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Examination of Drill Pipe Corrosion in Water Based Drilling Fluids under Wellbore Conditions

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Abstract: Drill-pipe corrosion is a critical issue for any drilling operation, particularly under high-pressure, high-temperature (HPHT) downhole conditions. However, most laboratory studies have been conducted under ambient and static conditions, with only a few downhole studies based on flow loop showing inconsistent results. In this study, we proposed a novel simple method to simulate pipe corrosion/erosion in a reservoir-like environment under both the static and dynamic conditions and investigated the influences of wellbore conditions, including temperature, pressure and salinity of water-based drilling fluids, on the corrosion behaviour of the drill pipe. The results showed that the erosion effect of the drilling fluid (without drilled cuttings) was negligible. Furthermore, we found that the corrosion rate increased with an increase in the temperature, pressure and rotational speed; however, it decreased with an increase in the salinity. In addition, the proposed method can be used to simulate other complicated conditions.

Keywords: Drilling fluid, drill pipe, corrosion, wellbore condition, high pressure and high temperature

1. Introduction

Every rotary drilling process comprises three structures that simultaneously operate while drilling a wellbore: a rotation system that rotates the drill pipe, a hydraulic system that raises and turns down the drill string into the wellbore and a circulatory system that performs all the functions associated with the fluid movement. This fluid is referred to as the drilling fluid or drilling mud. The drilling fluid is essential for completing the drilling operation because it could increase oil recovery and reduce the time required to obtain the primary production [1]. The difficulties experienced during drilling operations in the petroleum industry have led to the preparation of different types of drilling mud. Nevertheless, besides chemicals, these typesof mud majorly comprise water, oil and gas. Based on the base fluid, these types of drilling mud are categorised as water-, oil- and gas-based mud [2]. The oil-based mud is suitable for most drilling operations and is less corrosive than the other types. However, some of these drilling operations are restricted due to environmental regulations [3]. In contrast, the water-based mud is inexpensive, can be easily controlled and is environmentally friendly[3].Shokoya confirmed that the water-based drilling fluidsare the most favourable amongst the other types owing to their aforementioned advantages [4].

The corrosiveness of water-based drilling fluids is a major problem in the drilling operation and is still required to be resolved. Advancements in drilling engineering pose an additional challenge for the use of drilling fluid due to severe environmental conditions.Fordeep and ultra-deep wells, wherein the temperature and pressure are high, drilling fluids tend to be more corrosive. According to one of the oil companies of China, drilling fluids consume 4 kg of drill pipe per meter depth. The losses by corrosion were estimated from 20%–50% of the total drilling cost [5]. Another study has shown that the drilling fluid corrosion losses are approximately 60%of the total drilling cost due to the failures caused by the drilling fluids and costs associated with these incidents [6]. Drilling fluids are corrosive due to the presence of dissolved gases, such as O_2, CO_2 and H_2S, and erosion by chemical composition or drilled cuttings during the drilling process.

Corrosion investigation under downhole conditions can provide information regarding the corrosiveness of the drilling fluid and the type of corrosion encountered. It is difficult to effectively simulate the chemistry, harsh conditions and flow components of the drilling process in a laboratory. Moreover, very few studies have investigated the corrosive effects of the drilling fluid environments on drill pipes. These studies were limited to specific working conditions, and most of these studies were conducted under ambient and static conditions, which were considerably different from the actual corrosive conditions present during a drilling operation [5, 7, 8]. Dynamic tests were mainly performed in simple glass cells comprising rotating cylinder electrode (RCE), which could exhibit some basic corrosion characteristics but not the downhole conditions or large flow loops under high pressure and temperature that were used to mimic the complex and expensive downhole conditions [9-11].

In a practical operation, the drilling fluid cycle is often unstable and alternates between the static and dynamic states,and usual ambient steady corrosion test could not simulate the highly corrosive conditions presenting in a drilling operation[5]. To control and mitigate corrosion, it is necessary to understand how drilling fluids under downhole conditions influence the process of corrosion and the factors affecting the values of the corrosion rates. This research aims to improve our understanding of the corrosion process of drilling fluids. A novel simple method was used to mimic drill-pipe corrosion for both the static and dynamic tests under high-pressure, high-temperature (HPHT) working conditions. An HPHT cell autoclave with a mechanical stirrer driven by a shaft was used to simulate the flow condition and investigate the effect of rotation speed. Instead of using a flat surface, a cylindrical coupon made of a typical pipe material, i.e. steel X95, was mounted at the lower end of the shaft, which rotated in the HPHT cell filled with drilling fluids. The coupon simulates the shape of the drill pipe. Factors, including the temperature, pressure and salinity of the drilling mud on the corrosion behaviour of the drill pipe were analysed to investigate their effect on the corrosion rates of the samples. In addition, as Haaland (1976) reported, the particle size and the hardness of the additives could lead to erosion corrosion [12], scanning electron microscopy (SEM) imaging and a pure erosion test were conducted to study the surface characteristics.

