature and pressure happens. Some common problems encountered during drilling with the conventional systems are increased viscosity and gel strength which leads to an increased lost circulation with enhanced ECD and reduction in penetration rate (Young et al., 2012). Thickness of the filter cake is also very thick for these types of drilling fluids compared to the nanoparticle-based drilling fluid. The conventional drilling fluid has no capability to control fluid loss volume which can damage the formation. On the other hand, the nanoparticle-based drilling fluid was developed to prevent the issues of conventional drilling fluids. Low temperature and high pressure has a very little effect on the rheology of these drilling

Table 1
Drilling fluids with varying concentration of additives.

Drilling fluid type	Fluid number	Distilled water, mL	Bentonite, wt%	NaCl, wt%	$CaCO_3$, wt%	PVP K-90, wt%	Guar gum, wt%	BN nanoparticle, wt%
Conventional drilling fluid	S0	400	4.0	3.5	6.0	0	0	0
Drilling fluid without nanoparticles	S1	600	4.0	3.5	6.0	0.7	0.3	0
Nanoparticle-based drilling fluid	S2	600	4.0	3.5	6.0	0.7	0.3	0.1
	S3	600	5.0	3.5	6.0	0.7	0.3	0.1
	S4	600	4.0	3.5	6.0	0.7	0.4	0.1
	S5	600	4.0	3.5	6.0	0.7	0.4	0.2
	S6	600	4.0	3.5	6.0	0.7	0.4	0.3
	S7	600	4.0	3.5	6.0	0.7	0.4	0.4
	S8	600	4.0	3.5	6.0	0.7	0.4	0.6

fluids like viscosity and the gel strength does not vary much with decreasing temperature or increasing pressure. And the thickness of the filter cake is also very low which is suitable because thick filter cake will reduce the well diameter, so when drill string is rotating or pulling, it will generate excessive torque and drag force. The nanoparticle-based drilling fluid is able to control fluid loss volume, thus able to control formation damage (Ali and Ullah, 2017).

2.3.4. Rheological and filtration testing

Rheological parameters at high pressure and low temperature were evaluated using a rheometer (Anton Paar MCR 102). After opening the rheocompass software, a measuring bob was attached by gently pushing the coupling up. For each rheological result, the drilling fluid was poured into the cup up to the level marked and then from the control panel, temperature and pressure was fixed. Thereafter, the results were used to calculate plastic viscosity (PV), yield point (YP), and apparent viscosity (AV). Deadweight hydraulic OFITE filter press was used to measure the filtrate loss of the fluid. As specified in the American Petroleum Institute, at first, samples were poured into the cell and then a definite pressure (0.69 MPa) was applied to the cell so that filtration will start taking place. After that, the filtrate was collected by a graduated cylinder for 30 min to measure the filtrate loss of the sample. Low temperature filtration test was conducted by using API LPLT filter press and for high pressure filtration test, HPHT filter press apparatus was used.

2.3.5. Viscoelastic studies of drilling fluid

To determine viscoelastic properties of simulated drilling fluids, oscillatory amplitude and frequency sweep tests were carries out. The viscoelastic properties were examined using the Anton Paar MCR 102 rheometer with cup and bob geometry. 19 mL of drilling fluid was poured into the cup and the shear rate was evaluated through an advanced rotation of the bob which determined the torque require for the evaluation of shear stress. A shear rate of 1000 s^{-1} was applied to the sample before starting the process for uniform dispersion of all the additives added. Then, it was kept in static mode for 1 min before starting the shearing process. The amplitude sweep test was carried out to estimate the linear viscoelastic range (LVER) at a fixed frequency value of 6.28 rad/s and 30 °C. Chosen strain value was 6.28 rad/s, small enough because larger strain value can destroy the structure before measuring the sample's response. Then, frequency sweep was conducted with varying frequency range (100–0.001 rad/s) with constant shear strain value (0.6%). The equilibrium time for all the sample was 3 min.

2.3.6. Particle size analysis of BN nanoparticles

The particle size distribution of BN nanoparticles was measured using a Litesizer 500 particle analyzer manufactured by Anton Paar.

2.3.7. FE-SEM procedure for BN nanoparticles and filter cake morphology

Field emission scanning electron microscopy images of BN nanoparticles were taken using the ZEISS microscope. Filter cakes produced from the filtration process were air dried for 48 h. Then, the morphology of samples was investigated by FE-SEM analysis using the ZEISS microscope. Various magnification has been used while analysing the filter cake morphology.

2.3.8. Zeta potential measurement

Zeta potential is defined as the potential difference between the dispersion medium and the immobile layer of fluid attached to the dispersed particle. Surface charge that appears at the interface between solid and liquid pair when the two are brought into direct contact are responsible for zeta potential (Venditti, 2014). If samples show zeta potential value $\pm$30 mV, then they will have the tendency to agglomerate and flocculate after some time. Whereas, zeta potential value more positive than +30 mV or more negative than −30 mV will have better ability to stay stable for longer time. Zeta potential of the sample was measured using the Anton Paar Litesizer 500. Due to the non-apparent drilling fluid solution, the zeta potential of the sample was measured with diluted solution with a ratio of 1:20.

2.3.9. Measurement of filter cake permeability

The permeability of the filter cake was measured using the methodology of Yao et al. (2014). It is mainly based on the liquid flow through the formed filter cake which is called as Darcy's law. The permeability of the filter cake can be determined by the following equation:

$$q = k_c \frac{\Delta P_c}{\mu L_c} \tag{1}$$

where k_c is the filter cake permeability, m^2; q is the filtrate rate, $m^3/m^2/s$; L_c is the thickness of the filter cake, m; μ is the viscosity of the filtrate, Pa·s, ΔP_c is the pressure drop across the filter cake, Pa.

In Eq. (1), the filtrate rate (q) can be calculated by the slope of the straight-line region of the filtrate volume against time curve, divided by the total filtrate area. Cake thickness, L_c can be measured from the formed filter cake. Viscosity of the filtrate, μ is considered as 1 Pa·s pressure drop ΔP_c is also known. So, with all the known factor such as q, ΔP_c, L_c and μ, the permeability of the filter cake k_c can be obtained from Eq. (1).

2.3.10. Statistical design of experiment

To investigate an interaction and quadratic effect between nanoparticles, guar gum and bentonite clay, a statistical model was created by using 2^2 (2 factors, 2 level) central composite design. To achieve the statistical analysis of the experimental data, MINITAB® 17 (PA, USA) statistical software was used. Using different concentrations of BN nanoparticles in drilling fluids, measurements of fluid loss volume, and the permeability and thickness of the filter cake (response variables) were done. Preparation of the sample is mentioned above. After preliminary experiments, varying concentrations of different additives were selected. The response variables were fitted by a second-order polynomial in Eq. (2):

$$Y = \beta_o + \beta_{ij}X_iX_j + \sum_{i=1}^{2}\beta_iX_i + \sum_{i=1}^{2}\beta_{ii}X_i^2 \tag{2}$$

where Y is the predicted response; β_o is the intercept coefficient; β_i is the linear coefficient; β_{ii} is the squared coefficient; β_{ij} is the interaction coefficient; X_iX_j is the interaction terms; X_i^2 is the quadratic terms.

3. Results and discussion

3.1. Morphology of BN nanoparticles

The morphology of the obtained BN nanoparticles after calcination was assessed by scanning electron microscopy (SEM). Fig. 2 shows the images of BN nanopowder in a dry form. It represents the tendency of the nanoparticles to form agglomeration. It also exhibits nano-plates which describe its only one nano-sized dimensions. The images prove the agglomerates visible in SEM image (i.e. Fig. 3b) are most probably soft agglomerates that undergo disintegration during suspension preparation.

3.2. Agglomeration of BN nanoparticles in both distilled water and polymer solution

The effect of concentration on agglomeration of BN nanoparticles in the presence of distilled water and polymer were investigated by particle size distribution measurements at 30 °C and mentioned in Table 2. Lower temperature has a negligible effect on agglomeration of BN nanoparticles. In the case of dispersed solution of BN nanoparticles in distilled water, as the concentration of nanoparticles increases from 0.3 wt% to 0.4 wt%, the increase in the size of dispersed nanoparticles is marginal but increases abruptly at 0.5 wt% and 0.6 wt%. On the other hand, agglomeration of BN nanoparticles in the polymeric solution was also observed and showed similar results as in distilled water. No significant increase in size was observed in agglomeration from S2 to S6 samples. But the size increases significantly in S7 and S8 samples. From the results (Table 2), it was observed that BN nanoparticles create large agglomerates in the polymer matrix. As the concentration of nanoparticles increases, the size of agglomerates also increases and it becomes dominant which reduces the effective volume fraction of nanoparticles in the polymer solution and ultimately weakens the properties of the sample. Thus, it can be concluded that 0.4 wt% concentration of BN nanoparticles is more suitable to enhance the rheological properties of the drilling fluid.

3.3. Rheological model

For better understanding of the behaviour of drilling fluids and their cuttings carrying capacity, the relationship between shear rate and shear stress is one of the most important factors to know. Shear stress values of different drilling fluids were evaluated using rheological data and are shown in Fig. 4a. It can be seen that with the addition of BN nanoparticles to S1 sample, there is a significant reduction in shear stress (i.e, S2 sample). However, further addition of additives like bentonite and guar gum to the drilling fluid sample leads to a significant increase in shear stress compared to S1 sample. And most significantly, further increasing concentration of nanoparticles produces an increasing trend of shear stress. As shown in Fig. 4a, the flow curves of drilling fluids are best explained by Herschel–Bulkley fluid because it has a yield stress value. The Herschel–Bulkley model is explained as follows (Srungavarapu et al., 2018).

$$\tau = \tau_o K(\gamma)^n \tag{3}$$

where n, K, γ, τ and τ_o are flow index, consistency index (Pa·s^n), shear rate (s^{-1}), shear stress (Pa), and yield stress (Pa), respectively.

From the shear rate versus shear stress results it can be speculated that, at first, the addition of low concentration of nanoparticles leads to disorganize the bonds between other drilling fluid additives which results in a significant reduction in shear stress. But then the shear stress starts to rise as the concentration of nanoparticles further increases because the quantity of nanoparticles dominate and the disrupting effect of nanoparticles reduces. Drilling fluids with low shear stress is required because it helps easy pumping while the drill bit is penetrating but it should have enough strength to be able to keep the cuttings in the suspension mode in static conditions (Dejtaradon et al., 2019).

It may be seen from Fig. 4b that the drilling fluid samples exhibit shear-thinning behaviour at 30 °C. Shear thinning behaviour of nanoparticle-based drilling fluid depends on the effective concentration of nanoparticles. Boron nitride shows hydrophobicity in the

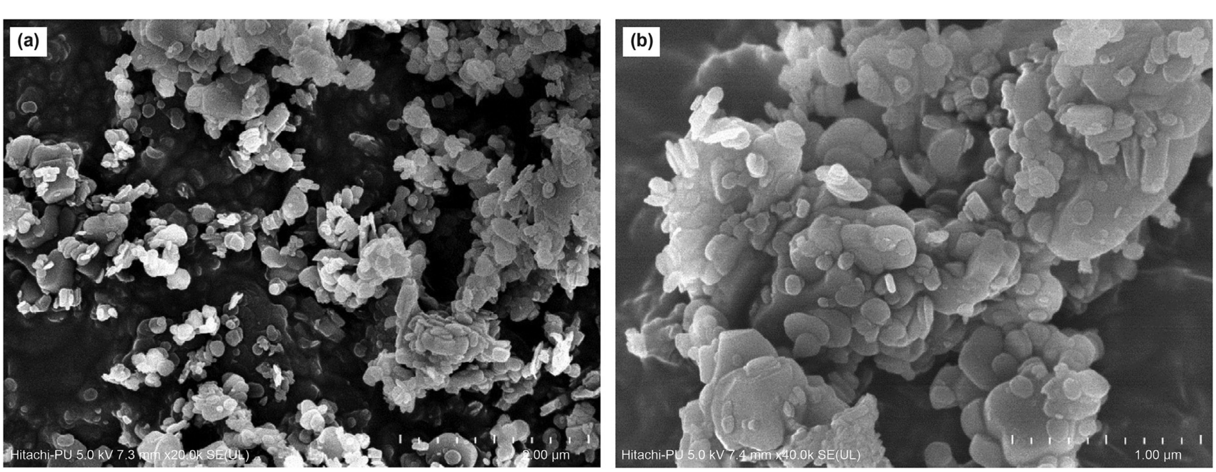

Fig. 3. SEM images of dry BN nanoparticles.

Table 2
The reported samples and their particle sizes.

