



## Article

# Water-based drilling fluid with palygorskite: cutting carrying and contaminants

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### Abstract

In the petroleum industry, one of the most important functions fluids must perform is to carry cuttings efficiently. In this context, the contamination of drilling fluids represents a challenge to the industry because it alters the properties of these fluids. This work compares two drilling fluids (one palygorskite-based and the other polymer-based), evaluating the effects of contaminants on these drilling fluids and their ability to carry cuttings. A contaminant is considered to be any material that causes undesirable changes in the properties of the drilling fluid. Contamination of an aqueous drilling fluid by calcium hydroxide ( $\text{Ca}(\text{OH})_2$ ) and brine can increase the filtrate volume, decrease the perforation rate and alter the rheological properties of the fluid. This work analyses the effects of contamination by  $\text{Ca}(\text{OH})_2$  and brine on the properties of salted water-based drilling fluids viscosified with palygorskite. For comparison, tests were performed with a polymeric drilling fluid. The cutting-carrying capacity of these fluids was verified using the empirical correlations of Moore (1974), Chien (1994) and Walker & Mayes (1975). The results show that the drilling fluid with palygorskite is resistant to contamination with  $\text{Ca}(\text{OH})_2$  and brine, presenting low filtrate volume values. The drilling fluid with palygorskite presented greater slip velocities than the polymeric drilling fluid. Regarding the cutting-carrying capacity, the drilling fluid with palygorskite presented positive transport ratio values ( $>0$ ), making it suitable for carrying rock cuttings. However, the polymeric drilling fluid showed better performance in terms of cutting-carrying capacity.

**Keywords:** Contaminant, drilling fluid, palygorskite, rock cut

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Drilling fluids are of great importance in well drilling because they are responsible for maintaining the stability of the well, carrying rock cuttings to the surface, keeping rock cuttings in suspension and, by being inert, not damaging the reservoir rock (Bourgoyne Jr *et al.*, 1991).

Viscosifiers have the function of increasing the viscosity of the drilling fluid to improve well cleaning and rock-cutting suspension. Among the viscosifiers used in drilling fluid are polymers and clay minerals (Hughes *et al.*, 1993; Christidis *et al.*, 2010; Chemedá *et al.*, 2013; Dino & Thompson, 2013; Caenn *et al.*, 2016; Zhang *et al.*, 2016). With the use of viscosifiers, it is possible to increase apparent and plastic viscosities and decrease filtrate volume (FV). Carboxymethylcellulose (CMC) is an example of a polymer that has the ability to improve viscosity and decrease FVs (Fagundes *et al.*, 2018).

The clay minerals kaolinite, smectite, palygorskite (Plg) and sepiolite are among the world's most important and useful industrial minerals (Murray, 2000; Zhang *et al.*, 2020). Plg is a clay mineral that can be used as a viscosifier in salted water-based drilling fluids because its rheological properties depend on mechanical interference among long ribbons, overcoming any

electrostatic interactions among particles (Caenn *et al.*, 2016). In the literature, a number of works have characterized Plg for use as a viscosity enhancer in water-based drilling fluids (Neaman & Singer, 2004; Baltar *et al.*, 2009; Santanna *et al.*, 2020). Some works have also reported the organophilization of Plg for application as a viscosity enhancer in oil-based drilling fluids (Zhuang *et al.*, 2017a, 2017b; Silva *et al.*, 2021, 2023).