2. Experimental Methods

Preparation of Water-Based Drilling Fluids

A water-based drilling fluid was prepared by scaling water to a certain amount. First, bentonite was added to the water, which was mixed thoroughly with the fluid. Subsequently, barite and other chemicals, i.e. soda ash and sodium chloride, were added and mixed using a Hamilton Beach mixer for 20 min. Table 1 summarises the chemical composition of the drilling fluid.

2.1 Specimen reparation

A cylindrical coupon was machined. The dimensions of the samples are like those shown in Figure 1. The internal and external diameters of the coupon were 4.8 and 10 mm, respectively. The height of the coupon and its total surface area exposed to the corrosive environment were 5 mm and 1.5708 cm^2, respectively. Furthermore, the coupons were made of API drill pipe grade X-95. A sample holder made of PTFE was machined to fit on an autoclave rotating shaft. The sample was polished with 400- and 600-grit silicon carbide papers using water and cleaned with acetone in an ultrasonic bath. Then, the sample weighted using OHAUS Discovery semi-micro and analytical balance (model: DV114C), which has an accuracy of 0.0001 g, was used to determine the mass of the coupon prior to immersion.

Table 1. Components of the prepared water-based mud.

Component	Quantity
Water	335 ml
Bentonite	15 gm
Barite	5 gm
Soda ash (Na_2Co_3)	0.2 gm
NaCl	0–33.5gm

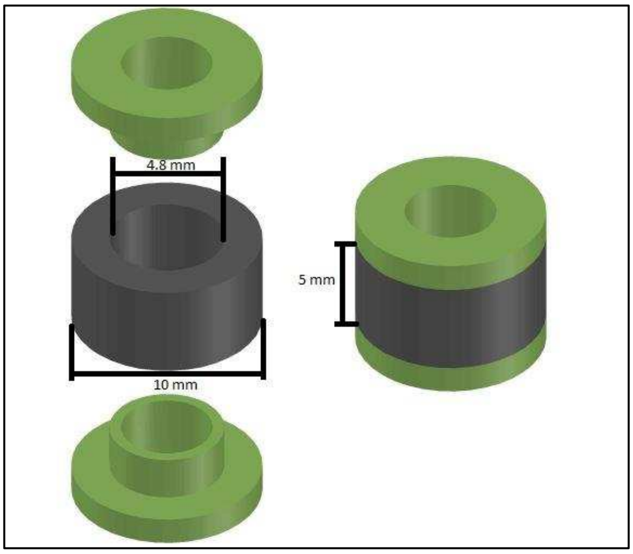

Figure 1. AutoCAD design of the corrosion coupon and PTFE insulator.

2.3 Corrosion Investigation

A 100-ml stirred autoclave was used to simulate the HPHT and flow conditions. The temperature and pressure can be controlled up to 350 C and 350 bar respectively. The cell was placed in a built-in oven for controlling the temperature, and the pressure was controlled using a separate air cylinder. Furthermore, the cell was installed using a rotating shaft with a maximum speed up to 600 rpm and filled with the drilling fluid. Subsequently, the coupon was immersed in this cell.

The drill-pipe coupon was suspended in the drilling mud at specific conditions for at least 40 hr. At the end of each test, the coupon was cleaned with acetone and dried with hot air, after which it was weighted. The weight loss within the immersion period was determined as the difference between the initial and final weights. Each experiment was at least repeated twice to obtain reproducible data. The surface characteristics were analysed using SEM imaging. Then, the corrosion rate (mm/year) was calculated using the followingformula [13]:

$$\text{Corrosion Rate (mm/year)} = \frac{87.60 \times \text{weight loss (mg)}}{\text{density}\left(\frac{\text{mg}}{\text{cm}^3}\right) \times \text{area}(\text{cm}^2) \times \text{time (hours)}}$$

Figure 2. The suspension of the corrosion coupon at the lower end of the shaft and the stirred autoclave.

