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MEASUREMENT METHOD FOR DENSITY OF DRILLING FLUIDS AT HIGH PRESSURE AND TEMPERATURE

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ABSTRACT

Large-scale deployment of CO_2 storage will require the drilling of numerous new wells, introducing additional operational challenges. One key concern is the potential influx of CO_2 into the wellbore during drilling operations, which can significantly alter the thermophysical properties of drilling fluids, including density and viscosity. A reduction in drilling fluid density or hydrostatic pressure may compromise well control and, in severe cases, lead to blowout incidents. It is therefore essential to quantify the impact of CO_2 dissolution on drilling fluid properties under representative downhole conditions, with pressures up to 400 bar and temperatures up to 100 °C.

Conventional densitometers are not suitable for these measurements due to the presence of solid particles in drilling fluids. To address this limitation, a dedicated experimental method was tested based on monitoring the volume changes of the fluid under controlled pressure, temperature, and CO_2 loading conditions. This paper first presents a detailed description of the experimental methodology. Subsequently, representative results are provided for drilling fluid density measurements, highlighting the influence from dissolved CO_2, pressure and temperature on fluid density behavior.

INTRODUCTION

Drilling fluids, commonly known as drilling muds, are essential to oil and gas well construction. Although they may appear to be simple circulating fluids, they are carefully engineered systems designed to perform several critical functions simultaneously. As drilling progresses, the drill bit generates significant heat and friction; drilling fluids cool and lubricate the bit, improving drilling efficiency and extending equipment life. They also transport drilled cuttings from the bottom of the wellbore to the surface, preventing accumulation that could cause blockages or stuck pipe. In addition, drilling fluids help maintain wellbore stability by forming a thin filter cake on the borehole wall, reducing fluid invasion and minimizing the risk of formation collapse. They also transmit hydraulic energy to downhole tools and suspend weighting materials and solids when circulation stops[1].

Among all drilling-fluid properties, density is arguably the most important because it directly controls the hydrostatic pressure exerted by the fluid column[2]. Maintaining the correct pressure balance is essential throughout drilling operations. If the fluid density is too low,

formation fluids such as oil or gas may enter the wellbore, leading to kicks and potentially blowouts[3]. Conversely, excessive density can fracture the formation, causing lost circulation and increasing operational costs. Achieving and maintaining the optimal density therefore requires continuous monitoring and adjustment.

The importance of density becomes even greater in complex drilling environments where gases such as CO_2 dissolve into the fluid or where multiple phases, including oil, water, and solids, coexist[4]. Under these conditions, density is not constant but varies with pressure, temperature, and composition. Even small changes can significantly affect well control. Consequently, accurate characterization of drilling-fluid density under realistic downhole conditions is essential for safe and efficient drilling operations.

Several techniques are available for density measurement. Simple methods include hydrometers, which determine density through buoyancy, and pycnometers, which calculate density from precise mass and volume measurements[5]. While both methods can provide reliable results, they are generally limited to laboratory conditions at ambient pressure and temperature. More advanced techniques include vibrating U-tube densitometers, oscillating piston densitometers, and optical methods such as refractometers and ultrasonic density meters. These instruments offer high precision for many fluids but are often best suited for particle-free, homogeneous systems[6].

For high-pressure and high-temperature applications, specialized instruments are required. Common options include high-pressure vibrating-tube densitometers, sinker-based densimeters, and pressure–volume–temperature (PVT) cells. However, when measuring drilling-fluid density in the presence of dissolved CO_2 over a wide pressure range (approximately 30–400 bar) and temperatures up to 100 °C, many conventional methods become inadequate.

Hydrometers and pycnometers cannot operate under controlled high-pressure conditions, while optical techniques are affected by suspended solids, emulsions, and CO_2 bubbles that interfere with light transmission or sound propagation. Vibrating U-tube densitometers, although highly accurate for single-phase fluids, face challenges with drilling muds containing barite, clays, cuttings, and dissolved gas. Solid particles can alter oscillation behavior, while CO_2 may come out of solution during pressure changes, forming bubbles that disrupt measurements. Tube fouling and erosion further reduce long-term reliability[7].

Similar limitations affect oscillating piston and sinker-based systems. Suspended solids can cause wear or sticking in piston mechanisms, while buoyancy-based measurements assume a uniform fluid phase that may not exist when CO_2 induces phase separation, foaming, or gas release. Temperature variations also influence fluid rheology and compressibility, further complicating accurate density determination[8].