During well drilling, the contamination of drilling fluid represents a major problem. This type of contamination can be caused by drilling solids, anhydrite/gypsum, cement, salt formations/salt-water flows, carbonates and bicarbonates and hydrogen sulfide (Trotter *et al.*, 2015). Portland cement is made up of the four major clinker minerals: tricalcium silicate (C3S), dicalcium silicate (C2S), tricalcium aluminate (C3A) and tetracalcium aluminoferrite (C4AF; Broni-Bediako *et al.*, 2015). The hydration of silicates releases calcium hydroxide ( $\text{Ca}(\text{OH})_2$ ), which, when solubilized in water, leads to an ionic dissociation, releasing hydroxyl ions ( $\text{OH}^-$ ; Jardiolin *et al.*, 2015). To check for contamination in the fluid by  $\text{Ca}(\text{OH})_2$ , it is necessary to measure the phenolphthalein alkalinity of the filtrate ( $P_f$ ) and the phenolphthalein alkalinity of the drilling fluid ( $P_m$ ; Darley & Gray, 1988). The contamination of drilling mud with salts can derive from a formation water influx or during the drilling of salt beds (Darley & Gray, 1988). This contamination can cause flocculation and even the formation of aggregation structures from the drilling fluid's clay minerals. As a result, changes to drilling fluid properties such as its density,

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rheology and filtration cause several operational issues, including circulation and frictional loss, wellbore swelling, formation collapse and pipe sticking (Li *et al.*, 2020).

An important property of the drilling fluid is the cutting-carrying capacity, obtained from the transport ratio (Elgaddafi *et al.*, 2012; Muherei, 2016; Agwu *et al.*, 2018; Epelle & Gerogiorgis, 2019; Sun *et al.*, 2020; Abbas, 2021). Among the correlations used to evaluate cutting-carrying capacity, the procedure proposed by Moore (1974) presented the smallest average error. Skalle *et al.* (1999) has pointed out that the correlations of Chien (1994) and Walker & Mayes (1975) are also valuable in the petroleum industry.

In the literature, numerous studies are limited to investigating the influence of the physical chemistry properties of Plgs on the rheology of water-based drilling fluid. This present study innovates by verifying the cutting-carrying capacity and the effects of contaminants on the properties of a water-based drilling fluid with Plg and comparing them with a polymeric drilling fluid used within the petroleum industry.

## Materials and methods

### Materials

The preparation of drilling fluids used xanthan gum (XG;  $4.2 \times 10^5 \text{ g mol}^{-1}$ ), sodium CMC ( $3.0 \times 10^5 \text{ g mol}^{-1}$ ), hydroxypropylamine, anionic polycellulose, a cationic polymer, triazine, magnesium oxide (MgO) and a lubricant donated by Petrobras. Sodium chloride (NaCl), potassium chloride (KCl) and Ca(OH)<sub>2</sub> were purchased from Synth, and calcium carbonate (CaCO<sub>3</sub>) was purchased from Dinâmica. The Plg used came from the São Pedro mines in the state of Piauí (Brazil). All products were used without any prior purification.

### Characterization of Plg

The chemical composition of Plg includes silica, alumina and hematite as the main constituents. It also has a low concentration of calcium oxide (Silva *et al.*, 2021). The mineralogical composition and thermogravimetric analyses of Plg can be seen in the work of Silva *et al.* (2021). The morphology and surface charge of Plg from the São Pedro mines were given by Baltar *et al.* (2009), where the samples show a large number of particles of acicular habit and isoelectric points at pH 3.3. Plg also has a specific area of  $\sim 113 \text{ m}^2 \text{ g}^{-1}$  (Araújo *et al.*, 2020).

### Preparation of drilling fluid

Drilling fluids viscosified with Plg (Plg fluid) and polymers (XG and CMC) contaminated with Ca(OH)<sub>2</sub> and brine were formulated. Plg was used at a concentration of  $17.5 \text{ g } 350 \text{ mL}^{-1}$  to prepare the water-based drilling fluid, as defined by Baltar *et al.* (2009) and Santanna *et al.* (2020). In the water-based drilling fluid with polymers, XG and CMC were used at concentrations of 1.5 and  $2.0 \text{ g } 350 \text{ mL}^{-1}$ , respectively. These polymer concentrations are used often in the oil industry (Soares *et al.*, 2020; Borges *et al.*, 2021). The fluids were contaminated with  $0.5 \text{ g } 350 \text{ mL}^{-1}$  Ca(OH)<sub>2</sub> and with 10% brine ( $71 \text{ g L}^{-1}$  NaCl and  $40 \text{ g L}^{-1}$  KCl solution). Low concentrations of contaminants were used, as there is limited literature addressing the action of contaminants, especially in fluids with Plg. The compositions of the fluids studied are shown in Tables 1 and 2.