Samples (Distilled water + BN nanoparticles)	Particle size of BN nanoparticles in distilled water, nm	Samples	Particle size of BN nanoparticles in polymer solution, nm
0.1 wt%	331.74	S2 to S4	2318.7
0.2 wt%	338.11	S5	2441.1
0.3 wt%	345.81	S6	2496.8
0.4 wt%	543.21	S7	3939.9
0.6 wt%	720.30	S8	6139.9

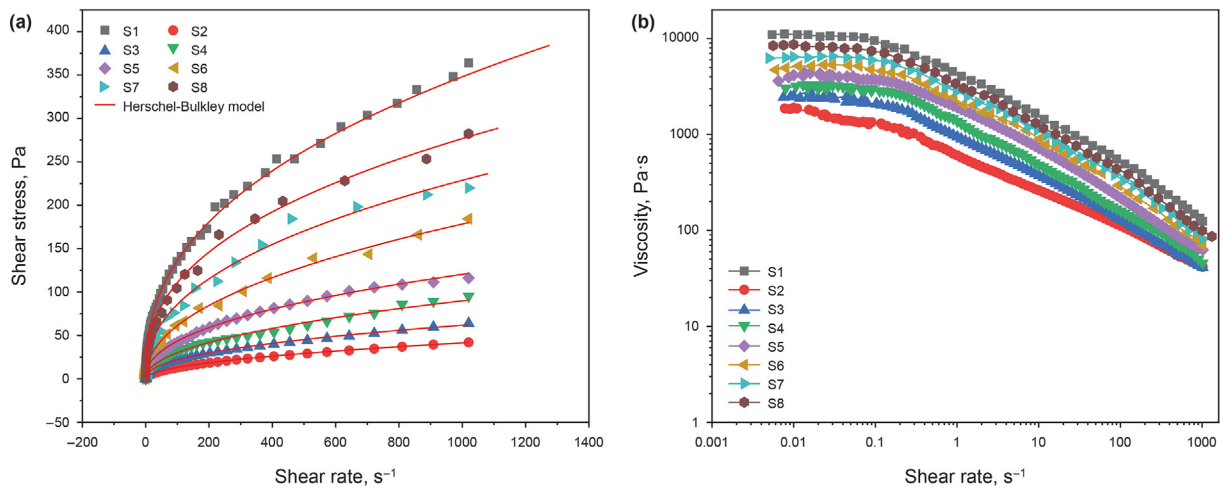

Fig. 4. Flow curves of different drilling fluids: (**a**) shear stress versus shear rate and (**b**) viscosity versus shear rate at 30 °C.

aqueous solution (Jedrzejczak-Silicka et al., 2018). In a polar medium such as water, particle-solvent interaction dominates and the liquid forms a solvent layer around them which acts as a preventer to form any network. BN nanoparticles have a tendency to form agglomerates. The linkage between aggregates are easily disturbed by high shear force. Higher fraction of inert solid in the drilling fluid rises the force of attraction (Żyła et al., 2015). Internal friction between nanoparticles increases with increasing concentration of nanoparticles. Thus, the viscosity increases with increasing concentration of nanoparticles and dispersions become increasingly shear thinning. At a constant low shear rate, the viscosity of the drilling fluid exhibits higher with higher amount of nanoparticles in the drilling fluid. Therefore, shear thinning properties also get prominent as the concentration of BN nanoparticles increases. A similar trend has been found in some literature (Dejtaradon et al., 2019). High viscosity at low shear rate helps in transporting cuttings from the bottom of the hole and keeping them in suspension when required. On the other hand, low viscosity at high shear rate is essential for facilitating mud pumping and releasing cuttings (Pakdaman et al., 2019). Cuttings carrying capacity also convincingly increases with the help of this shear thinning characteristics which is highly desirable in drilling operations (Xie et al., 2018).

3.4. Rheological properties of drilling fluids

3.4.1. Rheological properties at 30 °C

The information of rheological properties is very much important to predict the performance of drilling fluid. Plastic viscosity (PV) and yield point (YP) are the most important rheological parameters that should be described. Table 3 demonstrates all the following rheological parameters such as PV, YP, apparent viscosity (AV), gel strength, YP/PV, fluid loss, yield stress (τ_0), flow index (n), consistency index (K) and density. The addition of nanoparticles initially decreases the apparent viscosity and plastic viscosity but starts to enhance the viscosity with further addition of nanoparticles. This can be the indication of the fact that at low concentration, the main target of the nanoparticles is to interrupt the bridges created by clay platelets. This results in a decrease in the viscosity by reducing the hydrodynamic interaction between platelets. However, when the concentration of nanoparticles increases, the aggregation occurs due to increased Brownian motion and van der Waals attractive forces of the nanoparticles which leads to an increase in viscosity (Perween et al., 2018). The addition of guar gum solution to nanoparticle-enhanced drilling fluid also increases the viscosity of drilling fluid. The interaction between water molecules and the galactose side chain of the guar molecule is responsible for this enhancing result. Interaction of intermolecular chain is enhanced with increasing guar gum concentration (Mudgil et al., 2014). High viscosity of guar gum solution with nanoparticles is because of the interlink bond formed between them. Hexagonal BN nanoparticle has high curvature in their packing system which has the ability to increase interchain packing proximity. That can also significantly strengthen the interaction of polymer-nanoparticles which enhances the viscosity (Odziomek et al., 2017; Han, 2009). The complex interaction between polymer and nanoparticles are explained in Fig. 5. When the total concentration of nanoparticles and guar gum with other drilling fluid additives is lower, the intermolecular distance increases. Thus, intermolecular force weakens, which leads to the lower viscosity. As the concentration of additives increases, the intermolecular distance becomes shorter resulting in enhanced intermolecular force (Zhao et al., 2017). Thus, entanglement between particles happens with increasing concentration of additives. With increasing concentration of guar gum and nanoparticles in the drilling fluid, the plastic viscosity is the result of the friction between solid and solid phases and as well as the solid and liquid phases. Nanoparticle-based drilling fluid tends to reduce plastic viscosity compared to the drilling fluid without nanoparticles due

Table 3
Rheological properties of drilling fluids at 30 °C.

Drilling fluid	Density ρ, lb/gal	PV, mPa·s	YP Pa	AV, mPa·s	Gel strength, Pa		Fluid loss, mL	Yield stress τ_o	YP/PV	Flow index n	Consistency Index K, Pa·s^n	R^2
					10 s	10 min						
S1	9	24	20	43	11.49	23.94	16.5	0.72	0.83	0.51	0.85	0.99
S2	9	13	13	37	7.66	20.11	8.3	0.04	0.80	0.45	2.32	0.99
S3	10	14	13	38	8.14	20.58	8.1	0.12	0.88	0.43	2.24	0.99
S4	10	15	14	39	8.62	20.58	7.8	0.24	1.13	0.42	2.51	0.98
S5	11	16.5	15	39.5	9.09	21.06	7.5	0.21	1.07	0.45	5.32	0.99
S6	12	17	16	40	9.58	21.55	7.0	0.61	1.11	0.41	4.59	0.98
S7	13	17.5	17	40.5	9.58	22.50	6.5	1.51	1.13	0.39	5.94	0.97
S8	12	18	19	41	9.09	21.55	6.3	1.43	1.14	0.35	6.24	0.98

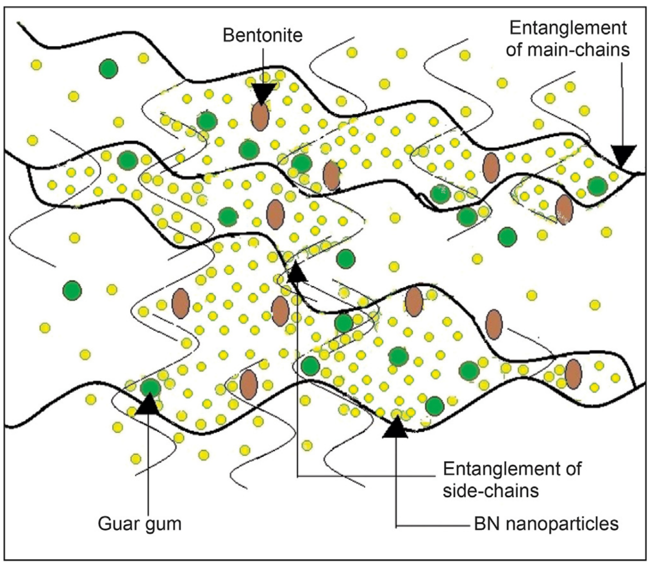

Fig. 5. Complex interaction between polymer-nanoparticles.

to the result of the reduction of mechanical friction between the additives in the drilling fluid (Liu et al., 2016a). This is helpful for easy fluid flow within the drill bit and in the annulus as high plastic viscosity could slow down drilling fluid pumping. Low apparent viscosity at high shear rate would be able to penetrate the drill bit faster when operation starts. Initial resistance of the drilling fluid to flow is reduced by nanoparticle-based drilling fluid (Wang et al., 2018). Reduction of yield point with an addition of little amount of BN nanoparticles is due to the lower electrochemical force between the drilling fluid additives (Perween et al., 2018).

For deepwater drilling environment, the fluid stability and rheological properties are very important. Nano-sized particle has the ability to enhance the rheological properties with a significant reduction in fluid loss volume. Enhanced rheological properties will reduce the problem of excessive torque and drag, and insufficient hole cleaning. Reduction in fluid loss will effectively minimize the borehole instability problem. Rheological results mentioned in Table 3 show that, plastic viscosity slightly decreases with the addition of little amount BN nanoparticles to the S1 sample, but again increases with further addition of BN nanoparticles. A similar trend was observed for yield point values. However, these variations are only marginal. Therefore, BN nanoparticles are very effective in deepwater drilling environment. Lost circulation is one of the most troublesome problems in deepwater drilling operations. Lost circulation is an unwanted event where only a small amount of drilling fluid is returned from the wellbore, which is very little than the amount of drilling fluid pumped into it (Alcázar-Vara and Cortés-Monroy, 2018). Thus, drilling fluid is lost into the formation. It is one of the major causes of nonproductive time (NPT) which increases the cost of operations. Here, BN nanoparticle-based drilling fluid helps in controlling the lost circulation by reducing the fluid loss volume. Experiment performed by Alvi et al. (2018) using Fe_2O_3 nanoparticles shows that these nanoparticles have similar rheological properties to that of BN nanoparticles. But, Fe_2O_3 nanoparticles does not show any significant effect on fluid loss volume. Thus, using these nanoparticles in deepwater drilling fluid would create problems by damaging the formation. So, as compare to Fe_2O_3 nanoparticles, BN nanoparticles is better in deepwater drilling operation. Hydroxyethyl cellulose (HEC) polymer is also popularly used as fluid loss additives in drilling fluid but they can work better under normal operation condition as reported by Arisz et al. (2006). This polymer is not suitable for low temperature and high-pressure conditions. But, BN nanoparticle-based drilling fluids provide acceptable fluid loss control under low temperature and high pressure conditions. Bentonite is usually used as drilling fluid additives because of its unique swelling properties and excellent rheological properties. But, sometimes it is used purely because of its fluid loss control property as it helps in reducing the fluid loss of drilling fluid. Because of its high viscosity nature, bentonite forms a thick filter cake and reduces fluid loss. But, bentonite is less degradable and unstable at high pressure conditions (Song et al., 2016). Thus, bentonite is not suitable as fluid loss additives in deepwater drilling operations. Thus, bentonite can be used along with BN nanoparticles as fluid loss additives as it has the capability to reduce the fluid loss volume. Navarrete et al. (2000) discussed how xanthan gum can be used as a fluid loss controller. But, it was seen from the literature that, xanthan gum alone cannot control the fluid loss volume effectively. Another fluid loss additives are required to decrease the fluid loss volume significantly. Whereas, BN nanoparticles have the capability to reduce the filtration loss volume alone very effectively.

A better optimized value of gel strength than S1 sample (without nanoparticles) is required to decrease the pump power needed to recirculate flow during static mode and it was achieved using BN nanoparticles. The value of gel strength at 10 min suddenly decreases at 0.6 wt% concentration. This implies that the nanoparticles were close to each other at this concentration, thus they act like large particles due to agglomeration (Smith et al., 2018). Relationship between yield point and plastic viscosity is important in determining the ability of drilling fluid in well cleaning operations. High YP/PV ratio helps in increasing the capacity of drilling fluid to carry cuttings, which leads to an increase in pump's performance (Zhao et al., 2015b). Although S7 and S8 samples are having almost similar YP/PV ratio, but S7 sample has lower plastic viscosity which is required for drilling bit. The plastic viscosity and yield point of S7 sample which is similar to the experimental results from Chu and Lin (2019), can be considered as desirable values for drilling fluid. Works of Jain and Mahto (2015) also concluded that the plastic viscosity of nanoparticle-enhanced drilling fluid in the range of 20–29 mPa·s is considered optimized as it confirms the circulation without inducing frictional pressure losses. So, S7 sample is considered optimized sample amongst the all drilling fluids.

Lower flow index value (n) has a better ability to carry cuttings from the bottom of the hole to the surface. Thus, lower n value is required for drilling fluid to have better cuttings carrying capacity. Consistency index (K) is the measure of the consistency of the fluid. Higher consistency index indicates higher viscosity which helps in carrying the cuttings from the hole to the surface. Otherwise, cuttings will settle down as they have a tendency to settle down due to the gravity if K is low. Ofei (2016) mentioned that consistency index (K) near 6.3 Pa·s^n increases the cuttings carrying capacity and flow index (n) less than 1 is favourable for drilling fluid to carry cuttings easily. S7 sample has a desirable range of n and K values which are similar to that reported by Ofei (2016). Therefore, for further studies, only S7 sample has been considered. In this study, the improvement of rheological properties resulting from increasing nanoparticle concentration is consistent with results from Dejtaradon et al., (2019).