2.4 Pure Erosion Investigations

To determine the possible erosion influence of the drilling fluid components (i.e. bentonite and barite), a simple procedure was used by measuring the weight loss of a metal sample before and after being exposed to an erosion condition, as suggested in a previous study [14]. In the experiments, a pure erosion experiment was performed using N_2 gas for 12 hr to eliminate the effect of O_2 from the drilling fluid and minimise any corrosion occurring due to the drilling fluid. Then, the drill-pipe coupon was suspended in a saturated drilling fluid with N_2 at specific conditions for at least 40 hr and the weight loss was accordingly determined.

2.5 Surface Morphology Observation

Before and after the corrosion tests, the surface morphologies of the drill-pipe coupons were examined via SEM (Hitachi TM3030 Benchtop SEM) to study the surface characteristics of the coupons and determine whether the drilling fluid causes any surface damage, such as cracks or wears, to the drill-pipe coupon.

3. Results and Discussion

3.1 Effect of Temperature and Pressure on Corrosion Rate

Experiments were performed to investigate the effects of temperature and pressure on the corrosion rate values of carbon steel. For temperature tests, experiments were performed at 50 bar pressure and 100 rpm. Four temperature values (i.e. 20 °C, 45 °C, 70 °C and 95 °C) were considered to determine the effect of temperature on corrosion rates. Data from Figure 3 show that temperature has a significant effect on the corrosion rates. The corrosion rate is increased by nearly four times when the temperature is increased from 20 °C to 95 °C. An increase in the temperature accelerates all reactions, thereby accelerating the diffusion rate of the O_2 species. Therefore, corrosion rates values increased because more O_2 species transport from the bulk and react at the surface [15-18].

In contrast, for the pressure test, experiments were performed at a constant temperature of 25 °C and a rotation speed of 100 rpm. Figure 4 shows the effect of pressure on the corrosion rate. An increase in the pressure has a negligible effect on the corrosion rate values compared with temperature. It is believed that an increase in the pressure has an impact on corrosion by increasing the solubility of O_2. In addition, an increasing in the pressure indicates an increase in the O_2 concentration. Thus, more species react at the surface [19].

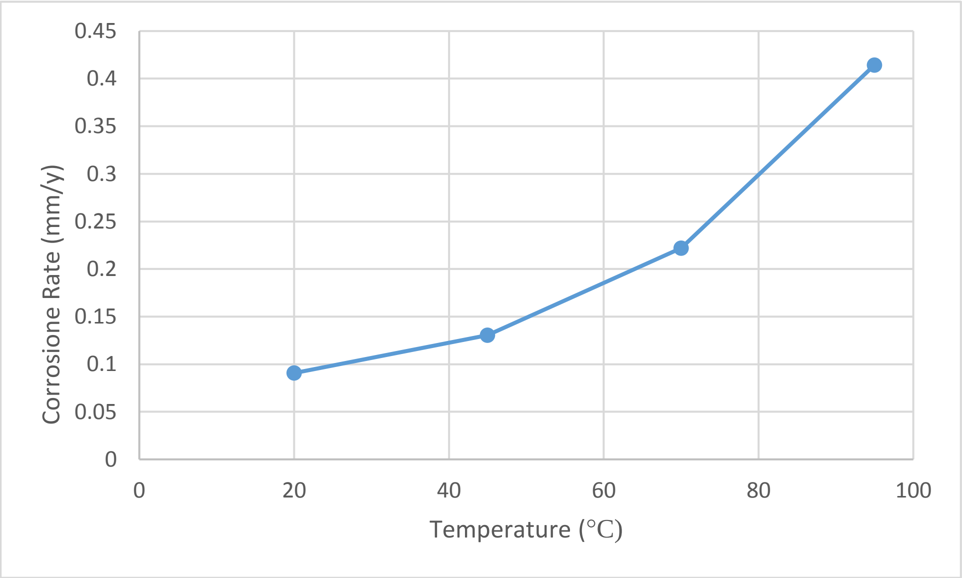

Figure 3. Effect of temperature on corrosion rate (50 bar and 100 rpm).