**Table 1.** Composition of the salted water-based drilling fluid with Plg (Plg fluid).

Component	Function	Concentration (g 350 mL <sup>-1</sup> )
Fresh water	Dispersing medium	323 mL
Plg	Viscosity enhancer	17.5
Hydroxypropylamine	Filtrate reducer	8.0
Anionic polycellulose	Filtrate reducer	3.0
Sodium chloride	Clay inhibitor	12.0
Cationic polymer	Clay inhibitor	6.0
Triazine	Bactericide	0.3
Magnesium oxide	Alkalizing agent	0.5
Calcium carbonate	Sealing material	15.0
Lubricant	Protect the structure of blowout preventers	0.5

A Hamilton Beach stirrer (Fann, TX, USA) was used to prepare all fluids (API Specification 13A, 2010). After adding each component, as listed in Tables 1 and 2, the fluid was stirred at 17,000 rpm for 10 min. Then, each fluid was aged in a Fann Roller oven (model 704ES) for 16 h at 180°C. After ageing, the properties of each fluid were measured, and, prior to each characterization, the fluid was stirred again at 17,000 rpm for 10 min.

### Characterization of the drilling fluid

Following API Recommended Practice 13B-1 (2009), the drilling fluid samples were prepared and their parameters measured following previously established specifications and standard procedures (API Specification 13A, 2010). Apparent viscosity ( $\mu_a$ ), plastic viscosity ( $\mu_p$ ), yield point (YP) and gel strength (GS) were measured with a rotational Ofite viscosimeter (model 800) and calculated according to Equations 1–4, following API Recommended Practice 13B-1 (2009):

$$\mu_a(\text{cP}) = L_{600}/2 \quad (1)$$

$$\mu_p(\text{cP}) = L_{600} - L_{300} \quad (2)$$

where  $L_{600}$  = dial reading at 600 rpm of the rotational viscometer and  $L_{300}$  = dial reading at 300 rpm of the rotational viscometer.

$$\text{YP}(\text{lbf } 100 \text{ ft}^{-2}) = L_{300} - \mu_p \quad (3)$$

**Table 2.** Composition of the salted water-based drilling fluid with polymers (polymeric fluid).

Component	Function	Concentration (g 350 mL <sup>-1</sup> )
Fresh water	Dispersing medium	323 mL
Xanthan gum	Viscosity enhancer	1.5
CMC	Viscosity enhancer and filtrate reducer	2.0
Hydroxypropylamine	Filtrate reducer	8.0
Anionic polycellulose	Filtrate reducer	3.0
Sodium chloride	Clay inhibitor	12.0
Cationic polymer	Clay inhibitor	6.0
Triazine	Bactericide	0.3
Magnesium oxide	Alkalizing agent	0.5
Calcium carbonate	Sealing material	15.0
Lubricant	Protect the structure of blowout preventers	0.5

$$GS(\text{lbf } 100 \text{ ft}^{-2}) = G_{\text{final}} - G_{\text{initial}} \tag{4}$$

where lbf is pounds of force,  $G_{\text{initial}}$  is the initial GS after 10 s of suspension not under shear, obtained from the initial dial reading of the rotating viscometer at 3 rpm after 10 s of suspension and  $G_{\text{final}}$  is the final GS after 10 min of suspension not under shear, obtained from the final dial reading of the rotating viscometer at 3 rpm after 10 min of suspension. GS refers to the strength of shear thixotropy or shear thinning of the drilling fluid at a low shear rate.