3.4.2. Viscoelastic properties

Oscillatory tests are used to determine the viscoelastic properties of drilling fluids. Sample exhibits both elastic and viscous characteristics when undergoing deformation. Oscillatory tests such as amplitude sweeps were tested to get an indication about their short- and long-term structural behaviour (Werner et al., 2017). Amplitude sweep was the first test to define storage modulus (G'), loss modulus (G'') and linear viscoelastic range (LVER) of the sample. The storage modulus (G'), also known as elastic modulus, signifies the deformation energy which is stored by the sample during a shear process. Whereas the loss modulus (G''), the viscous behaviour of sample, is the representation of the deformation energy which has been used up by the sample during the shear process (Mezger, 2009). The other important parameter is the LVER which indicates the strain range where G' and G'' curves shows parallel trends until the inner structure of the sample breaks up (i.e., the crossover point). Fig. 6 presents amplitude sweep results of different samples. According to the graphs, all the samples behave solid-like structure at low strain value as G' has higher value than G'' till the crossover point. As the strain increases after the crossover point, the value of G' drops and G'' value rises ($G' < G''$) and the sample behaves more like a liquid-like and viscous structure. The crossover point signifies the overlapping point of storage modulus and loss modulus, at which $G' = G''$. This crossover point can also be taken as a yield point, as this is the indication of the transition from solid to liquid characteristics. LVER range for some weakly structured sample is very small (S1 sample in Fig. 6a). So, these samples under the deformation, will rapidly change from viscoelastic range to viscous range. S7 and S8 samples (Fig. 6b) have comparatively larger linear viscoelastic range as well as larger maximum strain of linear viscoelastic range. Therefore, these samples (S7 and S8) can deform without internal breaking of the gel structure for a longer time compared to other samples. The presence of BN nanoparticles caused increases in storage modulus (G') and loss modulus (G'') values of S1 sample (without nanoparticles), possibly due to the intermolecular interaction within the structure of the fluid resulting from the presence of the nanoparticles. The G' value of all the samples as shown in Fig. 6 initially increases within a certain lower strain range before it attains plateau. This enhancement is a traditional effect of the fluid as it shifts from static to dynamic and the Brownian force is responsible for this behaviour which reorganizes the fluid into a more crystalline structure (Werner et al., 2017). The G' value of all the samples shows almost constant values until a strain of around unity is reached. This replicates pure dispersive state of the samples. Before the unity value of the strain comes, suspended particles are kept in a position trying to reach an energy minimum. As the strain becomes larger, particles start to jump which destroys the structure of the sample, therefore reducing the G' value. Here, the gel points of different samples were varying. With increasing nanoparticle concentration, the gel point shifted towards higher shear strain. A strong gel is very important for drilling fluid to keep the particles in suspension mode. Higher viscoelastic fluids normally relate to stronger gel structures. High linear viscoelastic range and high yield point signify the prevention of particle settlement. The viscoelastic behaviour of S7 drilling fluid obtained from the experiments implies that the sample is flexible in changing its rheological properties while drilling. Table 4 listed all the viscoelastic properties such as the storage modulus and loss modulus at the end of LVER, and the ratio of their values (G''/G') which represents the loss factor ($\tan\delta$, $\tan\delta = G''/G'$).

Frequency sweep test was conducted to understand the influence of different frequencies on nanoparticle-based drilling fluid. Cross point and linear viscoelastic range may also change with frequency. Frequency sweep tests of all the samples follow the similar form but the cross point and LVER range may vary.

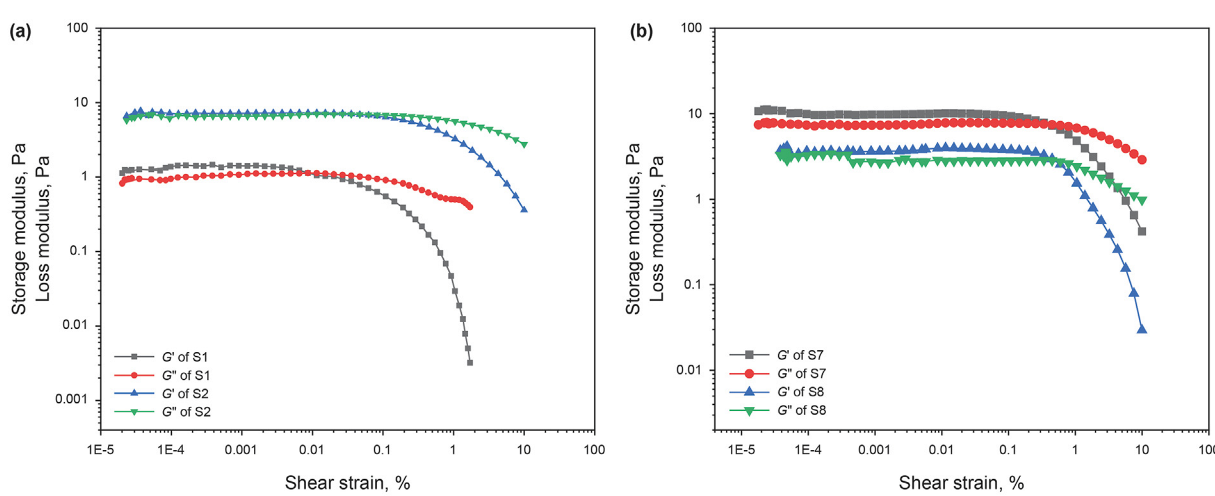

Fig. 6. Amplitude sweep showing storage modulus and loss modulus of different samples.

Table 4
Storage modulus, loss modulus and loss factor.

Sample	Storage modulus G', Pa	Loss modulus G'', Pa	Loss factor tanδ
S1	1.38	1.09	0.78
S2	6.89	6.81	0.98
S3	7.28	7.03	0.96
S4	7.31	6.94	0.94
S5	12.01	7.32	0.61
S6	2.91	1.83	0.62
S7	3.71	2.82	0.76
S8	10.01	7.81	0.78

Frequency is the inverse of time; thus, these tests were used to investigate time dependent deformation behaviour. High frequency indicates fast deformation and low frequency to slow deformation. Experimental data in Fig. 7a shows that for some of the samples, the elastic modulus is nearly independent of frequency. But for most of the samples, the elastic modulus is dependent on frequency (Fig. 7b). For S2 sample, the elastic modulus is lower than the viscous modulus in low frequency range implying viscous nature of the fluid. But for the most of the samples in the whole investigated frequency range, the storage modulus is higher than the loss modulus, indicating dominated elastic behaviour. Here, dispersions and gels are build up by a physical network of intermolecular forces between nanoparticles and polymer particles (Bera et al., 2020). For drilling fluid, a stable structure is required to keep the cuttings in suspension mode. A similar trend of curves has also been reported by Ozbayoglu (2008). S7 sample has a better steady structure as well as better dynamic yield point which are important for drilling fluid to keep small particles in suspension. So, it can be concluded that S7 sample provides better viscoelastic behaviour than the rest of the samples. Rheological properties of this sample also provide optimizing results, thus for further study S7 sample has been considered.

Loss factor (tanδ) is another important property to categorize the viscoelastic nature of the sample in terms of solid and liquid. When, tan$\delta < 1$ (where tan$\delta = G''/G'$), the sample behaves more elastically whereas, for tan$\delta > 1$, sample behaves viscous flow. Loss factor tan$\delta < 1$ indicates dominance of storage modulus than loss modulus whereas loss factor tan$\delta > 1$ indicates greater value of loss modulus. Here, all the samples exhibit (Table 4) elastic behaviour as tan$\delta < 1$. Loss factor (tan δ) reveals the ratio of the viscous and elastic portion of the viscoelastic deformation behaviour. As the shear strain increases, the value of loss factor increases (tan$\delta > 1$) which indicates viscous character.

3.4.3. Comparison of rheological properties between conventional drilling fluid and drilling fluids with and without nanoparticles at low temperature

Temperature is one of the most important factors that have an effect on hydration and viscosity of drilling fluid (Mudgil et al., 2014). To study the influence of temperature on rheological properties of different drilling fluids, numerous investigations have been done (Jaffal et al., 2017; Benchabane and Bekkour, 2008). The rheological properties of several water-based drilling fluids have been examined under deepwater drilling conditions (Ofei, 2016; Ozbayoglu, 2008) and significant changes in rheological properties were also observed at different temperatures. The main difference between offshore (deepwater) and onshore drilling is the temperature difference. For deepwater drilling, the temperature generally lies below 25 °C. Plastic viscosity is very much dependent on low temperature, especially below 25 °C. Consequently, an adequate drilling fluid is necessary to drill under the low-temperature conditions (Zhao et al., 2015b). For such drilling operations, the temperature range used in this experiment was from 10 °C to −5 °C, the chosen lowest temperature is −5 °C to describe the dependence of rheology of drilling fluid at such low temperature.

To see the influence of temperature on different drilling fluids, a comparison of rheological properties between conventional drilling fluid and drilling fluids with and without BN nanoparticles has been conducted under different low temperatures. Plots of shear stress versus shear rate of all three types of samples at different low temperatures are shown in Fig. 8. It can be clearly seen that, the shear stress of all the samples is getting higher as the temperature decreases. In the case of the conventional drilling fluid, the shear stress with respect to shear rate is comparatively lower than that of the drilling fluids with and without BN nanoparticles. Viscosity as a function of shear rate for all the three samples has been plotted in Fig. 9. At decreasing temperature, all the drilling fluid samples still exhibit shear thinning behaviour. This shear thinning properties of drilling fluids with nanoparticle additive at lower temperature implies their ability to still function at low temperature. Benchabane and Bekkour also reported shear thinning behaviour at all shear rates (Benchabane and Bekkour, 2008). At low shear rates, the sample encounters higher viscosity due to the entanglements of polymer coils. It is accepted that shear thinning behaviour is found because of the disentanglement of the polymer coils in the drilling fluid solution (Clasen and Kulicke, 2001).

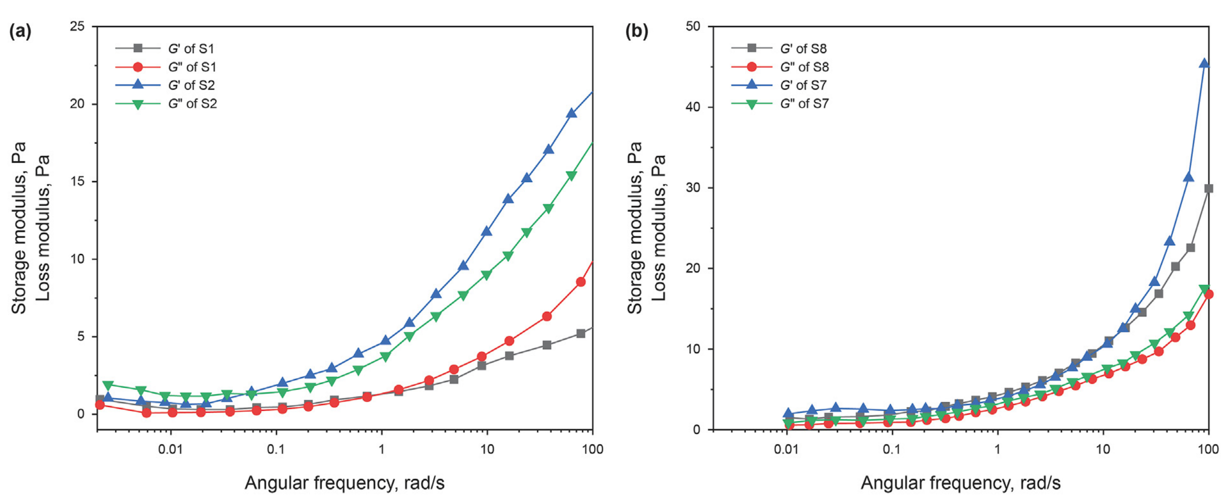

Fig. 7. Storage modulus and loss modulus of (**a**) S1 and S2 samples and (**b**) S7 and S8 samples at different frequency sweeps.

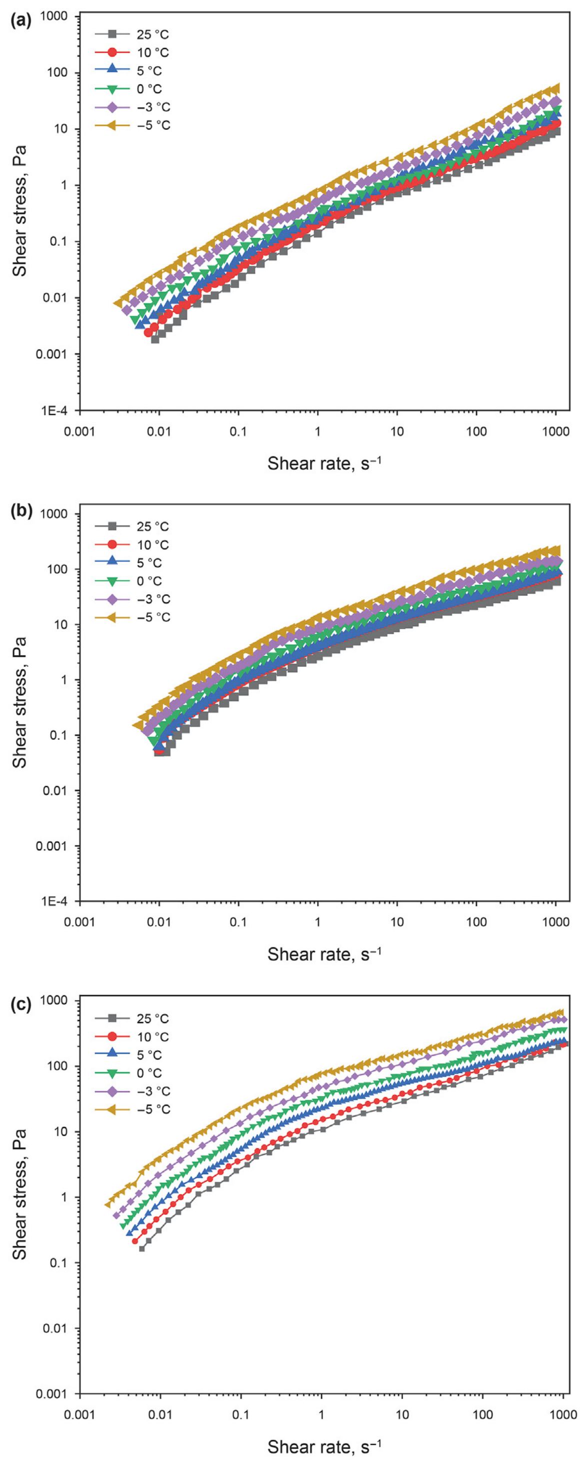

Fig. 8. Flow curves of (**a**) conventional drilling fluids, (**b**) drilling fluid without BN nanoparticles, and (**c**) drilling fluid with BN nanoparticles at different temperatures.