Among the available techniques, the PVT cell offers significant advantages for complex drilling-fluid systems. Unlike oscillation- or buoyancy-based instruments, it determines density from direct measurements of fluid volume under controlled pressure and temperature conditions. This approach is less sensitive to solids, gas bubbles, and multiphase behavior, making it particularly suitable for CO_2-laden drilling fluids. Furthermore, PVT cells provide excellent control of thermodynamic conditions and can accommodate heterogeneous fluids while capturing the effects of gas dissolution, phase changes, and compressibility[9].

In this study, a high-pressure PVT cylindrical piston cell was used to investigate the influence of CO_2 on drilling-fluid density over pressures ranging from approximately 30 to 400 bar and temperatures from ambient conditions to 100 °C. The results provide valuable insight into density variations under realistic downhole conditions and demonstrate the suitability of the PVT-cell method for density measurements in CO_2-invaded drilling fluids. This validation is important because conventional density-measurement techniques are generally unable to

capture the combined effects of CO_2 dissolution, multiphase behavior, and suspended solids under high-pressure, high-temperature conditions.

METHOD

The experimental methodology for evaluating the density variation of drilling fluids under varying pressure, temperature, and CO_2 concentration is based on a high-pressure piston–cylinder (PVT) system designed to replicate downhole conditions. The cylindrical piston cell made up of titanium was used to perform experiments at high pressure and high temperature conditions. The core component of the setup is a 1 L piston-operated mixing cylinder connected to a hydraulic pump, which enables precise control of pressure and volume through piston displacement. The system is capable of operating up to approximately 400 bar and temperatures up to 100 °C, thereby covering the relevant thermodynamic range for drilling applications[10].

Initially, the base drilling fluid (oil-based or water-based) is introduced into the mixing cylinder at ambient conditions. Carbon dioxide, and in some cases methane, is then injected into the system using a secondary piston-cylinder gas transfer method. In this approach, the gas is first loaded into a separate gas cylinder at controlled pressure and volume and subsequently transferred into the mixing cylinder. This procedure allows accurate determination of the mass of injected gas and therefore the precise control of CO_2 concentration, expressed as the mass fraction of the total fluid–gas mixture[11].

Following gas injection, the system is pressurized and the mixture is homogenized to achieve thermodynamic equilibrium. Homogenization is enhanced by placing a rolling steel ball inside the cylinder and mounting the system on an oscillating platform or rocker. The mixture is typically agitated for extended periods (e.g., overnight) at high pressure to ensure complete dissolution of CO_2 into the drilling fluid and to avoid phase segregation.

To ensure that density measurements are conducted under single-phase conditions (i.e., with fully dissolved gas), the bubble point of the mixture is determined using a pressure–volume (P–V) expansion method. In this procedure, the piston is gradually withdrawn at a constant rate, resulting in controlled expansion of the fluid while continuously recording pressure. A distinct change in the slope of the P–V curve indicates the onset of phase separation, and the corresponding pressure is identified as the bubble point. All subsequent density measurements are performed at pressures above this threshold to prevent the formation of free gas and maintain a homogeneous fluid phase.

The density of the drilling fluid–CO_2 mixture is determined indirectly from the volume changes measured via piston displacement. Since the total mass of the system is known from the initial fluid loading and controlled gas addition, the density is calculated based on the measured volume of the mixture. The volume is inferred from the displacement of the hydraulic fluid in the piston system, with corrected for the compressibility of the hydraulic fluid and the mechanical deformation of the cylinder. By gradually adjusting the piston position, the relationship between pressure and volume is obtained, allowing evaluation of density as a function of pressure.

The measurement procedure typically begins with establishing a reference condition by determining the density of the base drilling fluid without dissolved gas over the pressure range of interest. Subsequently, CO_2 is introduced, and the density of the gas-loaded fluid is measured under identical pressure conditions while maintaining pressure above the bubble point. Temperature effects are incorporated by heating the mixing cylinder using an external heating jacket to specified values (e.g., 50 °C or 100 °C) and repeating the pressure–volume

measurements at each temperature. This approach allows systematic evaluation of density variation with respect to pressure, temperature, and CO_2-concentration within a single experimental framework[12].

Due to potential uncertainties in absolute volume determination, such as the presence of microscopic air bubbles in the hydraulic fluid, the method is particularly suited for determining relative density changes rather than absolute density values. Therefore, the results are often reported as density variations with respect to a reference state, typically defined as the density of the gas-free drilling fluid at ambient conditions. This approach improves measurement reliability while still capturing the impact of CO_2 dissolution and thermodynamic conditions on fluid density.