The pH of each sample was determined initially by means of a commonly used digital pH meter. The densities of all fluids were determined on a Halliburton Service pressurized densimetric balance. An Ofite API press filter was used to measure fluid FV. A pressure of 100 psi was applied and the test period began at the time of pressure application. At the end of 30 min, the volume of filtrate collected was measured. All experiments were performed at room temperature (~25°C).

Alkalinity and salinity tests were performed using titration. The  $P_f$  and  $P_m$  values were determined using 0.02 N sulfuric acid ( $\text{H}_2\text{SO}_4$ ; purchased from Dinâmica) as a titrant.  $P_f$  represents the number of millilitres of 0.02 N acid required per millilitre of filtrate.  $P_m$  is the number of millilitres of 0.02 N acid required per millilitre of drilling fluid. Fluid salinity was obtained using 0.282 N silver nitrate ( $\text{AgNO}_3$ ; purchased from Vetec) as a titrant. The NaCl concentration of the filtrate ( $\text{mg L}^{-1}$ ) was calculated according to Equation 5:

$$\text{NaCl}(\text{mg L}^{-1}) = 1.65 \times 10,000 \times V_{\text{sn}} \tag{5}$$

where  $V_{\text{sn}}$  is the volume of 0.282 N silver nitrate solution (mL).

**Cutting transport ratio**

The correlations of Moore (1974), Chien (1994) and Walker & Mayes (1975) have also been used for characterizing particle slip velocity (Jafarifar *et al.*, 2020). In the correlations of Moore (1974) and Chien (1994), particles are considered as spheres. The particle’s Reynolds number ( $N_{\text{Re}}$ ) is calculated as a function of apparent viscosity, as described mathematically in Equation 6:

$$N_{\text{Re}} = \frac{928 \times \rho_f \times v_{\text{sl}} \times d_s}{\mu_a} \tag{6}$$

where  $\rho_f$  = density of drilling fluid ( $\text{lb gal}^{-1}$ ),  $v_{\text{sl}}$  = cutting slip velocity ( $\text{ft s}^{-1}$ ),  $d_s$  = cutting diameter (in) and  $\mu_a$  = apparent viscosity (cP).

In Moore’s correlation (Bourgoyne Jr *et al.*, 1991) the apparent viscosity is calculated considering that the fluid presents power-law behaviour, as per Equation 7:

$$\mu_a = \frac{K}{144} \left( \frac{d_2 - d_1}{v_a} \right)^{1-n} \left( \frac{2 + 1/n}{0.0208} \right)^n \tag{7}$$

where  $v_a$  = annular fluid velocity ( $\text{ft s}^{-1}$ ),  $d_2$  = outside diameter of the inner pipe (in) and  $d_1$  = inside diameter of the outer pipe (in). The values of  $K$  (consistency index,  $\text{mPa s}^{-n}$ ) and  $n$  (flow-

behaviour index) are obtained from Equations 8 and 9:

$$n = 3.32 \log \left( \frac{L_{600}}{L_{300}} \right) \tag{8}$$

$$K = \frac{510L_{300}}{511^n} \tag{9}$$

For  $N_{\text{Re}} > 300$ , the flow around the particle is fully turbulent and the particle slip velocity can be described by Equation 10 (Bourgoyne Jr *et al.*, 1991):

$$v_{\text{sl}} = 1.54 \sqrt{d_s \frac{(\rho_s - \rho_f)}{\rho_f}} \tag{10}$$

where  $\rho_s$  = density of cutting ( $\text{lb gal}^{-1}$ ).