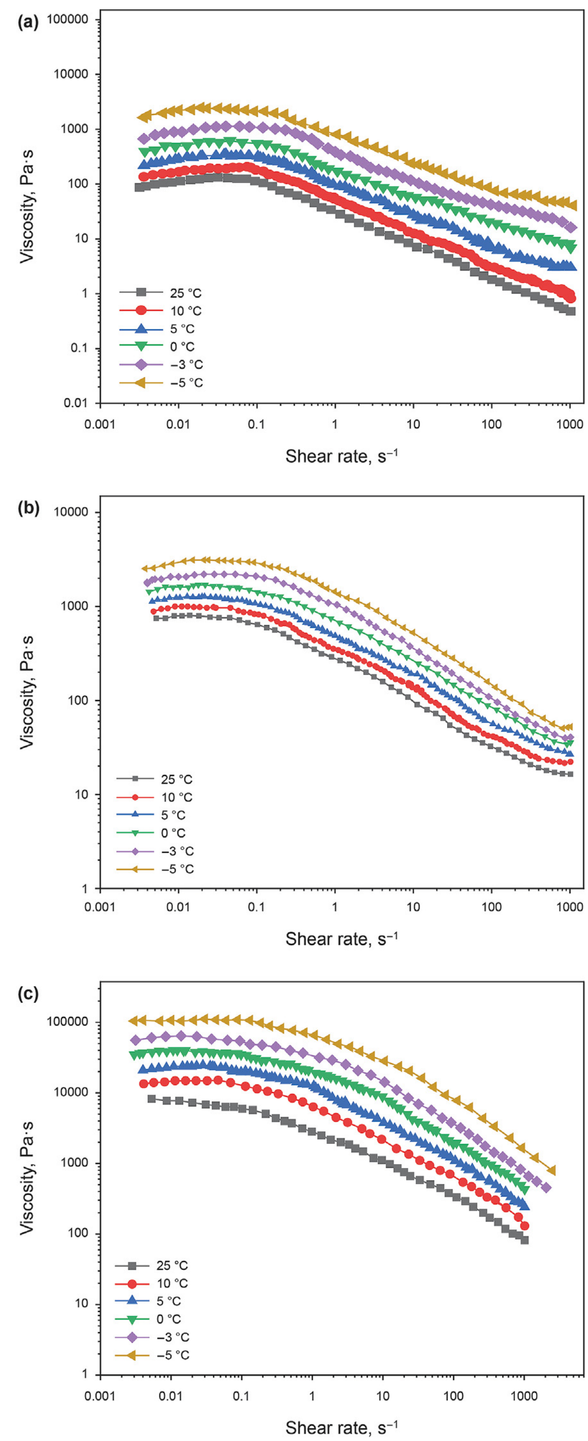

Fig. 9. Viscosity versus shear rate curves of (**a**) conventional drilling fluid, (**b**) drilling fluid without BN nanoparticles, and (**c**) drilling fluid with BN nanoparticles at different temperatures.

All the rheological parameters of the reported conventional drilling fluid, nanoparticle-based drilling fluid and drilling fluid without nanoparticles were determined and mentioned in Table 5. Consistency index (K) indicates the consistency of the fluid and it is proportional to the effective viscosity. Thus, drilling fluids with lower K value will not help to carry cuttings as the gravity will settle down the cuttings (Ofei, 2016). With decreasing temperature, the values of K and flow index (n) increase for all types of drilling fluids. It is to be seen that, the conventional drilling fluid has lower flow index and consistency index in comparison to other two fluid samples. The nanoparticle-based drilling fluid shows higher amount of consistency index than the drilling fluid without nanoparticles. Annular velocity rises with the value of the consistency index, which helps in cleaning hole capacity (Sadeghalvaad and Sabbaghi, 2015). In accordance to Herschel–Bulkley model $n < 1$ indicates shear thinning behaviour. Lower flow index is effective for

Table 5
Rheological properties of all three types of drilling fluids at different temperatures.

Drilling fluid	Temperature, °C	Plastic viscosity (PV), Pa	Yield point (YP), Pa	YP/PV	Yield stress τ_o, Pa	Flow index n	Consistency index K, $Pa \cdot s^n$	R^2
Conventional drilling fluid	25	10.48	13.72	0.76	0.02	0.59	0.14	0.997
	10	21.57	16.94	0.78	0.04	0.6	0.19	0.997
	5	24.73	19.53	0.79	0.07	0.61	0.47	0.994
	0	27.49	22.94	0.83	0.23	0.78	0.29	0.996
	−3	32.49	27.38	0.84	0.24	0.87	0.33	0.998
	−5	35.68	30.37	0.85	0.27	0.89	0.49	0.998
Drilling fluid without BN nanoparticles (S1)	25	36.27	40.54	0.89	0.19	0.39	3.78	0.997
	10	49.37	45.24	0.92	0.21	0.42	4.81	0.997
	5	52.93	48.89	0.92	0.47	0.42	6.56	0.994
	0	54.92	51.73	0.94	0.53	0.58	7.19	0.996
	−3	59.83	56.95	0.95	1.00	0.61	11.88	0.998
	−5	62.49	59.83	0.96	1.10	0.69	15.63	0.998
Nano-based drilling fluid (S7)	25	35.26	29.48	0.83	0.42	0.38	9.47	0.994
	10	40.67	35.14	0.86	1.45	0.44	15.77	0.994
	5	46.55	41.39	0.89	1.06	0.46	23.7	0.995
	0	52.68	48.94	0.92	1.19	0.47	30.01	0.996
	−3	54.99	51.07	0.92	3.51	0.51	53.73	0.995
	−5	57.00	53.83	0.9	3.69	0.52	74.59	0.996

better cuttings carrying capacity. The nanoparticle-based drilling fluid has lower flow index (n) value than that of the drilling fluid without nanoparticles. For S7 sample, the values of n and K are in range of desirable value. A similar range of flow and consistency value is also provided by Ofei (2016). Thus, nanoparticle-based drilling fluid is more favourable in drilling industry than other two samples mentioned above.

The impact of temperature on plastic viscosity and yield point of all three types of sample fluids are mentioned in Table 5. For the conventional drilling fluid, there is a drastic change in rheological properties with decreasing temperature. Whereas, other two samples show comparatively stable rheological properties. Samples with and without nanoparticles have an increasing trend of plastic viscosity and yield point with decreasing temperature, which happens due to the reduction in Brownian motion and acceleration in dispersion. Zhao et al. (2017) indicated that bentonite with rich in montmorillonite clay mineral is the better option for increasing the plastic viscosity and yield point of the drilling fluid. Therefore, as the temperature decreases, each single platelet in bentonite dispersion decreases which attributes to an increase in plastic viscosity. Guar gum is a high molecular polymer. Thus, when the temperature reduces, molecular entanglement helps bond strength between particles to get stronger, thus plastic viscosity increases. High yield point requires to clean the bottom of the borehole. The nanoparticle-based drilling fluid shows desirable values of plastic viscosity and yield point than the conventional drilling fluid and the drilling fluid without nanoparticles. This range of plastic viscosity and yield point is quite desirable as similar results have been found by some other researchers (Perween et al., 2018; Jain and Mahto, 2015). Thus, comparing all the three drilling fluids mentioned below in Table 5, it can be said that nanoparticle-based drilling fluid is favourable to use in the drilling industry.

3.4.4. Comparison of rheological properties between conventional drilling fluid and drilling fluids with and without nanoparticles at high pressure

In deepwater reservoirs (offshore), gas hydrate formation occurs easily at a favourable condition of high pressure, which would lead to a serious problem by blocking the pipeline and/or blowout preventers. At present, there are several ultra-deep wells drilled in water depth more than 3000 m. The South China Sea is one of them where the water depth is about 3000 m and the pressure of the sea bed is about 30 MPa (Zhao et al., 2015b). High pressure has the capability to impact the rheological characteristics of a drilling fluid by changing physical, chemical and electrochemical properties of the fluid. The influence of temperature and pressure on the water-based drilling fluid are very distinctive that is increasing temperature reduces the viscosity because of the thermal expansion, whereas increasing pressure increases the viscosity because of the compression. For many years, numerous studies have been performed to correlate the rheology of the drilling fluid with pressure (Karimi Vajargah and van Oort, 2015). In the present study, the dependence of drilling fluid rheology on pressure has been investigated by increasing pressure from 1 MPa to 28 MPa to see the rheological changes of the water-based drilling fluid. Shear stress of all the samples is getting higher with increasing pressure as seen from Fig. 10. These figures show that the conventional drilling fluid has lower shear stress than samples with or without BN nanoparticles. At high pressures, all the samples maintain to exhibit shear thinning behaviour as shown in Fig. 11. These figures demonstrate that nanoparticle-based drilling fluid has higher viscosity compared to the conventional drilling fluid and the sample without nanoparticles. At very low shear rate, the viscosity is higher because of the entanglements between the molecule chains of the used polymer. It is appropriate for hole cleaning at varying shear rate and helps carry the cuttings from the bottom of the hole to the surface.

Consistency index (K) which indicates the viscosity of the sample is directly proportional to the pressure. Thus, with increasing pressure, the cuttings carrying capacity for the sample also enhances as shown in Table 6. Whereas, the flow index (n) decreases with increasing pressure. Cuttings carrying capacity of a sample can also be identified by n value, as lower n value has better cuttings transporting capability. Thus, with higher pressure, cuttings carrying capacity increases (Briscoe et al., 1994). The plastic viscosity and yield point increase with pressure for all three types of drilling fluids as exhibited in Table 6, because high pressure results in compressing of the sample's molecules. The conventional drilling fluid has very low plastic viscosity and yield point compared to other two types of drilling fluids which is not desirable. The drilling fluid with BN nanoparticles has lower plastic viscosity compared to the sample without nanoparticles. The

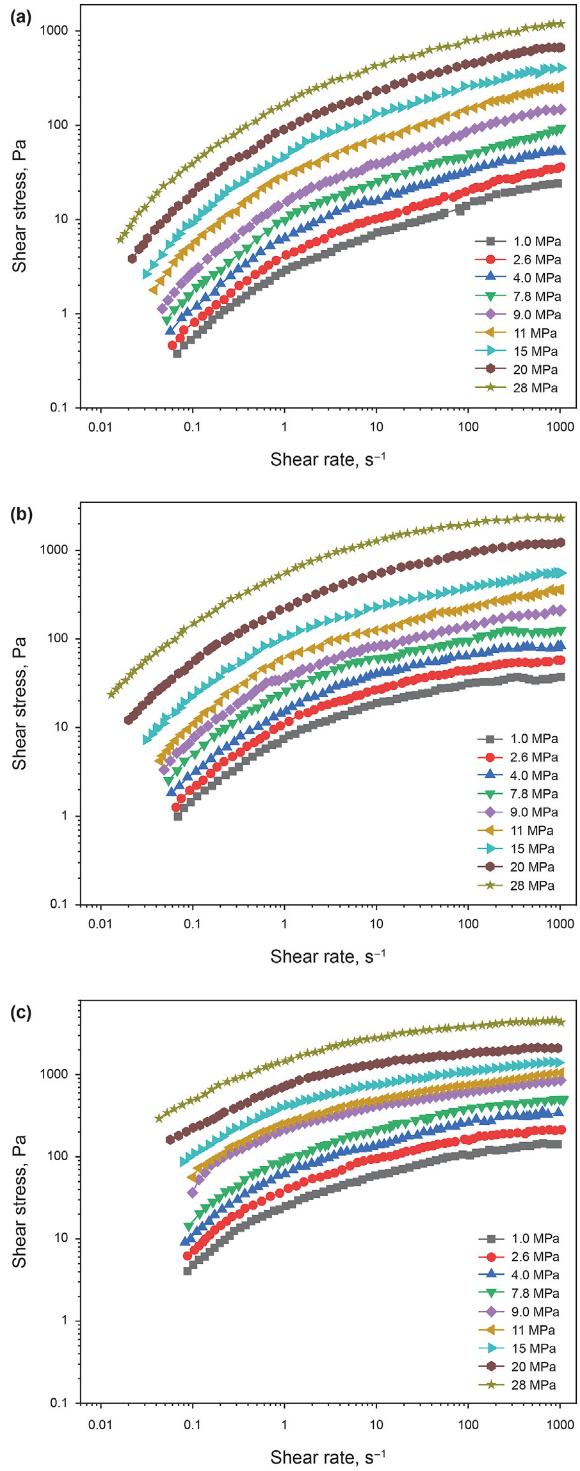

Fig. 10. Flow curves of (**a**) conventional drilling fluid, (**b**) drilling fluid without BN nanoparticles, and (**c**) drilling fluid with BN nanoparticles at different pressures.

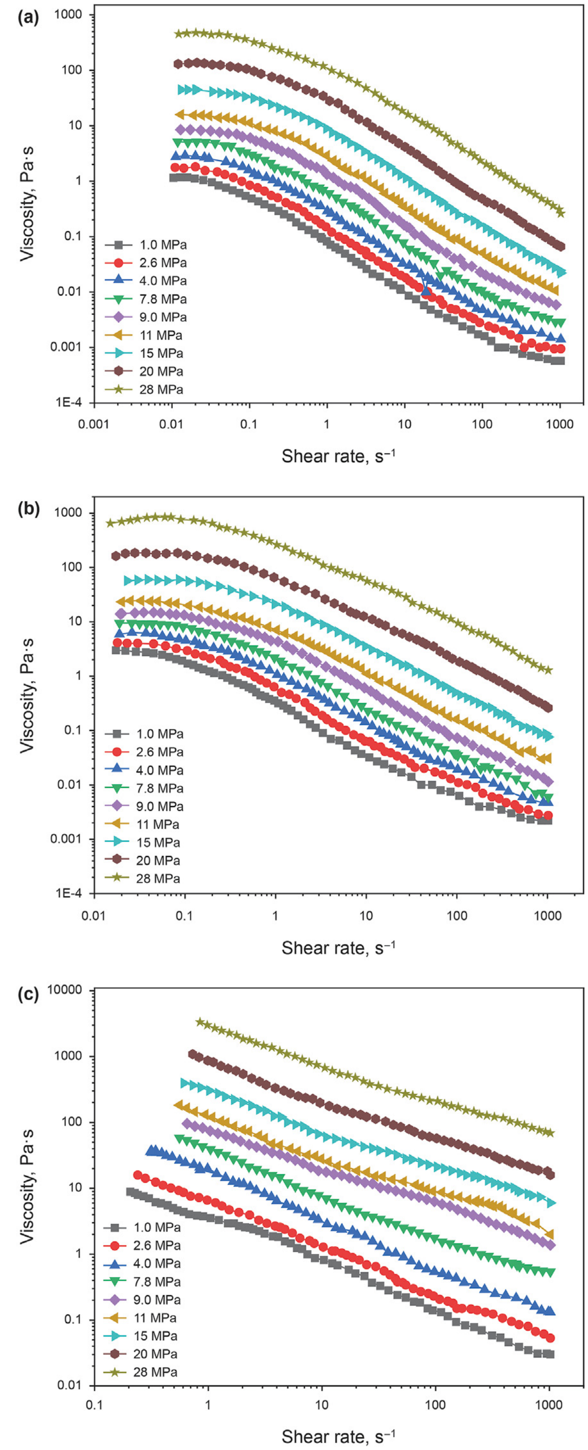

Fig. 11. Viscosity versus shear rate curves of (**a**) conventional drilling fluid, (**b**) drilling fluid without BN nanoparticles, and (**c**) drilling fluid with BN nanoparticles at different pressures.

nanoparticle-based drilling fluid causes a reduction in plastic viscosity because nanoparticles may reduce the mechanical friction between particles in the sample. This helps in easy flowing of the sample through the drill bit and in the annulus. The yield point of the nanoparticle-based drilling fluid is lower than the sample without nanoparticles, which also helps in reducing the electromechanical force between particles in the drilling fluid (Dejtaradon et al., 2019). High YP/PV ratio at high pressure indicates that high pressure has a better influence on yield point than plastic viscosity. As the plastic viscosity is dependent on mud weight and that does not change with pressure, thus high pressure does not have the ability to influence plastic viscosity as much as it does to yield point. Briscoe et al. (1994) and Hassiba and Amani (2012) also reported similar results.