Overall, the piston–cylinder PVT method provides a robust and controlled approach for investigating the thermophysical behavior of drilling fluids exposed to CO_2. By integrating precise control of pressure, temperature, and gas concentration with continuous monitoring of volume changes, the method enables detailed characterization of density variation under realistic downhole conditions, thereby supporting both experimental analysis and the development of predictive models for well-control applications.

RESULTS AND DISCUSSION

Evaluation of the cylinder volume

The density evaluation first requires a careful evaluation of the cylinder volume in the whole range of studied pressure and temperature. The assessment of the cylinder volume was carried out in three steps:

1- Evaluation of a reference volume, at room temperature and one pressure (50 bar)
2- Evaluation of volume change under pressure variations.
3- Evaluation of the volume change under temperature variations.

For the first step, the volume of the cylinder at 50 bar was evaluated by displacing the inner piston from one end of the cylinder to the other at constant pressure, we found that the volume at 50 bar and 23°C was 1010 mL.

Secondly, a test was performed with water only to evaluate the dilatation of the cylinder at room temperature. The pressure increased from atmospheric pressure to 400 bar, then decreased from 400 bar to atmospheric pressure. The data in **FIGURE 1** shows the volume change of the cylinder during pressure ramp (b), calculated from the amount of water received by the pump (a).

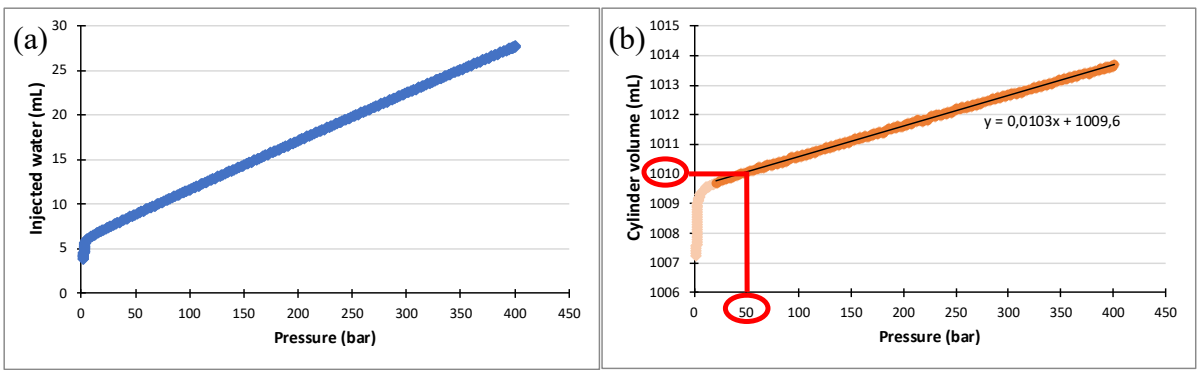

FIGURE 1: (a) Cumulative water volume injected by the pump during pressure increase at 23°C. (b) Deduced cylinder volume at room temperature, deduced from graph (a) and taking into account water

compressibility. The orange curve shows the experimental data, while the black line shows the linear regression in the range 20 - 400 bar.

We first note that the injected water – pressure relation is linear in the range 30 – 400 bar. However, at lower pressure, the curve does not follow this linear trend. We believe that this is due to the presence of a small amount of air bubbles in the water, which dissolve when the pressure reaches 30 bar. This indicates that the density method presented in this paper should be limited to for pressures above about 30 bar. The cylinder volume is calculated from the injected water volume, taking into account the compressibility of water. The volume at 50 bar is adjusted to the reference value 1010 mL. We see that when the pressure is about 30 bar, the pressure sensitivity for the cylinder volume at 23°C is given by the linear relation:

$$\text{V [in mL]} = 0{,}0103\ \text{P [in bar]} + 1009{,}6 \qquad (1)$$

To take into account the effect of temperature on the volume, Eq. 1 is corrected using the volumetric thermal dilatation coefficient of titanium: $\alpha = 3 \cdot 10^{-5}\ K^{-1}$, giving:

$$\text{V [in mL]} = (0{,}0103\ \text{P [in bar]} + 1009{,}6) \cdot (1 + \alpha(T\ [in\ °C] - 23)) \qquad (2)$$

Eq. 2 shows that the cylinder volume increases by about 4 mL when the pressure is increased from 50 to 400 bar, while an increase of the temperature from 23°C to 100°C leads to a volume increase of 2 mL

Validation of the method

Some tests have been performed using a base oil to check that the effect of density variation with pressure are well captured with the cylinder method. The density measured with the cylinder is compared with densitometer measurements in **FIGURE 2**.