For  $N_{\text{Re}} \leq 3$ , the flow is considered to be laminar and the particle slip velocity can be described by Equation 11:

$$v_{\text{sl}} = 82.87 \frac{d_s^2}{\mu_a} (\rho_s - \rho_f) \tag{11}$$

For transitional flow ( $3 < N_{\text{Re}} < 300$ ), the particle slip velocity can be obtained using Equation 12:

$$v_{\text{sl}} = \frac{2.9d_s(\rho_s - \rho_f)^{0.667}}{\rho_f^{0.333} \mu_a^{0.333}} \tag{12}$$

Bourgoyne Jr *et al.* (1991) recommended computing apparent viscosity using Equation 13 for polymer-based drilling fluids using Chien’s (1994) correlation:

$$\mu_a = \mu_p + 5 \frac{\tau_s d_s}{v_a} \tag{13}$$

where  $\mu_p$  = plastic viscosity (cP) and  $\tau_s$  = shear stress ( $\text{lbf } 100 \text{ ft}^{-2}$ ).

According to Bourgoyne Jr *et al.* (1991), Chien’s (1994) correlation is similar to Moore’s (1974) in that it obtains the apparent viscosity of non-Newtonian fluids for use in  $N_{\text{Re}}$ . For clay suspensions, it is recommended to use plastic viscosity ( $\mu_p$ ) as the apparent viscosity (Bourgoyne Jr *et al.*, 1991). Under these conditions, the apparent viscosity is obtained using Equation 14 (Bourgoyne Jr *et al.*, 1991):

$$\mu_a = \mu_p = L_{600} - L_{300} \tag{14}$$

The slip velocity for Chien’s (1994) correlation to  $N_{\text{Re}} < 100$  (transitional flow) is given by Equation 15 (Bourgoyne Jr *et al.*, 1991):

$$v_{\text{sl}} = 0.0075 \left( \frac{\mu_a}{\rho_f d_s} \right) \left[ \sqrt{\frac{36800d_s}{\left( \frac{\mu_a}{\rho_f d_s} \right)^2 \left( \frac{\rho_s - \rho_f}{\rho_f} \right) + 1} - 1} \right] \tag{15}$$

In the correlation of Walker & Mayes (1975), according to Bourgoyne Jr *et al.* (1991), the particle is considered a circular disc in flat fall (i.e. falling flat side down, which represents the condition of the greatest terminal settling velocity). For the

**Table 3.** Properties of the fluids studied (contaminated and non-contaminated).

Property	Plg fluid	Polymeric fluid	Plg 0.5 lb/bbl Ca(OH) <sub>2</sub>	Polymeric 0.5 lb/bbl Ca(OH) <sub>2</sub>	Plg fluid 10% brine	Polymeric fluid 10% brine
μ <sub>a</sub> (cP)	21.0	58.0	18.5	36.5	14.0	45.5
μ <sub>p</sub> (cP)	18	35	15	23	11	31
YP (lbf 100 ft <sup>-2</sup> )	6	46	7	27	6	29
FV (mL)	3.8	5.1	3.2	11.4	2.9	9.3
GS (lbf 100 ft <sup>-2</sup> )	0.0	2.0	0.0	0.5	0.0	0.5
P <sub>m</sub>	1.8	2.5	2.5	2.8	-	-
P <sub>f</sub>	0.1	0.7	0.3	0.4	-	-
pH	8.5	9.4	9.3	10.1	8.8	9.3
Cl <sup>-</sup> (mg L <sup>-1</sup> )	25 000	19 000	-	-	29 000	21 000

bbl = oilfield barrel (1 bbl = 0.159 m<sup>3</sup>).

calculation of apparent viscosity one needs to obtain the shear stress (τ<sub>s</sub>) and shear rate (γ<sub>s</sub>) according to Equations 16 and 17:

$$\tau_s = 7.9\sqrt{h(\rho_s - \rho_f)} = 1.067\theta \quad (16)$$

$$\gamma_s = 1.703N \quad (17)$$

where  $h$  = thickness of the disk (in),  $\theta$  = dial reading,  $\gamma_s$  = shear rate (s<sup>-1</sup>) and  $N$  = rotor speed (rpm).