Table 6
Rheological properties of conventional drilling fluid, and drilling fluids with and without BN nanoparticles at different pressures.

Drilling fluid	Pressure, MPa	Plastic viscosity (PV), Pa	Yield point (YP), Pa	YP/PV	Yield stress τ_o, Pa	Flow index n	Consistency index K, Pa·s^n	R^2
Conventional drilling fluid	1.0	14.37	18.35	1.28	0.44	0.29	3.46	0.994
	2.6	16.34	21.48	1.31	0.65	0.3	5.17	0.997
	4.0	19.38	25.89	1.33	1.37	0.27	8.79	0.996
	7.8	28.59	38.45	1.34	1.25	0.3	12.01	0.992
	9.0	34.49	46.48	1.35	2.38	0.31	19.04	0.997
	11.0	40.38	55.24	1.37	3.98	0.3	35.13	0.992
	15.0	44.27	62.45	1.41	9.47	0.28	65.61	0.994
	20.0	49.34	70.21	1.42	17.07	0.27	116.75	0.997
	28.0	55.41	79.66	1.44	28.52	0.26	210.68	0.993
Drilling fluid without BN nanoparticles (S1)	1.0	21.49	28.48	1.32	3.24	0.21	10.30	0.996
	2.6	32.58	43.59	1.34	4.20	0.22	15.14	0.997
	4.0	41.46	56.19	1.35	6.82	0.23	22.48	0.998
	7.8	49.28	66.97	1.36	10.12	0.22	34.24	0.997
	9.0	52.48	70.83	1.35	6.99	0.25	42.19	0.999
	11.0	55.27	75.83	1.36	9.27	0.25	66.37	0.997
	15.0	59.48	81.67	1.37	19.08	0.24	120.12	0.993
	20.0	63.12	87.49	1.39	54.33	0.23	285.23	0.995
	28.0	66.21	91.85	1.39	147.84	0.22	643.80	0.997
Nano-based drilling fluid (S7)	1.0	19.93	24.39	1.22	12.33	0.22	39.65	0.995
	2.6	25.57	32.48	1.27	23.22	0.20	65.77	0.997
	4.0	35.58	45.87	1.29	41.28	0.27	86.80	0.996
	7.8	44.73	57.92	1.3	33.17	0.22	123.61	0.998
	9.0	49.63	65.93	1.31	78.47	0.22	269.54	0.997
	11.0	52.46	69.38	1.32	58.19	0.20	281.88	0.999
	15.0	56.28	75.64	1.34	109.24	0.19	441.19	0.994
	20.0	61.54	82.27	1.34	271.39	0.17	796.74	0.993
	28.0	65.49	88.35	1.35	543.69	0.16	1164.91	0.991

3.4.5. Zeta potential at low temperature

Zeta potential is generally treated as temperature and pressure independent. But, nowadays, some experimental results prove that zeta potential can be influenced by temperature and pressure (Rodriguez and Araujo, 2006). Zeta potential of the drilling fluid (S7 sample) was measured over a temperature range of 0–30 °C and the experimental results are shown in Fig. 12. The results clearly indicate that the zeta potential of the sample becomes more negative as the temperature reduces but then the value becomes almost constant as the temperature decreases further. The zeta potential of S7 sample is negative because of the higher surface area of BN nanoparticles which tends to increase the dimmer species concentration leading to increasing ability of the particles to capture OH^- groups. This increases the zeta potential towards more negative. Low boric acid content is also responsible for lower zeta potential value of the sample (Bouville and Deville, 2014). The pH value of the sample is 8.2 which is in the optimum range because this range will provide lower plastic viscosity of the drilling fluid. This helps to increase the penetration rate and minimize the total cost (Gamal et al., 2019). Thus, it can be concluded that lower temperature does not have any significant effect on zeta potential value of the chosen sample (S7). This similar type of behavior is also reported in literature (Rodriguez and Araujo, 2006).

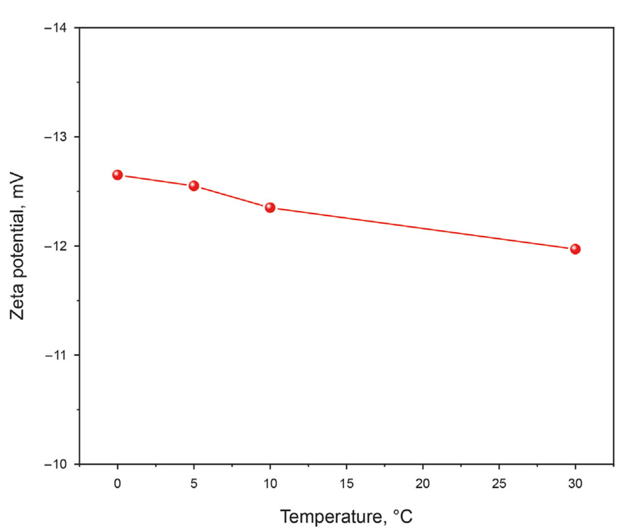

Fig. 12. Zeta potential of S7 sample at different low temperatures.

3.4.6. Mechanism of influence of low temperature and high pressure on S7 drilling fluid

The effects of low temperature on the structures of different additives were investigated by zeta potential measurements. The zeta potential values of S7 sample are shown in Fig. 12. It indicates that for the suspension of BN nanoparticles and clay particles, the absolute value of zeta potential slightly increases with a decrease in temperature (from 30 °C to 0 °C). Higher negative zeta potential value at lower temperature indicates the strong diffusion ability of the cations in the diffusion layer. As the temperature increases, the repulsive force between clay particles becomes weak and the dispersion degree of clay suspensions also decreases (Zhao et al.,

Table 7
Sizes of particles in the drilling fluid (S7 sample) at different low temperatures.

Temperature, °C	Particle size, nm
30	6139.9
10	6182.5
5	6210.3
0	6231.7

2017).

Table 7 represents the sizes of particles in the drilling fluid at different low temperatures. There is no significant difference between the particle size at different low temperatures which indicates that low temperature had no significant effect on the particle size of the sample.

The viscosity of a polymer is denoted by the free volume of a polymer solution and molecular entanglement under a particular shear rate. From Fig. 9 and Table 5, we can see that the viscosity of the polymer solution increases with a decrease in temperature. At higher temperature, the thermal motion of molecules is strong and the space between molecules also increases, resulting in weak intermolecular forces and friction (Zhao et al., 2017). Thus, water molecules are being able to move freely and reduces flow resistance.

Viscosity of the polymer solution increases with an increase in pressure. Under high pressure, the movement of the molecules within the fluid becomes constrained and the relative motion is hindered. Intermolecular force decreases and flow resistance becomes high enough to slower the flow of water molecules (Aluova et al., 2019). Thus viscosity increases with increase in pressure.

3.4.7. Influence of temperature and pressure on filtration properties

Filtration of drilling fluid at different low temperatures is vital in deepwater drilling operations; lost circulation can damage the formation. Pressure imbalance between wellbore and formation can damage the formation. In static filtration operation under low temperatures, BN nanoparticles and guar gum can support other colloids to be in suspension mode and prevent it from sagging, which finally minimize the total fluid loss volume. However, to attest this, filtration tests were conducted at low temperature and high pressure to investigate the effect of temperature and pressure on filtrate loss. A round of tests was conducted to see the effect of temperature on the total fluid loss volume of S7 sample. According to Fig. 13, the total fluid loss volume decreased with decreasing temperature due to the stronger filter cake with reducing temperature. Increasing temperature will lead to a decrease in gel viscosity, which consequently increases the fluid loss. Fluid loss volumes of S7 sample were also measured at different high pressures. It was observed from Fig. 13 that the fluid loss volume increased with pressure but it was negligible as the high pressure does not have much effect on plastic viscosity and the filtrate loss is mainly governed by viscosity.

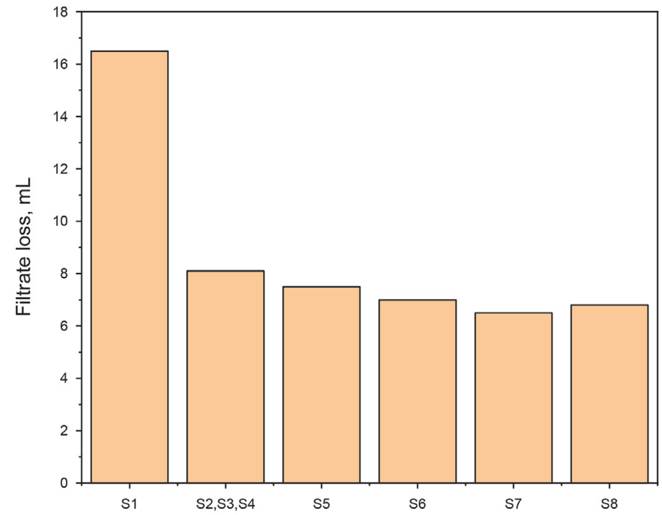

Fig. 14. Effect of BN nanoparticle concentration on filtrate volume.

3.5. Influence of different additives on filtration properties

API filtrate loss should be as low as possible for any water-based drilling fluid because otherwise wellbore instability problems will arise in the case of water-sensitive formation like shale (Ofei, 2016; Perween et al., 2018). Due to the pressure difference between the walls, filtrate loss occurs. This leads to the formation of filter cake with the deposition of the solids in the drilling fluid. The filtrate reducers of water-based drilling fluids are mainly polymers and some nanoparticles. The concentration of BN nanoparticles in the drilling fluid largely affects fluid loss volume as shown in Fig. 14. According to the results, the filtrate volume of S1 sample (without nanoparticles) was 16.5 mL, which was the highest. The lowest filtrate volume was recorded for sample with 0.4 wt% BN nanoparticles (S7 sample) which was 6.5 mL. This indicates a 60.6% reduction in fluid loss volume for S7 sample compared to S1 sample. The ability of a drilling fluid to create a thin and low permeability filter cake can be determined from the reduction in

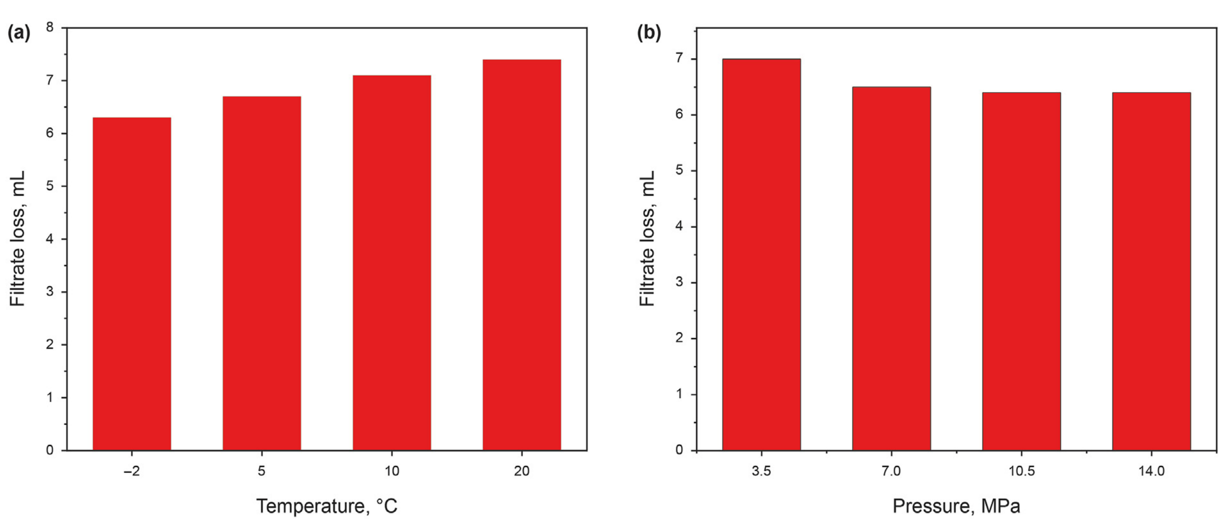

Fig. 13. Fluid loss volume of S7 sample at different temperatures and pressures.

filtrate volume obtained from the experiments. Experimental results indicate that filtrate loss gradually decreases when the BN nanoparticle concentration increases from 0.1 wt% to 0.4 wt%. BN particles are in nano size and may easily disperse in fluid. This dispersed nanoparticles act a plaster in between the particles and seal the permeable formation which effectively reduces the fluid loss (Mirzaei-paiaman. 2009). Therefore, as more and more nanoparticles are added to the sample, more and more nanoparticles act as a plaster to seal the permeable formation thus the filtration is controlled. However, the filtrate volume again starts to increase as the nanoparticle concentration further increases to 0.6 wt% (S8 sample). This might be the results of the agglomeration of BN nanoparticles which behaves similar to larger particles causing higher amount of filtrate loss (Smith et al., 2018). Initially, the filtrate volume was high but it starts to reduce as the solid particles of BN nanoparticles and other additives settle down and form a filter cake (da Silva et al., 2019).