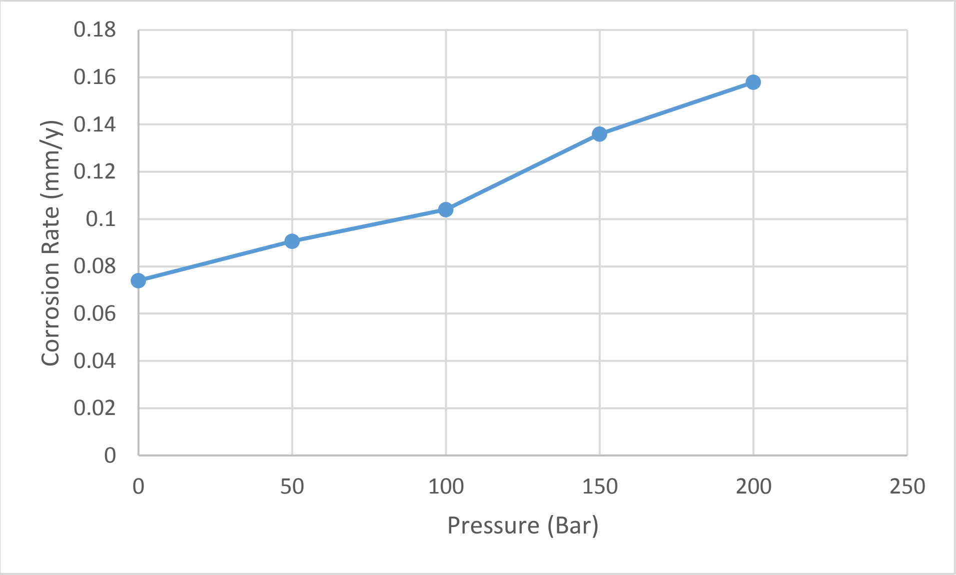

Figure 4. Effect of pressure on corrosion rate.

3.2 Effect of Rotation Speed on Corrosion Rate

Figure 5 shows the variations in the corrosion rates with the drill-string rotation speed at ambient temperature and pressure. The corrosion rate gradually increases with an increase in the rotation speed, which promotes high turbulence and causes effective mixing, leading to an increased O_2 transport rate and the corrosion rate. In contrast, an increase in the rotation speed can reduce the thickness of the water boundary layer next to the metal surface. This thin boundary layer allows dissolved O_2 to corrode the steel surface[20]. Thus, the experimental results show that the corrosion rate is increased by approximately fourfold when the rotation speed increased to 600 rpm.

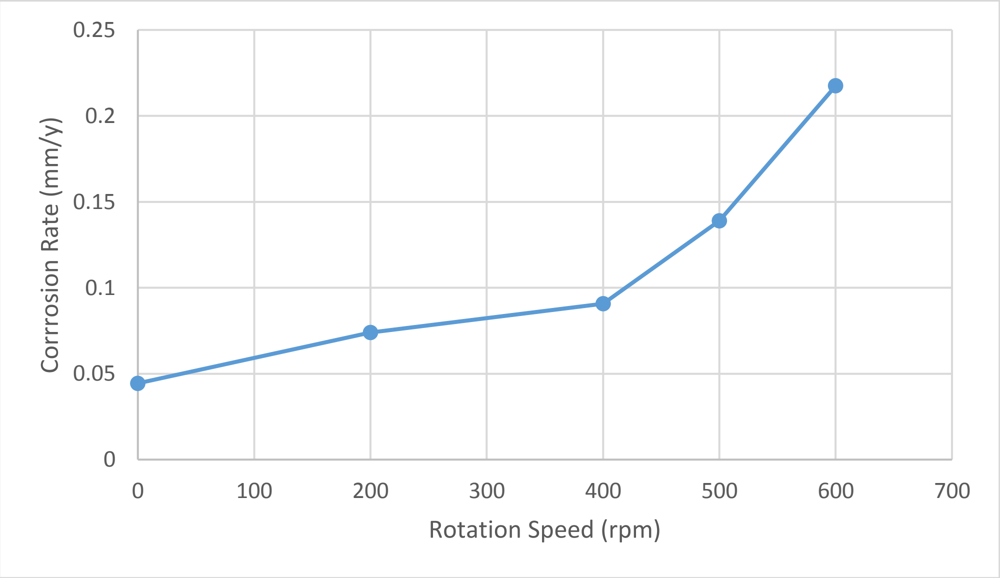

Figure 5. Effect of rotation speed (in rpm) on corrosion rate.