Thus, calculating the apparent viscosity is done according to Equation 18:

$$\mu_a = 479(\tau_s/\gamma_s) \quad (18)$$

For  $N_{Re} > 100$ , the flow is turbulent and the particle slip velocity is given by Equation 19 (Bourgoyne Jr *et al.*, 1991):

$$v_{sl} = 2.19\sqrt{h\frac{(\rho_s - \rho_f)}{\rho_f}} \quad (19)$$

For  $N_{Re} < 100$ , transitional flow is given by Equation 20 (Bourgoyne Jr *et al.*, 1991):

$$v_{sl} = 0.0203\tau_s\sqrt{\frac{(d_s\gamma_s)}{\sqrt{\rho_f}}} \quad (20)$$

Equation 21 shows the transport velocity (Bourgoyne Jr *et al.*, 1991). The rock cutting advances towards the surface when there is a difference between the annular fluid and particle slip velocities:

$$v_T = v_a - v_{sl} \quad (21)$$

where  $v_T$  = transport velocity (ft s<sup>-1</sup>).

According to Bourgoyne Jr *et al.* (1991), the cutting transport ratio ( $F_T$ ) is an excellent measure of the carrying capacity of a

drilling fluid, and it is determined by dividing the transport velocity by the annular velocity as per Equation 22:

$$F_T = \frac{v_T}{v_a} = 1 - \left(\frac{v_{sl}}{v_a}\right) \quad (22)$$

## Results and discussion

### Properties of fluids

The results of the drilling-fluid properties analysed are given in Table 3.

Silva *et al.* (2013) stated that, according to Petrobras standard EP-1EP-00011-A/2011, clay suspensions must present apparent viscosity (μ<sub>a</sub>) greater than the minimum specified apparent viscosity of 15.0 cP, plastic viscosity (μ<sub>p</sub>) cannot be <4.0 cP and FV cannot be >18.0 mL. Based on this, together with the results shown in Table 3, we observe that only the Plg drilling fluid contaminated with 10% brine does not have adequate apparent viscosity, and this fluid will not carry out adequate cleaning in a drilling well. The salts compete with the polymer for hydration by water; without sufficient water the polymer cannot hydrate and the fluid becomes less viscous. In the case of Plg, according to Santanna *et al.* (2020), when the salt concentration increases, there are insufficient Plg channels available for interaction with sodium cations, and so μ<sub>a</sub> does not increase. Therefore, the use of a greater concentration of Plg could make the fluid more resistant to salt contamination and so maintain the high apparent viscosity, as seen in Santanna *et al.* (2020).

Analysing the polymeric drilling fluid, one can verify that contamination with Ca(OH)<sub>2</sub> causes significant changes to the properties of this fluid. This is because the behaviour of the polymer is different from that presented by the clay mineral. In the presence of Ca(OH)<sub>2</sub>, the polymeric drilling fluid viscosity decreases as the pH increases, probably due to greater ionization of the carboxylate group and interaction with cations. Thus, after obtaining a greater FV value, it is believed that the high alkalization of the media ionized the polymers significantly and affected the organization of the filter cake, increasing its permeability

**Table 4.** Mean values of the rheological parameters of the drilling fluids (standard deviations are given in parentheses).

Fluid	L <sub>600</sub> (θ)	L <sub>300</sub> (θ)	μ <sub>a</sub> Moore (1974) (cP)	μ <sub>a</sub> Chien (1994) (cP)	μ <sub>a</sub> Walker & Mayes (1975) (cP)	μ <sub>p</sub> (cP)	K (mPa s <sup>-n</sup> )	n
Polymeric	116	81	266.61 (11.26)	89.02 (1.41)	323.66 (0.00)	35 (1.41)	1635.13 (179.50)	0.52 (0.02)
Plg	42	24	38.89 (4.71)	18.00 (1.41)	21.57 (0.00)	18 (1.41)	79.87 (24.43)	0.81 (0.05)

**Table 5.** Data used for the calculations of the empirical correlations.

$\rho_f$ (lb gal <sup>-1</sup> ) polymeric fluid	$\rho_f$ (lb gal <sup>-1</sup> ) Plg fluid	$\rho_s$ (lb gal <sup>-1</sup> )	$v_a$ (ft s <sup>-1</sup> )	$d_1$ (in)	$d_2$ (in)	$d_s$ (in)
10	9	21.6	2	5	10	0.25

Note: Equivalences in SI: lb gal<sup>-1</sup> = 0.1 g cm<sup>-3</sup>; ft s<sup>-1</sup> = 30.48 cm s<sup>-1</sup>; 1 in = 2.54 cm.