The effect of filtrate loss of drilling fluids at lower temperature has been reported in a few studies. Rojas et al. (2007) reported that the filtrate loss decreases significantly at low temperature of deepwater environment. This is due to an increase in viscosity of the drilling fluid at low temperature. Balavi and Boluk (2018) reported the effect of mud temperature on the total filtrate volume using 3% bentonite and 0.5% starch formulation. They found that the filtrate loss increases with an increase in temperature due to cake erosion.

Filter-cake permeability is another vital parameter which controls the fluid flowing through the filter cake and pore pressure variation around the wellbore. Similar to mud cake porosity, the permeability is also affected by various factors such as porosity and permeability of the formation, drilling fluid properties and differential pressure across the filter cake. Under static filtration condition, the calculated permeability value ranges from 0.16 mD to 0.008 mD as shown in Fig. 15. Similar range of filter-cake permeability was also mentioned by Jaffal et al. (2017). Permeability decreases up to 94% with the addition of BN nanoparticles (for S7 sample) compared to sample without nanoparticles (S1 sample). Results of the filter-cake permeability shows similar pattern as the filtrate volume and filter-cake thickness. Permeability was maximum for the drilling fluid without any nanoparticles but it shows decreasing order as nanoparticles was added to the drilling fluid. The permeability of the filter cake decreased until the concentration of nanoparticles was 0.4 wt%, but starts to increase at 0.6 wt% concentration. Agglomeration of these nanoparticles at 0.6 wt% was responsible for this increasing permeability. Microparticles are positioned between the clay flakes (bentonite) which makes the cake more permeable. Micron sized particles create a network-type structure which consists of small pore space. These pore spaces are being able to be filled with BN nanoparticles, which make the cake more compact and less permeable. From some literature review, it is found that 10^{-4} to 10^{-2} mD is the optimum value of permeability for stable formation. In the present study, the S7 sample shows the permeability (0.0055 mD) near to the desired value. Mahmoud et al. (2016) also mentioned some nanoparticle-based drilling fluid with filter-cake permeability ranging from 0.003 mD to 0.0003 mD.

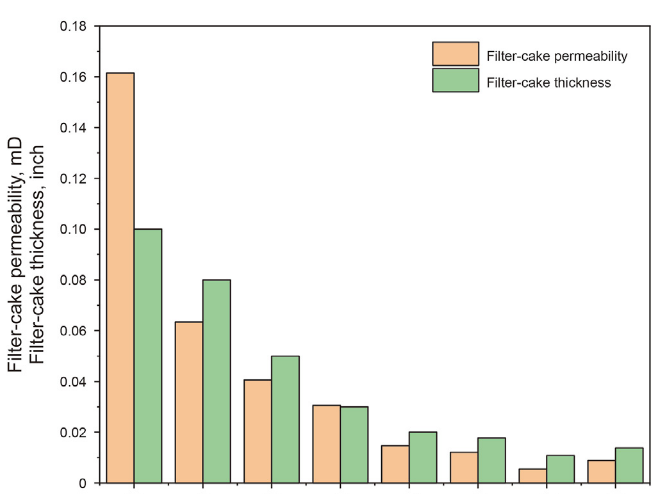

Fig. 15. Effect of different drilling fluids on filter-cake permeability and thickness.

After the completion of the fluid loss test, a measurement of the filter-cake thickness and permeability was investigated which is mentioned in Fig. 15. Thickness of the filter cake was achieved by using a Vernier calliper scale. Filter-cake thickness can be affected by different factors such as pressure differences between formations and wellbore and drilling fluid properties. It is a vital property because the cake that forms on the permeable zone in the wellbore can cause pipe to stuck and other drilling problems. Normally, the filter cake is required to be as thin as possible. Drilling fluid should comprise small particles to generate thin filter cake due to their ability to plug the pore space by depositing in the permeable formation. Thickness of the filter cake was measured after completion of fluid loss test and it is mentioned in Fig. 15. The results reveal similar trend as fluid loss volume. The thickest filter cake (0.1 inch) was produced by drilling fluids without BN nanoparticle (S1 sample) and the thinnest (0.01 inch) was obtained by drilling fluid with 0.4 wt% nanoparticle concentration. It can be signified that, there was a 90% reduction of filter-cake thickness for S7 sample compared to the base fluid (S1). Nanoparticles have the advantage to make a filter cake more continuous and integrated which leads to create low permeable filter cake because of their nano-sized particles. Therefore, there will be low volume of filtrate due to the integrated and low permeable filter cake which leads to lesser filter cake thickness than before (Mirzaei-paiaman 2009). With increasing concentration of nanoparticles, the filter cake becomes more compacted as nanoparticles fills up the empty space between the micro-particles. When the concentration of BN nanoparticles in the drilling fluid gradually rises up to 0.4 wt%, the thickness of the filter cake starts to reduce with reducing permeability. However, at 0.6 wt% concentration, nanoparticles start to agglomerate which leads to an increase in cake permeability and ultimately the thickness of the filter cake also increases. Less than 2/32 inch is considered to be the suitable range of thickness (Mansfield, 1995). A similar range of data was also provided by Jaffal et al. (2017). To increase the effective well diameter and reduce excessive torque and drag, and to avoid the pipe to stuck, the thinner filter cake is usually recommended in drilling operations (Feng and Li, 2018).

The effects of salt and temperature on filtrate loss are also reported in literature. The API filtrate loss of the drilling fluid decreases with increasing concentration of NaCl salt (Quan et al., 2014). The viscosity of the drilling fluid deceases with increasing temperature, which leads to an increasing filtrate loss (Soto et al., 2020).

3.6. Statistical analysis of the effect of bentonite, guar gum and BN nanoparticles on filtrate loss

Modelling of the fluid loss behaviour of nanoparticle-based drilling fluid is very important for drilling when designing and planning for economically effective drilling operation (Vryzas and Kelessidis, 2017). Vryzas and Kelessidis (2017) reported a promising attempt to model the rheological and filtrate loss of nanoparticle-based drilling fluid. One of the most important functions of the drilling fluid is to prevent filtrate from entering the formation. Swelling of clay, migration of particles and water blocking play an important role in preventing the invasion of filtrate into the formation by producing a filter cake which ultimately reduces the permeability of the filter cake (Kerunwa and Anyadiegwu, 2015). Drilling fluid composed of different sized particles helps to create a desirable filter cake. Larger particles help to form the structure of the filter cake whereas smaller particles migrate and fill up the pores in the filter cake formed by larger particles (Blkoor and KA, 2013). The effects of the concentrations of guar gum (X), boron nitride nanoparticles (Y), and bentonite (Z) on the fluid loss behaviour and the filter cake thickness of the drilling fluid were studied. The experimental design is mentioned earlier in Table 1. The products of the experimental studies obtained are mentioned in Figs. 12 and 13.

Depending on the probability value (P values) fixed at the significance level of 5% and the Fischer's ratio (F value), the influence of the individual factors (X, Y, Z) and the interaction between the factors (XY) play a very important role in improving the reduction of filtrate volume (V_f) and filter cake thickness (h_c) of the drilling fluid. The analysis of variance (ANOVA) for fluid loss, filter cake thickness and filter cake permeability are shown in Table 8. The statistical models correlated with the several factors to the cumulative filtrate loss (V_f), filter cake thickness (h_c) and filter cake permeability (k_c) which are mentioned below.

$$V_f = 42.32 - 86.08X - 324.3Y + 804.3XY \quad (R^2 = 0.9967) \tag{4}$$

$$h_c = 0.2073 - 0.2207Y - 0.2762X - 0.00482Z + 0.1705Y^2 \quad (R^2 = 0.9902) \tag{5}$$

$$k_c = 0.03728 - 0.011680V_f + 0.7941h_c + 0.000872V_f^2 \quad (R^2 = 0.9999) \tag{6}$$

ANOVA analysis was used to see the significance and adequacy of the models. The F value is the ratio of the mean square of the model to that of the residual. The higher F value and the lower P value of the factors in a model is the implication of significance of their respective response variable (Li and Fu, 2005). As BN and guar gum are having higher F values and lower P values as shown in Table 6, it can be concluded that these two factors have the maximum effect on fluid loss reduction. In the case of filter-cake thickness, from the regression modelling it is clear that amongst all the factors, boron nitride (BN) has the maximum F value and minimum P value as mentioned in Table 6. Thus, BN has the maximum effect on filter-cake thickness. And for filter-cake permeability, the filter-cake thickness has a greater influence than fluid loss as the F value of thickness is higher and the P value is lower than fluid loss. The coefficient of correlation values for Eqs. (4)–(6) are the indication of well fitted statistical models for the response variables with the experimental data. In the case of fluid loss volume, the value of R^2 (99.67%) implies that factors like bentonite and BN nanoparticles are mostly responsible for fluid loss volume and suggests that 0.33% of the total variation is not accounted by the model. In the case of filter-cake thickness, the total variation of 99.36% can be explained by the statistical model though the model is not able to explain 0.64% of the total variation which attributes to the factors under consideration. The concentrations of guar gum, bentonite and boron nitride nanoparticles are considered to affect the fluid loss and filter cake thickness (response variables) significantly. From the regression equation, it is clear that, the filtrate loss and filter-cake thickness will decrease when terms with positive coefficient increases. A similar condition is also applicable for terms with a negative coefficient, which has to decrease for fluid loss and thickness of the filter cake to decrease. Afolabi et al. (2018) conducted research with similar regression equation. Thus, this regression model was able to capture the influence of bentonite, guar gum and BN nanoparticles to the performance of fluid loss of water-based drilling fluid.

Table 8
Analysis of variance (ANOVA) for regression model.

Source	DF	Adj SS	Adj MS	F value	P value
ANOVA: Filtrate loss (Eq. (4))					
Model	3	76.5279	25.5093	404.79	0.00002
X	1	42.4515	42.4515	673.63	0.00001
Y	1	43.0599	43.0599	683.29	0.00001
XY	1	41.8159	41.8159	663.54	0.00001
Error	4	0.2521	0.0630	-	-
Total	7	76.7800	–	-	-
ANOVA: Filter-cake thickness (Eq. (5))					
Model	4	0.008807	0.002202	76.02	0.002
Y	1	0.000684	0.000684	23.63	0.017
X	1	0.00434	0.00434	15.00	0.030
Z	1	0.000014	0.000014	0.49	0.535
Y^2	1	0.000284	0.000284	9.80	0.052
Error	3	0.000087	0.000029	–	–
Total	7	0.008894	–	–	–
ANOVA: Filter-cake permeability (Eq. (6))					
Model	3	0.019072	0.006357	43530.38	0.00001
V_f	1	0.000028	0.000028	194.33	0.00015
h_c	1	0.000763	0.000763	5223.81	0.000001
V_f^2	1	0.000103	0.000103	706.64	0.00001
Error	4	0.000001	0.00	–	–
Total	7	0.019073	–	–	–

3.7. Filter-cake surface morphology

The surface morphology of the filter cake was investigated by FE-SEM analysis as it delivers high magnification images of the filter cake surface (Zhong et al., 2019). The physical mechanism of reduction of filtration loss after the addition of nanoparticles has been explained by Dejtaradon et al., (2019). The microscopic structure of different filter cake surfaces for different drilling fluid systems were studied using a scanning electron microscope (SEM) and their images are shown in Fig. 16. Filter cake formed from the drilling fluid with the absence of nanoparticles (S1) have very porous and permeable filter cake. Whereas, drilling fluids with the addition of BN nanoparticles appear to have lesser porous and permeable filter cake compared to the drilling fluid without nanoparticles. As the concentration of nanoparticles continues to increase, the filter cake gets smoother and low porous. Smooth and low porous filter cake is desirable due to the significant effect on reduction in fluid loss and filter cake thickness. It is clear that S7 and S8 samples are better capable of controlling fluid loss and strengthening the wall due to the formation of a thin, smooth, less porous and less permeable filter cake. Nanoparticles have the capacity of reducing the filtration loss as well as the pore space and permeability of the filter cake by filling the pore space as observed in Fig. 15. Filter cake formed from the nano-based drilling fluid with 0.4 wt% BN nanoparticles (S7) shows little or no agglomeration. But large amount of agglomerates is visible at 0.6 wt% concentration. BN nanoparticles showing increasing agglomeration have an effect on filtration profile. Smooth and low porous filter cake is required for low fluid loss and minimum of filter cake thickness which is desirable in the drilling industry to avoid formation damage. From the experimental data, it is found that the impact of nanoparticles become much effective with a higher concentration of microparticles.