As mentioned before, the cylinder tests do not provide an absolute density evaluation, therefore the initial oil volume has been manually adjusted to ensure that the density at 50 bar measured by both method match. **FIGURE 2** shows that the slope of the pressure-density curve is the same for both methods. The density at 1 bar obtained from the cylinder method is 5 kg/m^3 lower than the density read from the densitometer; this is as explained before due to a small amount of bubbles in the liquid in the cylinder.

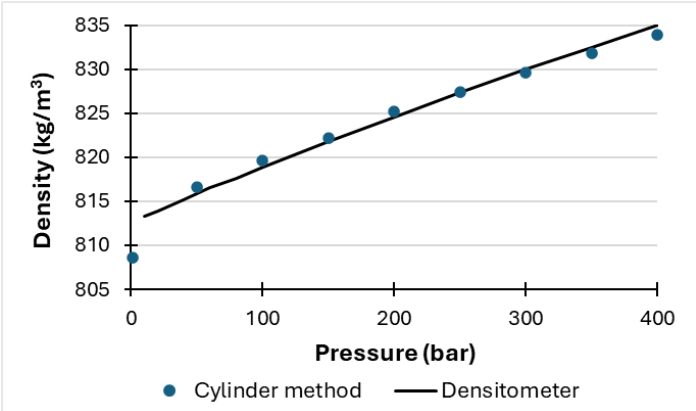

FIGURE 2: Comparison of density measured by the cylinder method and by an Anton Paar densitometer

Results on an oil-based drilling fluid with dissolved CO2

A drilling fluid – CO2 mixture has been prepared following the method described by Skogestad et al. (2024)[12]. Here, we present the results of the density measurements obtained with the cylinder method. In these experiments, we measured consecutively the density for the following conditions (pressure was not decreased below 30 bar after the experiment was started):

1- Fluid without CO_2 at 23°C
2- Fluid without CO_2 at 50°C
3- Fluid without CO_2 at 100°C
4- Fluid with CO_2, 4% of the total weight, at 23°C
5- Fluid with CO_2, 4% of the total weight, at 50°C
6- Fluid with CO_2, 4% of the total weight, at 100°C
7- Fluid with CO_2, 4% of the total weight, at 23°C

Steps 4 and 7 are similar conditions and allow us to check the repeatability of the test. The measured pressure-density curves are shown in **FIGURE 3**. We observe that the density of the drilling fluid decreases when the temperature increases and decreases when CO_2 is dissolved.This is in agreement with previous observations[10,11].

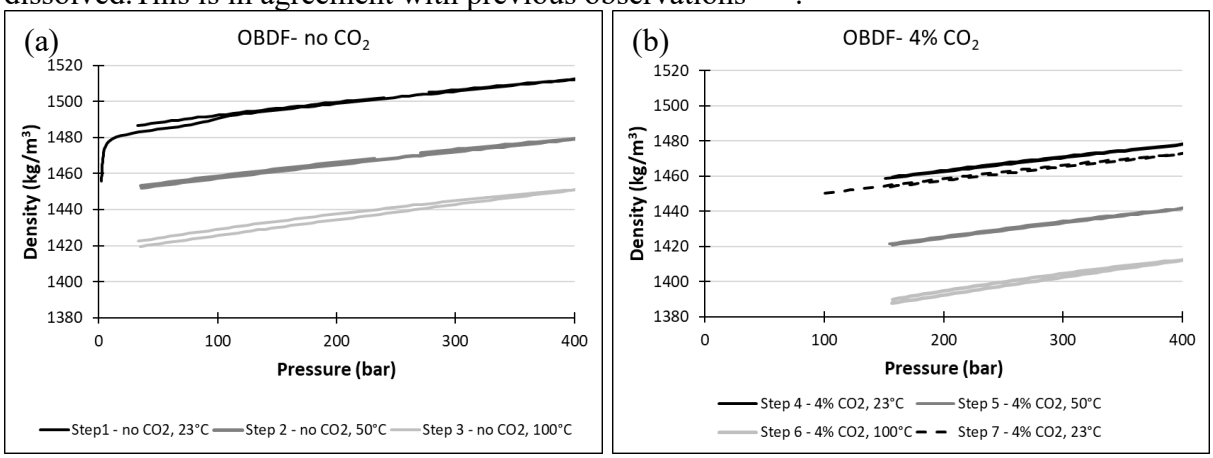

FIGURE 3: Density measurement on oil-based drilling fluid at three different temperatures, (a) without dissolved CO_2 and (b) with 4% CO_2 weight fraction.