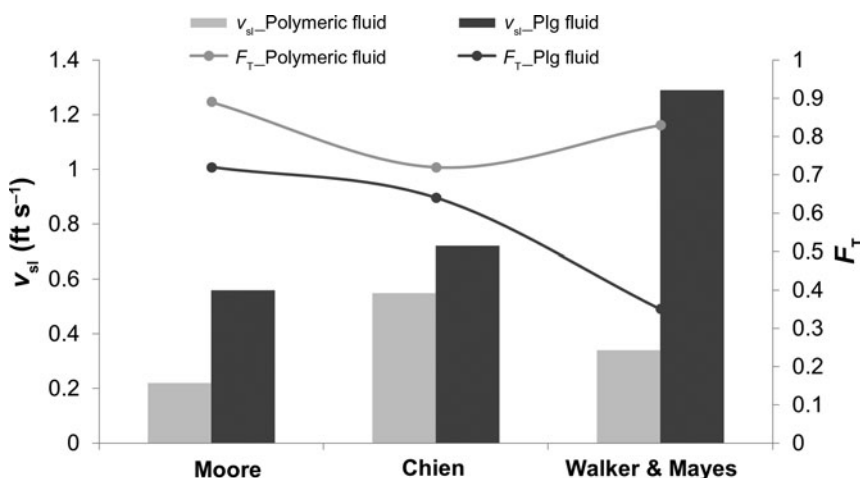
(Madruga *et al.*, 2018). In the Plg fluid, the Ca<sup>2+</sup> ions entered the channels of the clay mineral particles and caused shrinkage of the electrical double layer. The shrinkage of the electrical double layer led to face-to-face aggregation. This was observed by Zhang *et al.* (2016) when they added MgO to a drilling fluid with Plg. The aggregated clay minerals reduced the apparent viscosity of the drilling fluid and formed a mesh with an elongated particle mass and a more consistent filter cake, resulting in low filtrate loss. The same result occurred with the Na<sup>+</sup> ions dissociated from NaCl. Sulaiman & Al Zubaidi (2020) determined that a low concentration of caustic soda caused a decrease in  $\mu_a$  and poor dispersion (aggregation) in a drilling fluid with Plg due to Na<sup>+</sup> ions. Plg and sepiolite particles do not flocculate because of the reduced settling of the elongated crystals, thereby maintaining a constant volume capable of reducing permeability (Murray, 2000, 2006). Therefore, the results from the current study show that the Plg drilling fluid was more resistant to Ca(OH)<sub>2</sub> contamination.

Regarding GS, the Plg fluid, as a non-thixotropic fluid, can affect the cleaning of a drilling well. Zhang *et al.* (2016) obtained GS > 0 in suspensions with 6.4% Plg. Therefore, the use of this concentration of Plg can be used to obtain a thixotropic fluid. Plg particles can be considered as charged particles with zones of positive and negative charges. The bonding of these alternating charges allows them to form gel suspensions (thixotropic fluids) in salt water and fresh water (Zhang *et al.*, 2016).

Regarding alkalinity, Table 3 shows that in the polymeric drilling fluid contaminated with Ca(OH)<sub>2</sub> there is a decrease in the concentration of OH<sup>-</sup> ions present in the filtrate (P<sub>f</sub>) when compared to the base polymeric drilling fluid. This possibly occurs because there is adsorption of the contaminant (Ca(OH)<sub>2</sub>) in the solid fraction of the fluid.