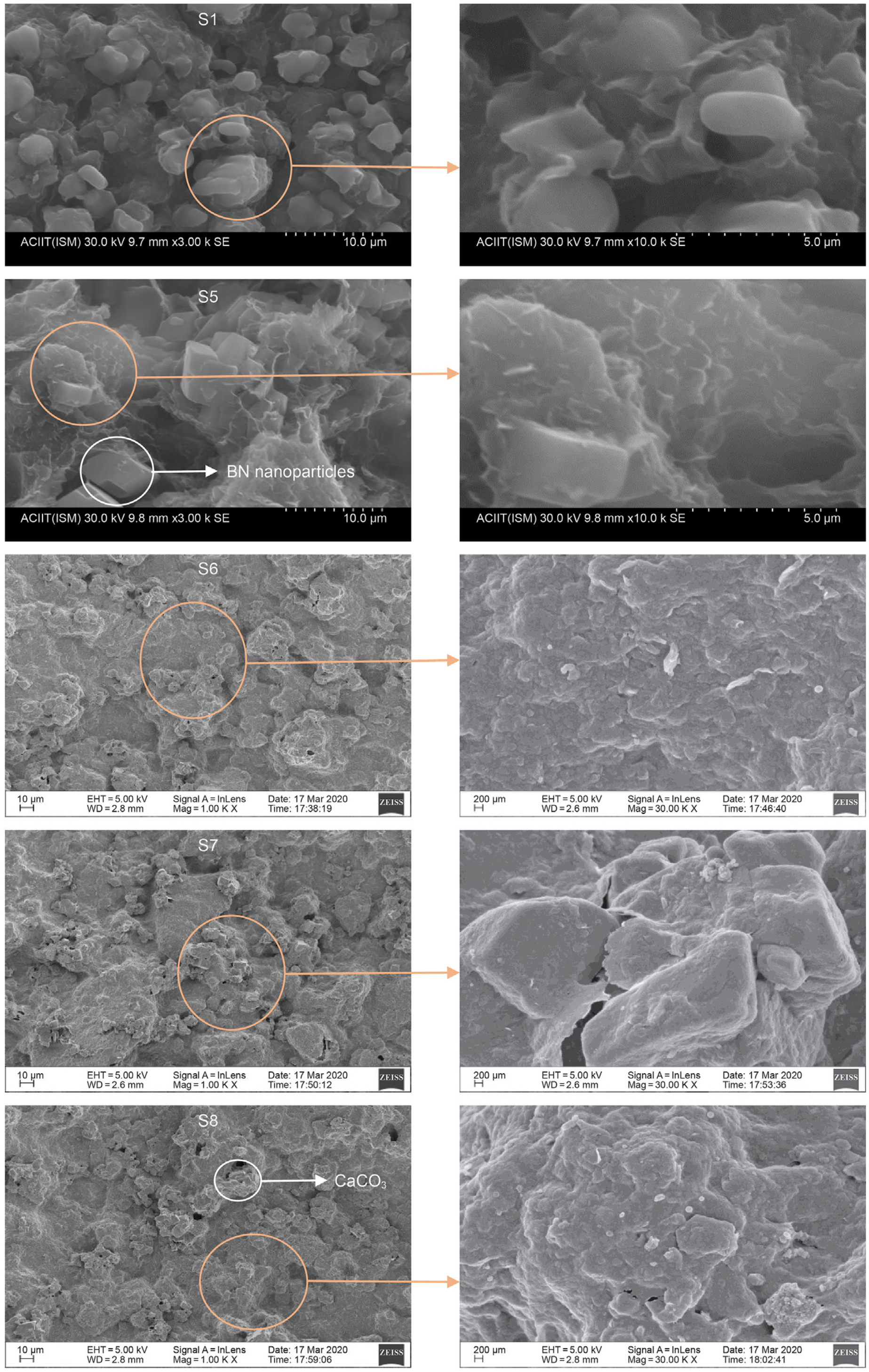

Fig. 16. FE-SEM images of filter-cake morphology of different samples.

4. Conclusions

The beneficial effects of BN nanoparticles to water-based drilling fluid for application in deepwater and hydrate reservoirs were studied by measurement of the rheological properties along with their viscoelastic behaviour and filtration characteristics. Based on the experimental observations the following conclusion may be drawn:

- The BN nanoparticles have the ability to help the drilling fluids to enhance their rheological properties as well as fluid loss control.
- The addition of nanoparticles decreases the viscosity of the samples but further addition of them enhances the viscosity due to different types of intermolecular interaction.
- These nanoparticle-enhanced drilling fluids are capable of reducing filtrate loss. Combination of micron sized bentonite, nanoparticles and guar gum polymer creates dense packing and

dispersed nanoparticles which act a plaster in between the particles and seal the permeable formation which effectively reduces filtrate loss.

- Regression modelling also provides the similar results that nanoparticles and guar gum are responsible for reducing filtrate loss and filter-cake thickness.
- With an increasing amount of BN nanoparticles, the surface of the filter cake becomes smoother with very low pore space as observed from FE-SEM images of filter-cake morphology.

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.

Acknowledgments

We gratefully acknowledge the financial assistance provided by Earth System Science Organization, Ministry of Earth Sciences, Government of India, New Delhi (MoES/36/OOIS/Extra/65/2016) and SERB(DST), New Delhi to the Department of Petroleum Engineering, Indian Institute of Technology (ISM), Dhanbad, India.

References

Adesina, F., Patrick, O., Temitope, O., Adebowale, O., 2017. Formulation and evaluation of synthetic drilling mud for low temperature regions. Covenant J. Eng. Technol. 1 (1), 34–48.

Afolabi, R.O., Orodu, O.D., Seteyeobot, I., 2018. Predictive modelling of the impact of silica nanoparticles on fluid loss of water based drilling mud. Appl. Clay Sci. 151, 37–45. https://doi.org/10.1016/j.clay.2017.09.040.

Ahmad, H.M., Murtaza, M., Al-harthi, M., 2017. Improving the drilling fluid properties using nanoparticles and water-soluble. In: SPE Kingdom of Saudi Arabia Annual Technical Symposium and Exhibition, Dammam, Saudi Arabi. https://doi.org/10.2118/188140-MS.

Alcázar-Vara, L.A., Cortés-Monroy, I.R., 2018. Drilling fluids for deepwater fields: an overview. Recent Insights Petrol. Sci. Eng. https://doi.org/10.5772/intechopen.70093.

Ali, I., Ullah, H., 2017. Performance of conventional drilling fluids and nano based drilling fluids. J. Appl. Emrg. Sci. 7 (1), 12–21. https://doi.org/10.36785/jaes.v7i1.211.

Aluova, A., Oseli, A., Bek, M., Prodan, T., Emri, I., 2019. Effects of pressure on mechanical properties of polymer. Encyclop. Contin. Mech. https://doi.org/10.1007/978-3-662-53605-270-2.

Alvi, A.M., Belayneh, M., Saasen, A., Aadnøy, B.S., 2018. The effect of micro-sized boron nitride BN and iron trioxide Fe_2O_3 nanoparticles on the properties of laboratory bentonite drilling fluid. SPE Norw. One Day Semin. https://doi.org/10.2118/191307-MS.

Arisz, P.W., Lusvardi, K., Hercules, L.L.C., 2006. Water-soluble, low substitution hydroxyethylcellulose, derivatives thereof, process of making, and uses thereof. U.S. Patent Appl. 11/363, 107.

Balavi, H., Boluk, Y., 2018. Dynamic filtration of drilling fluids and fluid loss under axially rotating crossflow filtration. J. Petrol. Sci. Eng. 163, 611–615. https://doi.org/10.1016/j.petrol.2017.12.043.

Benchabane, A., Bekkour, K., 2008. Rheological properties of carboxymethyl cellulose (CMC) solutions. Colloid Polym. Sci. 286 (10), 1173. https://doi.org/10.1007/s00396-008-1882-2.

Benyounes, K., Mellak, A., Benchabane, A., 2010. The effect of carboxymethylcellulose and xanthan on the rheology of bentonite suspensions. Energy Sources, Part A Recover. Util. Environ. Eff. 32 (17), 1634–1643. https://doi.org/10.1080/15567030902842244.

Bera, A., Shah, S., Shah, M., Agarwal, J., Vij, R.K., 2020. Mechanistic study on silica nanoparticles-assisted guar gum polymer flooding for enhanced oil recovery in sandstone reservoirs. Colloid. Surface. Physicochem. Eng. Aspect. 598, 124833. https://doi.org/10.1016/j.colsurfa.2020.124833.

Blkoor, S.O., Ka, F., 2013. The influence of XC-polymer on drilling fluid filter cake properties and formation damage. J. Petrol Environ. Biotechnol. 4 (5). https://doi.org/10.4172/2157-7463.1000157.

Bouville, F., Deville, S., 2014. Dispersion of boron nitride powders in aqueous suspensions with cellulose. J. Am. Ceram. Soc. 97 (2), 394–398. https://doi.org/10.1111/jace.12653.

Briscoe, B.J., Luckham, P.F., Ren, S.R., 1994. The properties of drilling muds at high pressures and high temperatures. Phil. Trans. Roy. Soc. Lond. 348 (1687), 179–207. https://doi.org/10.1098/rsta.1994.0088.

Cameron, C., Baroid, H., 2005. Deepwater drilling fluids—what's new. AADE-05-NTCE-79 1–6.

Cheraghian, G., 2017. Application of nano-particles of clay to improve drilling fluid. Int. J. Nanosci. Nanotechnol. 13 (2), 177–186.

Chu, Q., Lin, L., 2019. Synthesis and properties of an improved agent with restricted viscosity and shearing strength in water-based drilling fluid. J. Petrol. Sci. Eng. 173, 1254–1263. https://doi.org/10.1016/j.petrol.2018.10.074.

Clasen, C., Kulicke, W., 2001. Determination of viscoelastic and rheo-optical material functions of water-soluble cellulose derivatives. Prog. Polym. Sci. 26 (9), 1839–1919. https://doi.org/10.1016/S0079-6700(01)00024-7.

Cooper, L.W., Hook, R.A., Payne, B.R., 1997. Air drilling techniques. In: SPE Deep Drilling and Production Symposium. https://doi.org/10.2118/6435-MS.

da Silva, K.C., de Jesus da Silva, I., Calçada, L.A., Scheid, C.M., 2019. The effect of previous sedimentation on the filtration and mudcake properties of Newtonian and non-Newtonian fluids. Powder Technol. 346, 9–16. https://doi.org/10.1016/j.powtec.2019.01.038.

Dejtaradon, P., Hamidi, H., Chuks, M.H., Wilkinson, D., Rafati, R., 2019. Impact of ZnO and CuO nanoparticles on the rheological and filtration properties of water-based drilling fluid. Colloid. Surface. Physicochem. Eng. Aspect. 570, 354–367. https://doi.org/10.1016/j.colsurfa.2019.03.050.

Feng, Y., Li, X., 2018. Mudcake effects on wellbore stress and fracture initiation pressure and implications for wellbore strengthening. Petrol. Sci. 15 (2), 319–334. https://doi.org/10.1007/s12182-018-0218-1.

Friedheim, J.E., Patel, A., 1999. Technical solutions for environmental problems: novel drilling formulations to minimize environmental impact. In: SPE/EPA Exploration and Production Environmental Conference. https://doi.org/10.2118/52741-MS.

Gamal, H., Elkatatny, S., Basfar, S., Al-Majed, A., 2019. Effect of pH on rheological and filtration properties of water-based drilling fluid based on bentonite. Sustainability 11 (23), 6714. https://doi.org/10.3390/su11236714.

Gerogiorgis, D.I., Reilly, S., 2017. Experimentally validated first-principles multivariate modeling for rheological study and design of complex drilling nanofluid systems. In: SPE/IADC Drilling Conference and Exhibition. https://doi.org/10.2118/184692-MS.

Han, W.Q., 2009. Anisotropic hexagonal boron nitride nanomaterials: synthesis and applications. Nanotechnol. Life Sci. https://doi.org/10.1002/9783527610419.ntls0161.

Hasan, M.L., Abidin, N.A.Z., Singh, A., 2018. The rheological performance of guar gum and castor oil as additives in water-based drilling fluid. Mater. Today: Proceedings 5 (10), 21810–21817. https://doi.org/10.1016/j.matpr.2018.07.036.

Hassiba, K.J., Amani, M., 2012. The effect of salinity on the rheological properties of water based mud under high pressures and high temperatures for drilling offshore and deep wells. Earth Sci. Res. 2 (1), 175–186. https://doi.org/10.5539/esr.v2n1p175.

Herzhaft, B., Rousseau, L., Neau, L., Moan, M., Bossard, F., 2002. Influence of temperature and clays/emulsion microstructure on oil-based mud low shear rate rheology. SPE Ann. Tech. Conf. Exhibit. https://doi.org/10.2118/77818-MS.

Hu, Y., Yue, Q., Liu, S., Fu, Z., Liang, S., 2011. Research on deepwater synthetic drilling fluid and its low temperature rheological properties. Petrol. Sci. 8 (4), 485–489. https://doi.org/10.1007/s12182-011-0165-6.

Iqbal, R., Zubair, M., Pirzada, F., Abro, F., Ali, M., Valasai, A., 2019. An experimental study on the performance of calcium carbonate extracted from eggshells as weighting agent in drilling fluid. Eng. Technol. Appl. Sci. Res. 9 (1), 3859–3862.

Jaffal, H.A., Mohtar, CS El, Gray, K.E., 2017. Modeling of filtration and mudcake buildup: an experimental investigation. J. Nat. Gas Sci. 38, 1–11. https://doi.org/10.1016/j.jngse.2016.12.013.

Jain, R., Mahto, V., 2015. Evaluation of polyacrylamide/clay composite as a potential drilling fluid additive in inhibitive water based drilling fluid system. J. Petrol. Sci. Eng. 133, 612–621. https://doi.org/10.1016/j.petrol.2015.07.009.

James, R.W., Schei, T., Navestad, P., Geddes, T.A., Nelson, M.G., Webster, D., 2000. Improving the working environment and drilling economics through better understanding of oil-based drilling fluid chemistry. SPE Drill. Complet. 15 (4), 254–260. https://doi.org/10.2118/67835-PA.

Jedrzejczak-Silicka, M., Trukawka, M., Dudziak, M., 2018. Hexagonal boron nitride functionalized with Au nanoparticles — properties and potential biological applications. Nanomaterials 8 (8), 605. https://doi.org/10.3390/nano8080605.

Jensen, B., Asa, S., Paulsen, J.E., Asa, S., Saasen, A., Asa, S., Prebensen, O.I., Norge, M.S., Balzer, H., 2004. Application of water based drilling fluid-total fluid management. In: IADC/SPE Drilling Conference. https://doi.org/10.2118/87103-MS.