At a high speed of 600 rpm, to distinguish between the mass transfer and erosion effects using chemical composition of the particles, a deaerated erosion test was performed to determine the amount of metal loss by the drilling fluid at ambient temperature and pressure. It is believed that a high particle velocity increases the erosion rate [14, 21, 22]. However, the weight loss measurement showed that the corrosion rate from erosion is considerably small, i.e. up to 0.004633 mm/year. These results confirm that the main source of corrosion is the dissolved species rather than the erosion caused by the drilling fluid chemicals.Figure 6 shows the SEM images before and after the erosion test (600 rpm; 1 bar; 20 °C). The SEM images in Figure 6 show that there is no change in the surface texture after the pure erosion test. In addition, it is clearly evident from Figure 6 that there is no clear wear or crack on the metal surface, indicating that the erosion caused by the drilling fluid is negligible.

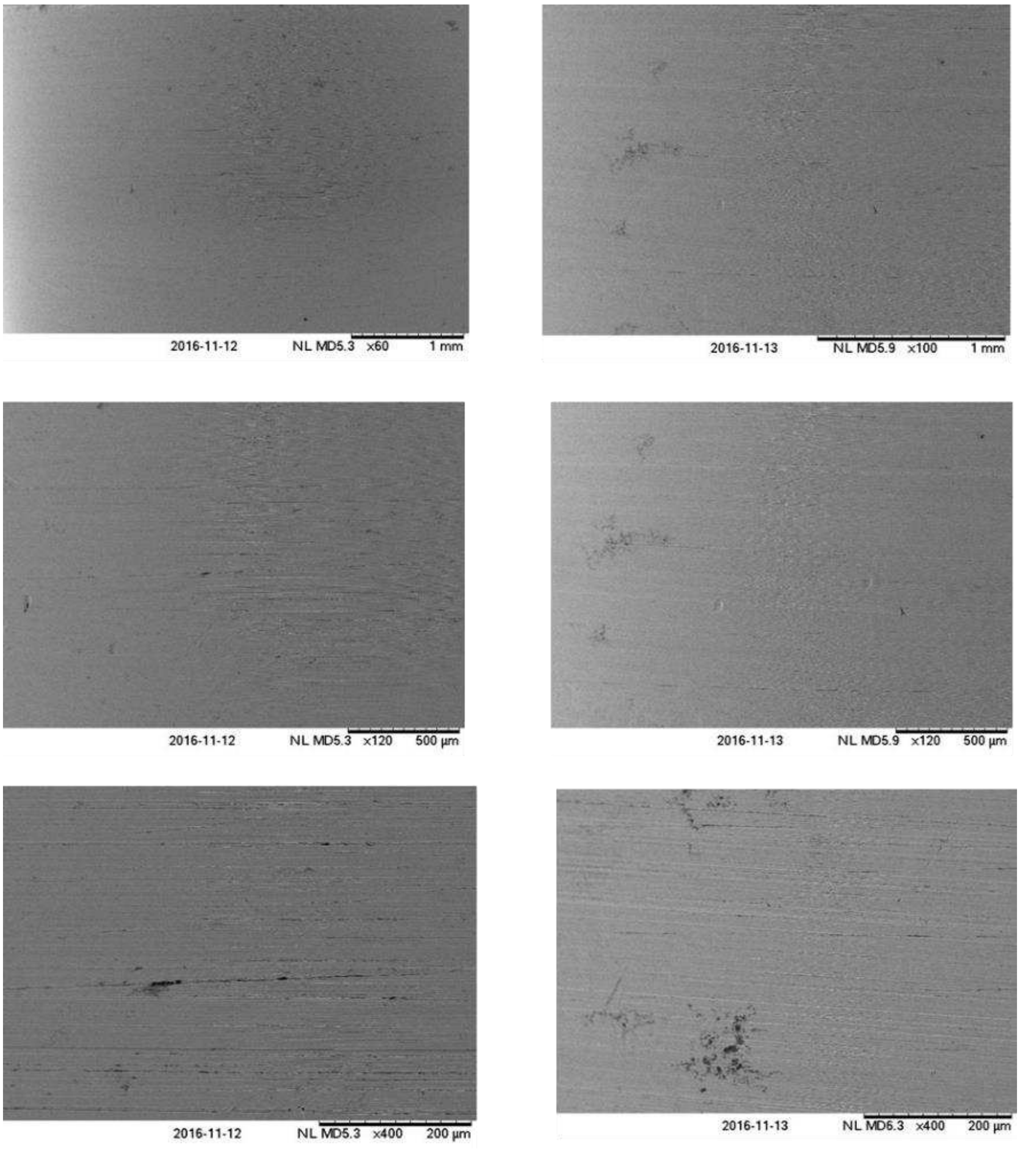

Figure 6. Scanning electron microscopy (SEM) images before and after the pure erosiontest.