### Cutting transport ratio

Table 4 presents the rheological parameters of the drilling fluids with an increase in polymeric fluid properties when compared

**Figure 1.** Cutting slip velocities and cutting transport ratios of the drilling fluids.

to those of the Plg fluid. In the three correlations, the  $N_{Re}$  is calculated as a function of apparent viscosity ( $\mu_a$ ), and  $N_{Re}$  is shown to be inversely proportional to  $\mu_a$ . In Moore's (1974) correlation,  $\mu_a$  is directly influenced by  $K$  (consistency index). As  $K$  was greater for the polymeric fluid,  $\mu_a$  was high and  $N_{Re}$  was low. In Chien's (1994) correlation,  $\mu_a$  is considered to be plastic viscosity ( $\mu_p$ ) for the Plg fluid because the fluid is clay-based.

For the purposes of calculating empirical correlations, in addition to drilling-fluid data, drilling well data from Bourgoyne Jr *et al.* (1991) were used (Table 5).

Using fluid rheology data, the correlations of Moore (1974), Chien (1994) and Walker & Mayes (1975) were used to estimate the cutting slip velocity and transport ratio values (Fig. 1).

As Fig. 1 shows, in relation to cutting slip velocity, the Plg fluid presented greater velocity than the polymeric fluid. This occurs because polymeric fluid has greater affinity for the aqueous phase of the fluid. Therefore, the polymeric fluid has a greater cutting carrying capacity. The difference between the Moore (1974) and Chien (1994) correlations is that the Moore correlation employs power-fluid model parameters ( $K$  and  $n$ ) to determine apparent viscosity, while the Chien correlation uses the Bingham model parameter ( $\mu_p$ ). The Walker & Mayes (1975) correlation defines the particles as circular discs in flat fall rather than as spheres.

With respect to the transport ratio, Fig. 1 shows that the polymeric fluid presented a greater transport ratio than the Plg fluid. A greater transport ratio is beneficial. The cutting transport ratio can be increased by increasing the annular fluid velocity or by adjusting fluid properties such as viscosity or density (Bourgoyne Jr *et al.*, 1991). According to Bourgoyne Jr *et al.* (1991), the lower the transport ratio, the greater the well damage will be. For example, increasing the cutting concentration in the annular region on the way to the surface increased the fluid density, which will cause an increase in the circulation pressure at the well bottom, decreasing the perforating rate of the drill.

### Conclusion

The results from this investigation show that the Plg drilling fluid was more resistant to contamination with Ca(OH)<sub>2</sub> and brine, resulting in a decrease in FV. The Plg fluid contaminated with 10% brine does not have adequate apparent viscosity (>15 cP). Therefore, in future work, it will be important to study drilling fluids with greater concentrations of Plg. Applying empirical

correlations, it was shown that the Plg fluid presented slip velocities that were 23.61–73.64% greater than those of the polymeric fluid. Regarding the transport ratio, as the values obtained were positive and >0, the Plg fluid has a good cutting-carrying capacity. These results represent an important contribution to the field as they highlight the advantage of using Plg in drilling operations, such as its resistance to contaminants and good cutting-carrying capacity, contributing to the advancement of clay mineral science and technology.

**Conflicts of interest.** The authors declare none.

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## Appendix

Conversion factors: US Field units to metric units.

Units	Multiply by	Answer in
Centipoise (cP)	0.0010	Pascal-second (Pa·s)
Feet per second (ft s <sup>-1</sup> )	0.3048	Meters per second (m s <sup>-1</sup> )
Inches (in)	2.5400	Centimetres (cm)
Pound force per hundred square feet (lbf 100 ft <sup>-2</sup> )	0.4788	Pascals (Pa)
Pounds per gallon (lb gal <sup>-1</sup> )	119.8260	Kilograms per cubic meter (kg m <sup>-3</sup> )