Karen, J., William, M., Ponmani, S., Samuel, R., Nagarajan, R., Sangwai, J.S., 2014. Effect of CuO and ZnO nano fluids in xanthan gum on thermal, electrical and high pressure rheology of water-based drilling fluids. J. Petrol. Sci. Eng. 117, 15–27. https://doi.org/10.1016/j.petrol.2014.03.005.

Karimi Vajargah, A., van Oort, E., 2015. Determination of drilling fluid rheology under downhole conditions by using real-time distributed pressure data. J. Nat. Gas Sci. Eng. 24, 400–411. https://doi.org/10.1016/j.jngse.2015.04.004.

Katende, A., Boyou, N.V., Ismail, I., Chung, D.Z., Sagala, F., Hussein, N., Ismail, M.S., 2019. Improving the performance of oil based mud and water based mud in a high temperature hole using nanosilica nanoparticles. Colloid. Surface. Physicochem. Eng. Aspect. 577, 645–673. https://doi.org/10.1016/j.colsurfa.2019.05.088.

Kerunwa, A., Anyadiegwu, C.I.C., 2015. Overview of the advances in casing drilling technology. Pet. Coal 57 (6), 661–675.

Kumar, S., Thakur, A., Kumar, N., Husein, M.M., 2020. A novel oil - in - water drilling mud formulated with extracts from Indian mango seed oil. Petrol. Sci. 17 (1), 196–210. https://doi.org/10.1007/s12182-019-00371-7.

Li, Q., Fu, C., 2005. Application of response surface methodology for extraction

optimization of germinant pumpkin seeds protein. Food Chem. 92 (4), 701–706. https://doi.org/10.1016/j.foodchem.2004.08.042.
Li, W., Zhao, X., Ji, Y., Peng, H., Chen, B., Liu, L., Han, X., 2016. Investigation of biodiesel-based drilling fluid, part 2 : formulation design, rheological study, and laboratory evaluation. SPE J. 21 (b), 1767–1781. https://doi.org/10.2118/180926-PA, 05.
Li, W., Zhao, X., Ji, Y., Peng, B., Chen, B., Liu, L., Han, X., 2016a. Investigation of biodiesel-based drilling fluid, Part 1: biodiesel evaluation, invert-emulsion properties, and development of a novel emulsifier package. SPE J. 21 (5), 1755–1766. https://doi.org/10.2118/180918-PA, 2016.
Liang, Z., Chong, Z., Haidong, H., Dongming, Q.I., Yu, Z., Shaoran, R.E.N., 2014. Gas hydrate risks and prevention for deep water drilling and completion: a case study of well QDN-X in Qiongdongnan Basin, South China Sea. Petrol. Explor. Dev. 41 (6), 824–832. https://doi.org/10.1016/S1876-3804(14)60100-2.
Liu, B.C., Liu, S.Q., Chen, Z.R., Meng, Q.N., Li, C., 2016a. Oxide and diamond nanoparticles modified drilling fluid for deep, complicated drilling conditions. J. Nanosci. Nanotechnol. 16 (12), 13007–13013. https://doi.org/10.1166/jnn.2016.13849.
Liu, T., Jiang, G., Zhang, P., Sun, J., Sun, H., Wang, R., Zheng, M., 2016b. A new low-cost drilling fluid for drilling in natural gas hydrate-bearing sediments. J. Nat. Gas Sci. Eng. 33, 934–941. https://doi.org/10.1016/j.jngse.2016.06.017.
Mahasneh, M.A., 2013. Air drilling efficiency in wellbores in disi water field project. Global J. Res. Eng. 13 (1), 27–34.
Mahmoud, O., Nasr-el-din, H.A., Texas, A., Vryzas, Z., Kelessidis, V.C., 2016. Nanoparticle-based drilling fluids for minimizing formation damage in HP/HT applications. In: SPE Int Conf Exhib Formation Damage Control. https://doi.org/10.2118/178949-MS.
Malloy, K.P., Medley, G.H., Stone, C.R., 2007. Taking another look at the risk profile for air drilling in presence of hydrocarbon. Manag. Pressure Drill. 66–73.
Mansfield, C.T., 1995. Petroleum and coal lubricants. Anal. Chem. 67 (12), 333–338. https://doi.org/10.1021/ac00108a603.
Mezger, T.G., 2009. The rheology handbook. Pigment Resin Technol. 38, 790–797. https://doi.org/10.1108/prt.2009.12938eac.006.
Mudgil, D., Barak, S., Khatkar, B.S., 2014. Guar gum: processing, properties and food applications — a review. J. Food Sci. Technol. 51 (3), 409–418. https://doi.org/10.1007/s13197-011-0522-x.
Navarrete, R.C., Himes, R.E., Seheult, J.M., 2000. Applications of xanthan gum in fluid-loss control and related formation damage. In: SPE Permian Basin Oil and Gas Recovery Conference. https://doi.org/10.2118/59535-MS.
Odziomek, M., Kalinowska, M., Płuzińska, A., Rożeń, A., Sosnowski, T.R., 2017. Ronchial mucus as a complex fluid: molecular interactions and influence of nanostructured. Chem. Process Eng. 38 (2), 217–229. https://doi.org/10.1515/cpe-2017-0017.
Ofei, T., 2016. Effect of yield power law fluid rheological properties on cuttings transport in eccentric horizontal narrow annulus. J. Fluids 1–10. https://doi.org/10.1155/2016/4931426.
Ozbayoglu, E.M., 2008. Effect of pipe rotation on hole cleaning for water-based drilling fluids in horizontal and deviated wells. In: IADC/SPE Asia Pacific Drilling Technology Conference and Exhibition, Jakarta, Indonesia. https://doi.org/10.2118/114965-MS.
Paiaman, A.M., Al-Anazi, B.D., 2009. Feasibility of decreasing pipe sticking probability using nanoparticles. Nafta 60 (12), 645–647.
Pakdaman, E., Osfouri, S., Azin, R., Niknam, K., Roohi, A., 2019. Improving the rheology, lubricity, and differential sticking properties of water-based drilling muds at high temperatures using hydrophilic Gilsonite nanoparticles. Colloid. Surface. Physicochem. Eng. Aspect. 582, 123930.
Perween, S., Beg, M., Shankar, R., Sharma, S., Ranjan, A., 2018. Effect of zinc titanate nanoparticles on rheological and filtration properties of water based drilling fluids. J. Petrol. Sci. Eng. 170, 844–857. https://doi.org/10.1016/j.petrol.2018.07.006.
Quan, H., Li, H., Huang, Z., Zhang, T., Dai, S., 2014. Copolymer SJ-1 as a fluid loss additive for drilling fluid with high content of salt and calcium. Int. J. Poly. Sci. https://doi.org/10.1155/2014/201301.
Razi, M.M., Ghiass, M., Razi, F.M., 2013. Effect of guar gum polymer and lime powder addition on the fluid loss and rheological properties of the bentonite dispersions. J. Dispersion Sci. Technol. 34 (5), 731–736. https://doi.org/10.1080/01932691.2012.683985.
Rodriguez, K., Araujo, M., 2006. Temperature and pressure effects on zeta potential values of reservoir minerals. J. Colloid Interface Sci. 300 (2), 788–794. https://doi.org/10.1016/j.jcis.2006.04.030.
Rojas, J.C., Daugherty, W.T., Irby, R.D., Bern, P.A., Romo, L.A., Dye, W.M., Greene, B., Trotter, R.N., 2007. New constant-rheology synthetic-based fluid reduces downhole losses in deepwater environments. In: SPE Annual Technol Conf Exhibit. https://doi.org/10.2118/109586-MS.
Sadeghalvaad, M., Sabbaghi, S., 2015. The effect of the TiO_2/polyacrylamide nanocomposite on water-based drilling fluid properties. Powder Technol. 272, 113–119. https://doi.org/10.1016/j.powtec.2014.11.032.
Sloan, D., Koh, C., 2000. Clathrate hydrates of natural gases. Energy Fuels 14, 1123–1124. https://doi.org/10.1021/ef000056e.
Smith, S.R., Rafati, R., Haddad, A.S., Cooper, A., Hamidi, H., 2018. Application of aluminium oxide nanoparticles to enhance rheological and filtration properties of water based muds at HPHT conditions. Colloid. Surface. Physicochem. Eng. Aspect. 537, 361–371. https://doi.org/10.1016/j.colsurfa.2017.10.050.
Song, K., Wu, Q., Li, M., Dong, L., Zhang, X., Lei, T., Kojima, Y., 2016. Water-based bentonite drilling fluids modified by novel biopolymer for minimizing fluid loss and formation damage. Colloid. Surface. Physicochem. Eng. Aspect. 507, 58–66. https://doi.org/10.1016/j.colsurfa.2016.07.092.
Soto, D., León, O., Urdaneta, J., Muñoz-Bonilla, A., Fernández-García, M., 2020. Modified starch as a filter controller in water-based drilling fluids. Materials 13 (12), 2794, 10.3390%2Fma13122794.
Srungavarapu, M., Patidar, K.K., Pathak, A.K., Mandal, A., 2018. Performance studies of water-based drilling fluid for drilling through hydrate bearing sediments. Appl. Clay Sci. 152, 211–220. https://doi.org/10.1016/j.clay.2017.11.014.
Strømø, S.M., Belayneh, M., 2017. Drilling fluid formulation and characterization. Int. J. Fluid Eng. 9 (1), 21–29.
Tran, T., Van Usta, A., Asmatulu, R., 2016. Functionalized hexagonal boron nitride nanocoatings for protection of transparent plastics. Int. Soc. Opt. Photon. 9799. https://doi.org/10.1117/12.2235331.
van Oort, E., Lee, J., Friedheim, J., Toups, B., 2004. New flat-rheology synthetic - based mud for improved deepwater drilling. In: SPE Annual Technol Conf Exhibit. https://doi.org/10.2118/90987-MS.
Venditti, R., 2014. Temperature effects on the zeta potential. In: Encyclopedia of Microfluidics and Nanofluidics. Springer. https://doi.org/10.1007/978-3-642-27758-0_1532-2.
Vryzas, Z., Kelessidis, V.C., 2017. Nano-based drilling fluids: a review. Energies 10 (4), 540. https://doi.org/10.3390/en10040540.
Wang, H., 2006. Preparation and morphology of SiO_2/PMMA nanohybrids by microemulsion polymerization. Colloid Polym. Sci. 284 (7), 755–762. https://doi.org/10.1007/s00396-005-1428-9.
Wang, X., Yu, J., Sun, Y., Yang, C., Jiang, L., Liu, C., 2018. A solids-free brine drilling fluid system for coiled tubing drilling. Petrol. Explor. Dev. 45 (3), 529–535. https://doi.org/10.11698/PED.2018.03.16.
Wegner, M.R., Webb, T., Maharaj, M.A., Twynam, A.J., Green, T.C., Salamat, G., 2006. Horizontal drilling and openhole gravel-packing with oil-based fluids-An industry milestone. SPE Drill. Complet. 21 (1), 32–43. https://doi.org/10.2118/87648-PA.
Werner, B., Myrseth, V., Saasen, A., 2017. Viscoelastic properties of drilling fluids and their influence on cuttings transport. J. Petrol. Sci. Eng. 156, 845–851.
Xie, B., Ting, L., Zhang, Y., Liu, C., 2018. Rheological properties of bentonite-free water-based drilling fluids with novel polymer viscosifier. J. Petrol. Sci. Eng. 164, 302–310. https://doi.org/10.1016/j.petrol.2018.01.074.
Yao, R., Jiang, G., Li, W., Deng, T., Zhang, H., 2014. Effect of water-based drilling fluid components on filter cake structure. Powder Technol. 262, 51–61. https://doi.org/10.1016/j.powtec.2014.04.060.
Young, S., Friedheim, J., Lee, J., Prebensen, O.I., 2012. A new generation of flat rheology invert drilling fluids. In: SPE Oil Gas India Conf. Exhib. https://doi.org/10.2118/154682-MS.
Zakaria, M.F., Husein, M., Hareland, G., 2012. Novel nanoparticle-based drilling fluid with improved characteristics. In: SPE International Oilfield Nanotechnology Conference and Exhibition. https://doi.org/10.2118/156992-MS.
Zhao, X., Qiu, Z., Huang, W., 2015a. Characterization of kinetics of hydrate formation in the presence of kinetic hydrate inhibitors during deepwater drilling. J. Nat. Gas Sci. Eng. 22, 270–278. https://doi.org/10.1016/j.jngse.2014.12.006.
Zhao, X., Qiu, Z., Zhou, G., Huang, W., 2015b. Synergism of thermodynamic hydrate inhibitors on the performance of poly (vinyl pyrrolidone) in deepwater drilling fluid. J. Nat. Gas Sci. Eng. 23, 47–54. https://doi.org/10.1016/j.jngse.2014.12.031.
Zhao, X., Qiu, Z., Huang, W., Wang, M., 2017. Mechanism and method for controlling low-temperature rheology of water-based drilling fluids in deepwater drilling. J. Petrol. Sci. Eng. 154, 405–416. https://doi.org/10.1016/j.petrol.2017.04.036.
Zhao, X., Qiu, Z., Zhao, C., Xu, J., Zhang, Y., 2019. Inhibitory effect of water-based drilling fluid on methane hydrate dissociation. Chem. Eng. Sci. 199, 113–122. https://doi.org/10.1016/j.ces.2018.12.057.
Zhong, H., Shen, G., Qiu, Z., Lin, Y., Fan, L., Xing, X., 2019. Minimizing the HTHP filtration loss of oil-based drilling fluid with swellable polymer microspheres. J. Petrol. Sci. Eng. 172, 411–424. https://doi.org/10.1016/j.petrol.2018.09.074.
Żyła, G., Witek, A., Gizowska, M., 2015. Rheological profile of boron nitride–ethylene glycol nanofluids. Journal of Applied Physics 117 (1), 014302. https://doi.org/10.1063/1.4903737.