3.3 Effect of SalinityConcentration on Corrosion Rate

The variations in the corrosion rates with the drilling fluid salinity at ambient temperature and pressure at a constant rotation speed of 400 rpm are shown in Figure 7. It is evident from the figure that the corrosion rate decreases with the increase in the salinityconcentration. This occurs because the higher concentration of NaCl causes an increase in the fluid's density and viscosity. In addition, a high NaCl concentration increases the ionic strength, which decreases the amount of dissolved O_2 existing in the system[8, 23]. Study by Fang et al. has demonstrated that the increase in salt concentration leads to decrease in the corrosion rates. They attributed this reduction in corrosion rates to the electrochemical reactions. Their results showed that both cathodic and anodic reactions were retarded as the salt concentration increased [24]. In recent studies, the experimental results by Han et al. supported the findings by Fang and confirmed their conclusion [25].

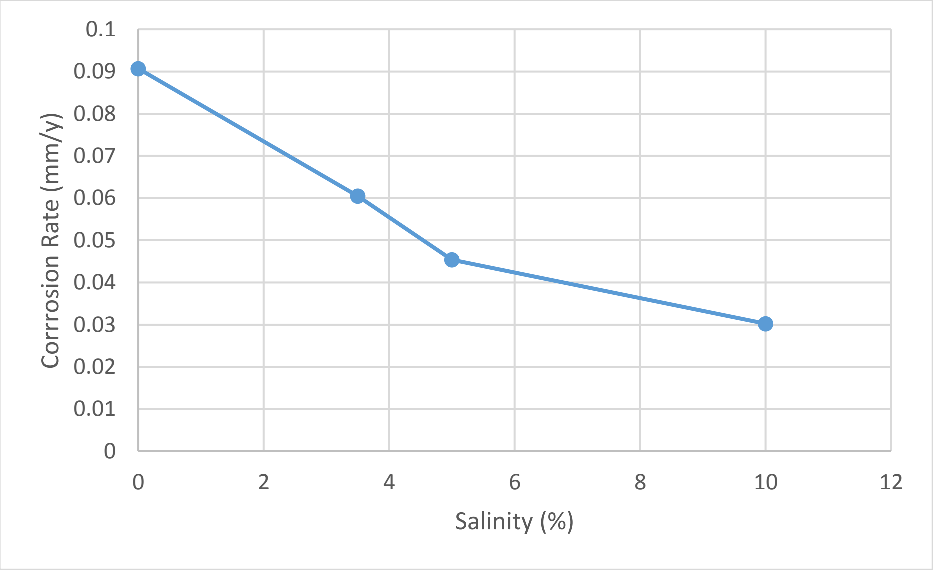

Figure 7. Effect of salinity concentration on corrosion rate.

These results show that this simple method can be used to simulate the corrosion behaviour of drilling fluids under reservoir-like conditions, which enable us to investigate the effect of various influencing parameters. The corrosion data that was difficult to obtain under flow and high temperature and high pressure conditions can be easily obtained by this new method, which can be also extended to simulate other complicated conditions.

4. Conclusions

A novel simple method to examine the pipe corrosion in a reservoir-like environment was proposed in this research, and a parametric study investigating the factors influencing the corrosion rate was conducted, which can be summarised as follows:

- A simple stirred autoclave was used to simulate downhole conditions for corrosion investigation, which is more beneficial than using an HPHT flow loop that is generally large and expensive.
- A coupon rotating inside the autoclave was be used to appropriately simulate the drilling pipe corrosion and investigate the effects of the fluid chemistry and operational parametersdrill-pipe corrosion in a laboratory.
- The parametric study results showed that the corrosion rate increases with an increase in the temperature, pressureand rotational speed; however, it decreases with an increase in the salinity concentration as shown in figures 3, 4, 5 and 7 respectively.
- The erosion rate of the drilling fluid showed a negligible effect compared to those observed in the corrosion experiments under the same conditions, which confirmed the dominant effect of corrosion in the work.

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