Skogestad et al. (2024)[12] have shown that the density of an oil-based drilling fluid after dissolution of 8% CO_2 by weight could be correlated with the density of base-oil – CO_2 mixture, under the assumption that the CO_2 dissolves only in the base oil (and not in the brine droplet or solid phases). Similarly, we can compare the experimental density values from **FIGURE 3** with the theoretical density, calculated from the density of the components. The assumptions for this calculation are as follows:

- The initial fluid is composed of three phases: base oil (56.6%, 835 kg/m^3), brine (24.3%, 1200 kg/m^3) and solids (19.1%, 3900 kg/m^3). The solid fractions have been provided by the manufacturer, the base oil density has been measured, the other densities at 400 bar have been estimated so that the density of the OBDF at 23°C and 400 bar is about 1510 kg/m^3.
- The volumetric thermal dilatation coefficient of brine is 4.10^{-4} K^{-1} [13]; the density of the brine droplets is therefore 1187 kg/m^3 at 50°C and 1164 kg/m^3 at 100°C. No CO_2 dissolves in brine.
- The volumetric thermal dilatation coefficient of solids is 4.10^{-5} K^{-1} [14]; the density of the solids is therefore 3896 kg/m^3 at 50°C and 3888 kg/m^3 at 100°C.

- The density of the base oil is affected by the temperature and the CO_2 loading, as shown in **FIGURE 4** (a). Assuming that the CO_2 dissolves only in the base oil, 4% of CO_2 by weight of OBDF corresponds to 12% of CO_2 by weight of base oil. The densities of the base-oil with dissolved CO_2 are therefore 852 kg/m^3 at 23°C, 833 kg/m^3 at 50°C and 797 kg/m^3 at 100°C.

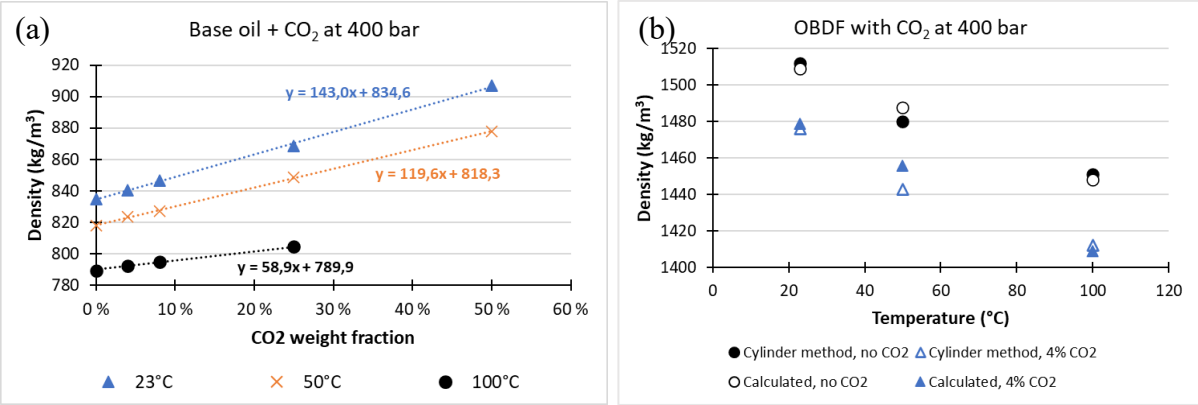

FIGURE 4: (a) Density measured with the densitometer for base-oil CO_2 mixtures, at 400 bar. Data from Skogestad et al. (2024)[12]. (b) Density of OBDF – CO2 mixtures at 400 bar. The filled symbols represents measurements with the cylinder method and are taken from **FIGURE 3**. The empty circles and triangles are calculated values.

FIGURE 4 (b) shows that under these assumptions, the calculated values are similar to the values measured by the cylinder method. It confirms that the cylinder method serves to accurately measure the variation of the drilling fluid density as a function of temperature, pressure, and dissolved gas content.

CONCLUSION

We have presented in this paper a method to evaluate how the density of a fluid is affected by pressure, temperature and gas content. We show that for a simple fluid (base oil), this method gives similar results as a densitometer. The advantage of this method is that it is effective to study complex industrial fluids such as drilling fluids, as it does not have any limitations regarding volume content and size of particles.

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